BOOK III

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 1 – HANS G. BELL
UGI GAS STATEMENT NO. 2 – TRACY A. HAZENSTAB
UGI GAS STATEMENT NO. 3 – VIVIAN K. RESSLER
UGI GAS STATEMENT NO. 4 – JOHN F. WIEDMAYER
UGI GAS STATEMENT NO. 5 – VICKY A. SCHAPPELL

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 55

DOCKET NO. R-2024-3052716

Issued: January 27, 2025 **Effective: March 28, 2025**

UGI GAS STATEMENT NO. 1

HANS G. BELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 1

Direct Testimony of
Hans G. Bell

Topics Addressed:	**Purpose of Testimony and Rate Filing Overview** **Need for Rate Relief** **Compensation Adjustments** **Cybersecurity Audit Adjustment** **Competitive Customer Analysis** **Management Effectiveness and Performance**

Dated: January 27, 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Hans G. Bell. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI") as its President. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. As President, I am accountable for delivering the overall business performance to ensure adequate, efficient, safe, reliable, and reasonable natural gas and electric utility service to UGI's customers.

Q. What is your educational and professional background?

A. Please see my resume, UGI Gas Exhibit HGB-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit HGB-1 contains a list of those proceedings.

II. PURPOSE OF TESTIMONY AND RATE FILING OVERVIEW

Q. Please describe the purpose of your testimony in this proceeding.

A. My testimony addresses several areas. First, I present an overview of the rate filing, including a brief explanation of the reasons for rate relief and an outline of the testimony of each witness in this proceeding. Second, I describe certain compensation adjustments related to both salaries and wages as well as anticipated impacts resulting from upcoming contract negotiations with certain unions in the future test year ("FTY"). These compensation adjustments are, or will be, reflected as additions to the fully projected test year ("FPFTY") budgets, which are the starting point for UGI Gas's claim in this proceeding. Third, I discuss an adjustment which is being made related to UGI's biennial cybersecurity audit. Fourth, I discuss the Company's compliance with the competitive customer analysis, as required in the 2019 Rate Case Settlement at Docket No. R-2018-3006814. Lastly, I summarize the evidence of UGI Gas's successful management performance and propose how it should be recognized in this case.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring UGI Gas Exhibit HGB-1. Also, I am sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing.

Q. Please identify the other witnesses providing direct testimony on behalf of UGI Gas in this proceeding and the subject matter of their testimony.

A. In addition to my testimony, the following witnesses are providing testimony in support of the Company's rate request:

Tracy A. Hazenstab (UGI Gas Statement No. 2) holds the position of Sr. Manager – Utility Rates for UGI Gas. She addresses operating revenues and expenses; compliance with Section 1301.1 of the Public Utility Code; and the revenue requirement model supporting the Company's proposed rate increase, UGI Gas Exhibit A (Fully Projected). Ms. Hazenstab also sponsors the revenue requirement models for the future and historic periods, UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic), respectively.

Vivian K. Ressler (UGI Gas Statement No. 3) holds the position of Director – Utility Financial Planning & Analysis ("FP&A") at UGI. Ms. Ressler explains UGI Gas's accounting processes used to develop the Company's actual book accounting results, which are the basis for the Historic Test Year ("HTY") ended September 30, 2024. Ms. Ressler also presents UGI Gas's rate base claim for the HTY, FTY, and FPFTY. Ms. Ressler further addresses the budgeting process and certain operating expense adjustments, as well as the Company's accounting for information technology costs.

John F. Wiedmayer (UGI Gas Statement No. 4) holds the position of Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports UGI Gas's claim for annual depreciation expense, and the accumulated depreciation reserve. His studies are presented in UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic).

Vicky A. Schappell (UGI Gas Statement No. 5) holds the position of Sr. Manager, Capital Planning for UGI Gas. Ms. Schappell addresses capital expenditures and capital planning, including those for including the plant in service expenditures for the FTY and FPFTY.

Proposed spending addressed by Ms. Schappell includes two large IT projects – Field Services Management ("FSM") and Extended Asset Accounting ("EAA").

Paul R. Moul (UGI Gas Statement No. 6) holds the role of Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony supporting the Company's claimed capital structure, cost of debt, cost of common equity, and overall fair rate of return. Schedules and workpapers supporting Mr. Moul's findings are set forth in UGI Gas Exhibit B (Rate of Return).

Darin T. Espigh (UGI Gas Statement No. 7) holds the position of Sr. Manager – Natural Gas Tax Accounting. Mr. Espigh addresses various tax issues, including the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, the repairs allowance and the differential consolidated tax use calculation as required by Section 1301.1 of the Public Utility Code.

Sherry A. Epler (UGI Gas Statement No. 8) holds the position of Senior Manager Tariff and Supplier Administration for UGI Gas. Ms. Epler's testimony addresses the development of the Company's HTY, FTY and FPFTY test year sales and revenues. In addition, Ms. Epler addresses several proposed tariff updates. Ms. Epler sponsors UGI Gas Exhibit E (Proof of Revenue) and UGI Gas Exhibit F (Current and Proposed Tariffs).

Christopher R. Brown (UGI Gas Statement No. 9) holds the position of Vice President of Operations. Mr. Brown's testimony addresses UGI Gas's operations and natural gas system. In addition, Mr. Brown discusses UGI Gas Long-Term Infrastructure Improvement Plan ("LTIIP"), and the impact of the LTIIP and other initiatives on system performance, safety, and reliability. Also, Mr. Brown addresses UGI Gas's efforts and future plans to investigate and, where necessary, remediate sites in Pennsylvania where UGI Gas or corporate predecessors once owned and/or operated manufactured gas plants in connection with gas utility operations. Lastly, Mr. Brown details and supports several key areas of focus and related adjustments related to his testimony topics: (a) Pipeline Contractor price increase impacts; (b) Material Verification of Transmission Assets; and (c) Advanced Leak Detection activities.

John D. Taylor (UGI Electric Statement No. 10) is a Managing Partner of Atrium Economics LLC. Mr. Taylor prepared and sponsors UGI Gas's fully allocated cost of service study. This study is contained in UGI Gas Exhibit D. The Allocated Cost of Service Study ("ACOSS") allocates the Company's cost of service associated with Commission jurisdictional operations to the Company's customer classes. Mr. Taylor also addresses the Company's proposed revenue allocation and rate design.

III. NEED FOR RATE RELIEF

Q. Please discuss UGI Gas's proposed rate relief request and provide an overview of the Company's proposals in this proceeding.

A. UGI Gas is requesting an increase in its annual base rate operating revenues of $110.395 million, or 9.7 percent on a total revenue basis, with a proposed effective date of March 28, 2025. The base rate increase requested in this filing utilizes a FPFTY ending September 30, 2026. UGI Gas continues to make substantial distribution system investments that are necessary to: (1) continue the accelerated replacement of aging gas plant infrastructure; (2) upgrade and improve system segments and modernize facilities; (3) serve new residential and commercial customers, including natural gas conversions; (4) install and upgrade supporting information technology systems; and (5) most importantly, ensure the safety of the Company's employees, customers, the communities it serves, and its distribution system. Moving forward, these system improvements and investments will require the Company to continue its efforts to attract, recruit, train, and retain those professional, technical, and field-qualified personnel and resources necessary to implement, operate, and maintain those investments. These investments are all necessary to grow and continue to maintain a safe and reliable distribution system and provide quality customer service. As compared to pre-FPFTY gross plant levels, UGI Gas is projecting an increase of approximately $423 million in gross plant through the FPFTY compared to the end of the FTY and $786 million in gross plant when compared to the end of the HTY. Based on this factor alone, UGI Gas's current rates will not provide it with a reasonable opportunity to earn a fair rate of return on its increased rate base investments.

Other cost drivers also reduce the Company's ability to earn a reasonable rate of return on its utility investments. Since its last base rate case in 2022, UGI Gas has adopted certain wage and salary adjustments in order to retain and attract qualified employees. UGI Gas will continue to do so where necessary to maintain a productive and effective workforce and, additionally, has plans for certain compensation adjustments that I discuss below. The Company has also experienced other price increases for necessary products and services. The Company has specifically budgeted in the FTY and FPFTY for needed increases to staffing levels to maintain reliability, regulatory compliance, and continued improvement in several areas, most notably, operations and training. While UGI Gas continues to focus on efficient operations and has seen stable customer growth over time, the Company's forecasted increases in operating and capital costs, along with experienced and anticipated changes in per customer usage, will prevent UGI Gas from having a reasonable opportunity to earn a fair rate of return on its investment at present rates.

Specifically, as reflected in UGI Gas Exhibit A (Fully Projected), Schedule A-1, UGI Gas's operations are projected to produce an overall return on rate base of 6.45%, which equates to a return on common equity of only 7.56% for the twelve-month period ending September 30, 2026. As explained by UGI Gas witness Paul R. Moul (UGI Gas Statement No. 6), those returns are inadequate based on applicable financial analysis and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief, those projected returns will continue to decline. This could potentially jeopardize UGI Gas's ability to attract the capital needed to make investments that support operating a safe and reliable distribution system and enhance the reach and capacity of facilities that are required for system growth. Moreover, with its requested rate relief, UGI Gas will have the opportunity to earn a sufficient return on investments needed to continue replacing older, more risk prone facilities, systems, and equipment, each of which is necessary to ensure continued system reliability, safety, and customer service performance.

Q. Has the Company evaluated the impact of its proposed rate increase on average customer bills generally?

A. Yes. As shown in Table 1, below, the Company has evaluated the impact of its proposed rate increase on the average monthly bill of residential heating, commercial heating, and industrial customers.[1]

Table 1 – Average Customer Bill Impact

	Usage	Current	Proposed	Change	% Change
Residential Heating	73.7 ccf	$ 104.47	$ 115.74	$ 11.27	10.8%
Commercial Heating	28.3 Mcf	$ 305.44	$ 331.80	$ 26.36	8.6%
Industrial	75.4 Mcf	$ 765.99	$ 823.42	$ 57.43	7.5%

The average customer monthly bill impacts set forth in Table 1, above, are fair and reasonable because UGI Gas will utilize the increase in distribution rates to support its ongoing provision of safe and reliable distribution service for its customers. As detailed below, even with this increase, UGI Gas will continue to have distribution rates that compare favorably to other Pennsylvania natural gas distribution companies ("NGDCs") on a total bill basis, inclusive of natural gas costs. The proposed customer charges also reasonably reflect cost-of-service principles, while considering the rate design principle of gradualism.

Q. What other key proposals are included in this general rate increase filing?

A. UGI Gas proposes in this proceeding to complete the transition to uniform distribution rates for Rate DS across the former North and South/Central Rate Districts, an effort proposed

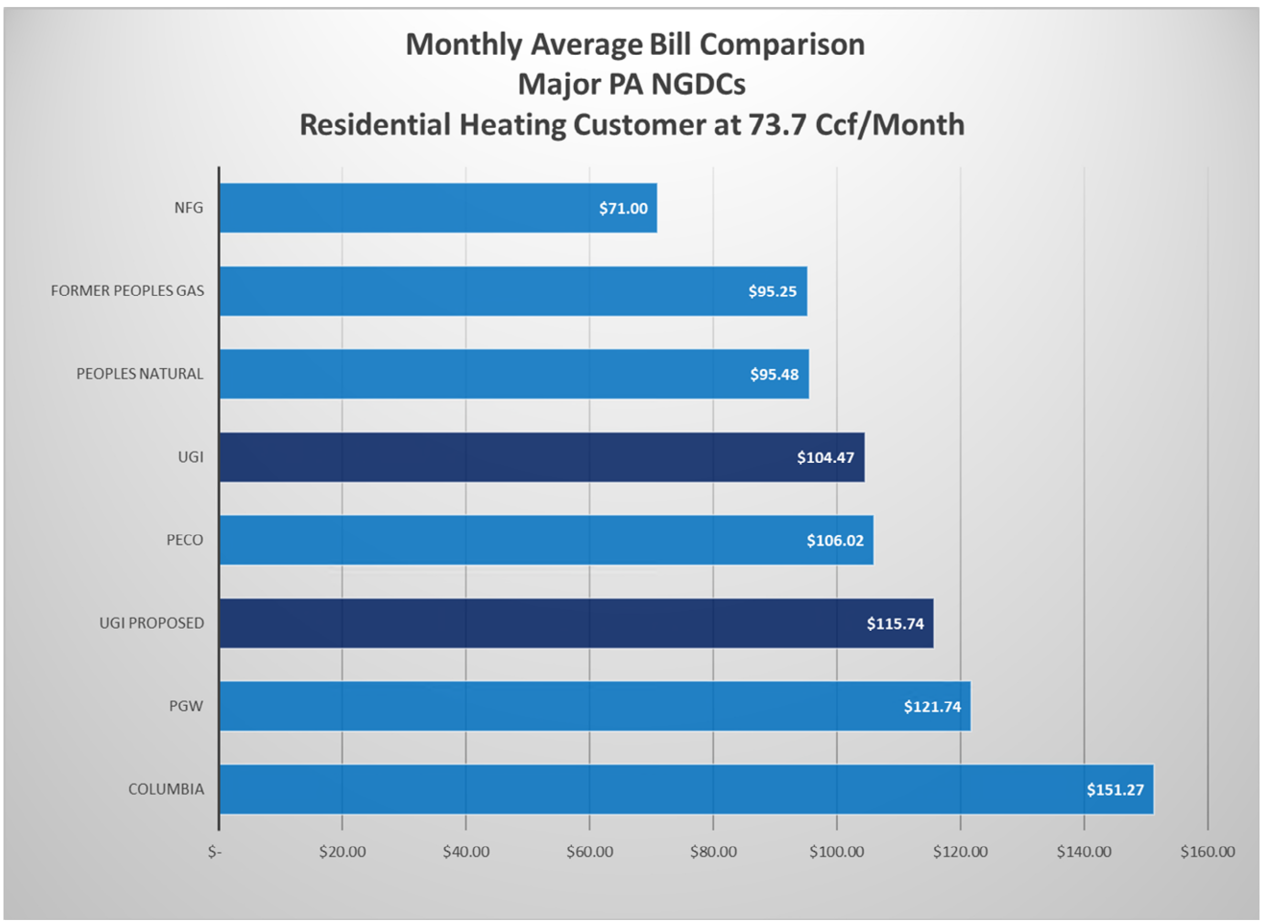
[1] Current bills are based on rates in effect as of December 1, 2024, and reflect gas commodity being purchased from UGI Gas.

but not completed as part of the Company's 2019, 2020, and 2022 rate cases. This proposal is discussed in more detail in the testimony of John D. Taylor (UGI Gas Statement No. 10).

Q. How do UGI Gas's rates compare with other Pennsylvania utilities?

A. A comparison of average residential heating bills, shown in Table 2 below, illustrates that UGI Gas's current distribution rates compare favorably to the rates of other major NGDCs in the Commonwealth, and will remain so, even at the full increase of proposed rates.

Table 2 – Residential Heating Distribution Rate Comparison



In considering UGI Gas's overall rates, it is also important to note that the Company continues to maintain a natural gas supply portfolio that is designed to maximize the benefits associated with the Commonwealth's shale gas supply resources. Also, the Company continues to support the development of environmentally beneficial gas sources. In addition to the Company's initial renewable natural gas ("RNG") interconnect, UGI Gas now has completed two other interconnects, permitting RNG to be utilized by numerous customers as part of their supply elections and the Company's supply portfolio. RNG stands to provide numerous benefits to the natural gas industry and its consumers as related to the provision of lower-carbon solutions that can be readily integrated into existing natural gas systems. Even with the rate changes proposed in this proceeding, the average residential heating customer bill will be 14% lower than it was in 2008 when natural gas commodity prices were materially higher. In summary, UGI Gas offers excellent service to customers at reasonable rates.

Q. When does the Company anticipate that it will file its next base rate case?

A. UGI Gas anticipates that it will be filing another rate case approximately one year following the filing of this base rate proceeding, as significant capital investment amounts similar to those projected for the FPFTY are projected to continue and will drive the need for additional timely rate relief.

IV. COMPENSATION ADJUSTMENTS

Q. Is the Company making any adjustments to its original FPFTY budget as related to Salaries and Wages in this filing?

A. Yes, the Company recently initiated a compensation benchmarking review of salaries and wages in order to assess the Company's market competitiveness related to compensation for numerous positions within the organization. The compensation benchmarking was completed by Willis Towers Watson ("WTW"), an industry expert that regularly provides these services to companies such as UGI. The WTW review served to identify numerous positions which currently fall below desired competitive levels for compensation, both in terms of base compensation and bonus incentive compensation.

Q. What adjustment is the Company proposing to the original FPFTY budget as related to Salaries and Wages?

A. As discussed in further detail below, the total annualized salary and wage adjustment related to benchmarking adjustments is $5.399 million, inclusive of related benefit costs of 12% ($4.813 million base compensation and $0.586 million bonus incentive compensation). Of this amount, $2.397 million will impact operating expense. Accordingly, Schedule D-9 for the FPFTY incorporates an adjustment for the operating expense impact of this unbudgeted adjustment of $2.397 million ($2.106 million base compensation and $0.291 million bonus incentive compensation).

Q. Please describe the specific needs which are being addressed by the compensation adjustments that the Company has included in this filing.

A. UGI's benchmarking activity is critically important to the Company's ongoing efforts to attract, recruit, train and retain those professional, technical and field-qualified personnel and resources necessary to implement, operate, and maintain a safe and reliable natural gas distribution system for all customers. The market has shown robust labor demand as evidenced by employee turnover metrics, with recent year turnover continuing at high levels. In fact, like many companies in the current labor market, UGI has experienced an increase in voluntary employee turnover, as the available labor market has become constrained and increasingly competitive. This is particularly true for roles that require experienced employees. As a result of the current job market, more employees, including those with years of regulated utility experience, are moving on to other opportunities outside of UGI Gas, or moving out of the workforce via retirement. From Fiscal Year 2023 to Fiscal Year 2024, voluntary exempt turnover increased from 7.6% to 8.4%.

In some instances, the Company encountered difficulties finding internal interest for certain critical exempt positions, evidencing a need to address relative compensation levels across expected career pathways to assure effective progressions occur for those with appropriate qualifications. For instance, experienced non-exempt employees (e.g., long term field employees) with advanced classifications in operations possess key experience and knowledge requirements necessary to fill exempt supervisory roles. From a compensation competitiveness standpoint, such exempt supervisory roles must be established at a compensation level which reflects that pay for a non-exempt supervisory role, including overtime and other pay premiums, will be lost when transitioning to an exempt supervisory role. Overall, the purpose of implementing all of the proposed salary and wage adjustments is to improve UGI Gas's ability to: (1) retain existing experienced employees; (2) continue employee development and advancement; and (3) compete for qualified employees to fill needed roles in a very competitive job market.

Q. Please describe the basis for the compensation benchmarking adjustments that the Company is making in this case.

A. WTW reviewed current exempt and non-exempt employee compensation levels against benchmark data provided by two primary surveys: (1) the 2024 Willis Towers Watson American Gas Association Compensation Survey (44 participants); and (2) the 2024 Willis Towers Watson Energy Services Middle Management and Professional Services Survey (164 participants). These surveys were utilized to perform position matching, compensation comparisons and quantification of adjustments where position compensation was found to be behind market, both in terms of base and bonus compensation amounts. Additionally, on an individual employee level, compensation was reviewed for appropriate relationship to midpoint compensation targets. More specifically, WTW performed an independent review and analysis of the Company's pay structure and salaries compared to industry-specific benchmark surveys and then compared current individual employee compensation levels to the survey midpoints by role, or other survey data where a job match could not be identified utilizing WTW's industry-specific data. The use of the midpoint survey data comports with the Company's goal to establish compensation at the fiftieth percentile level. Additionally, time in position was used to create a target salary at various service levels and link with those relative targets to the midpoint of the salary recommendations. A mapping of this data for specific position incumbents then determined which specific employees warranted adjustments (i.e., less than 3-5 years of service would fall in relative target increments against the midpoint market compensation levels).

Q. Can you please provide the summary detail of the *base* compensation benchmarking adjustments?

A. Yes, the chart below outlines the number of employees affected by the base compensation adjustments, by functional department and details operating expense impacts related to the base adjustments and associated bonus incentive compensation impacts of these changes based on the employees' position grade level and predetermined time allocations as related to FY2026, or the Company's FPFTY period. The total annualized salary and wage adjustment related to these base compensation benchmarking adjustments is $4.813 million, inclusive of related benefit costs of 12%. Of this amount, $2.106 million will impact operating expense. Consequently, Schedule D-9 for the FPFTY incorporates an adjustment for the operating expense impact of this unbudgeted adjustment of $2.106 million.

Table 3: Base Compensation Benchmark Adjustment Impacts by Functional Department

	Count of Employee Adjustments	Base Compensation Change Impact (FPFTY)	OPEX Impact of Change (FPFTY)	Bonus Impact Related to the Base Change (FPFYT)	Opex Bonus Incentive Impact of Base Change (FPFTY)
Accounting, Bldg & Grounds, Business Support Services, Claims, Finance, Fleet	11	$ 78,457	$ 19,758	$ 5,747	$ 1,339
Capital Planning, Capital Project Management, Capital Construction, Corrosion Control, Damage Prevention, Dispatch, Leak Survey, Meter Shop, M& R Support, Operations, Stores	169	$ 1,970,884	$ 865,317	$ 138,498	$ 68,295
Engineering, GIS, Telemetry, Standards and Materials	90	$ 844,118	$ 132,138	$ 79,193	$ 14,376
Customer Care	37	$ 206,905	$ 172,824	$ 15,266	$ 13,013
HR, IT	30	$ 253,096	$ 161,070	$ 31,526	$ 18,026
Community Relations, Sales & Marketing	31	$ 191,035	$ 80,785	$ 19,283	$ 8,143
Procurement, Rates, Supply	22	$ 150,226	$ 123,348	$ 14,615	$ 11,349
Business Process Improvement, Project Team, Safety, Training	24	$ 273,657	$ 173,118	$ 25,142	$ 17,353
Total	414	$ 3,968,377	$ 1,728,359	$ 329,270	$ 151,895
Benefit Gross-up (12%)		$ 4,444,582	$ 1,935,762	$ 368,782	$ 170,123

Q. Can you please provide an explanation and summary detail of the *bonus incentive* compensation adjustments for certain roles?

A. Yes, in addition to the base salary review, WTW performed a market analysis on the Company's target bonus incentive compensation levels. In this regard, WTW compared the Company's bonus incentive plan and plan levels to industry market data by position and identified several areas where the Company's bonus incentive compensation was behind market for bonus incentive compensation. WTW considers target bonus percent levels to be competitive if they fall within plus or minus 5 percentage points from market levels; thus, the identified and included adjustments relate to those positions falling outside of that range. Accordingly, in addition to base salary adjustments, the Company plans to increase the target bonus incentive for two of the Company's grade levels. One grade level is currently 7.5% and will move to 10% (impacting 96 employees), and the second grade level is currently at 10% and will move to 15% (impacting 30 employees). The total annualized salary and wage adjustment related to these base compensation benchmarking adjustments is $0.585 million, inclusive of related benefit costs of 12%. Of this amount, $0.291 million will impact operating expense. As such, Schedule D-9 for the FPFTY incorporates an adjustment for the operating expense impact of this unbudgeted adjustment of $0.291 million. Overall, these changes align employee efforts with industry market levels and serve to provide safe and reliable service to the Company's customers, support high levels of customer service, and contribute to workforce recruitment and retention.

Q. Please describe the timing for the compensation benchmarking adjustments that the Company is making in this case.

A. The analysis was completed by WTW and presented to the Company in November 2024. UGI Gas continues to perform an ongoing review of the analysis results, given that the results are detailed at the individual level for factors such as time-in-grade and internal equity among positions and may be subsequently subject to various refinement. Base salary increases have begun where finalization is complete with the remaining adjustments expected to be completed by September 2025. Bonus incentive compensation adjustments are being finalized, and communication of these changes is scheduled to be complete by March 2025.

Q. In addition to the salary and wage increases discussed above, is the Company's claim in this case subject to further updates related to compensation, in particular as related to upcoming collective bargaining contracts that will expire during the FTY?

A. Yes, UGI Gas has begun negotiations on the Company's largest union contract, with ratification expected to be finalized in March 2025. While the Company has included a budget estimate for this increase in labor costs in the FTY, once the contract is finalized, the budgeted increase will be updated to reflect the actual contract value as part of the Company's rebuttal testimony along with appropriate annualization of the impact related to the FPFTY.

V. CYBERSECURITY AUDIT ADJUSTMENT

Q. Please describe the biennial cybersecurity audit adjustment in Schedule D-12 of UGI Gas Exhibit A – Fully Projected.

A. As part of UGI's comprehensive approach to cybersecurity, it is moving forward to adopt a biennial cybersecurity audit. Such an audit is currently an industry best practice and is now a requirement for Maryland utilities, including UGI Gas. The estimated cost of this biennial audit is $250,000; as such, Schedule D-12 of UGI Gas Exhibit A – Fully Projected includes an adjustment of $125,000 to reflect the annualized cost impact of this new cybersecurity best practice.

VI. <u>COMPETITIVE CUSTOMER ANALYSIS</u>

Q. In the 2019 Base Rate Case settlement, the Company agreed to prepare a competitive alternative analysis for each interruptible customer with alternate fuel capability, starting in 2020 with updates every five years; has the Company prepared such an analysis consistent with the next five-year update?

A. Yes, it has. In accordance with Paragraph 73 of the 2019 Base Rate Case settlement, the competitive alternative analysis includes twelve (12) months of historical usage, the date the analysis was completed, and a reasonable proxy cost on an equivalent BTU basis the customer would incur to utilize the alternative fuel based on published index prices for the alternative fuel. The competitive analysis for each customer also includes a listing of actual interruptions with dates and duration. As the analysis contains highly confidential customer information, the Company will make it available to the statutory advocates during the discovery process in accordance with and subject to the provisions of a stipulated protective agreement or protective order.

VII. <u>MANAGEMENT EFFECTIVENESS AND PERFORMANCE</u>

Q. What actions has UGI Gas taken that reflect superior management performance?

A. UGI Gas has focused on a number of areas to enhance and improve the quality and effectiveness of its service in recent years that reflect superior management performance. These management efforts include: (A) investments in safety; (B) infrastructure improvements made pursuant to the Company's LTIIP; (C) excellent customer service; (D) low-income assistance through the Company's Universal Service programs; (E) community engagement; (F) IT modernization; (G) environmental initiatives; (H) diversity and inclusion; (I) research and development; and (J) cost optimization.

A. Investments in Safety

Q. Please describe the Company's investments in Safety Culture Development and Training.

A. The Company's standardized approach to training and safety culture, in particular, its development of a comprehensive and centralized training center ("Learning Center") and creation of a safety and health management system, ensures that all Company employees share common values regarding safety and are trained in a consistent manner throughout the Company's service territory. UGI Gas maintains a culture that drives employees to perform their day-to-day responsibilities with a high degree of safety. In September 2021, the Company implemented a robust telematics and in-cab driver coaching system for all drivers of Company vehicles and provides supervisory coaching of events triggered by the system, along with positive recognition of safe defensive driving maneuvers. In FY2023, UGI Gas also incorporated the American Petroleum Institute ("API") Recommended Practice 1173, as a focus to improve pipeline safety and integrity. Additionally, in FY2025, the Company is introducing a focus on High Energy Hazard Assessment and Energy Control. These programs are discussed in further detail in the Direct Testimony of Christopher R. Brown (UGI Gas Statement No. 9).

The Company also has several ongoing safety initiatives. UGI's "Making a Difference by Living Our Values" Incentive Program rewards employees who demonstrate positive safety behaviors. Additionally, UGI Gas has implemented a "Near Miss/Good Catch" program, which seeks to proactively prevent safety incidents by learning from issues that had the potential for, but did not result in, damage or harm. Vendor safety is monitored through ISNetworld, which is vendor safety software to qualify contractors and monitor their performance trends. This data is compared against the Company's safety standards to ensure the contractors are qualified to perform work for the Company. All of these programs ensure UGI Gas is providing safe, reliable service to the communities it serves. In fact, in FY2024, the Company achieved its best ever Occupational Safety and Health Administration ("OSHA") Recordable Incident Rate ("RIR").

B. Infrastructure Improvements

Q. What infrastructure improvements has the Company achieved?

A. As further explained in the testimony of Christoper R. Brown (UGI Gas Statement No. 9), UGI Gas has an accelerated infrastructure replacement plan focused on replacing all remaining cast-iron and bare steel mains. UGI Gas is a leader in the Commonwealth, with the highest percentage of contemporary mains among major NGDCs at almost 90%. The Company projects that it will eliminate all cast-iron mains by 2027 and all bare steel mains by 2041. The Company's infrastructure improvement statistics, exemplified by the reduction of leaks and cast iron breaks discussed in Mr. Brown's testimony, is a direct result of this accelerated infrastructure replacement plan. During the five-year term of its Second LTIIP (2020-2024), UGI Gas invested approximately $1.3 billion in infrastructure improvements, building off an already-successful LTIIP that has realized material reductions to the number of hazardous and non-hazardous leaks. Additionally, on August 16, 2024, the Company filed its Third LTIIP (2025 – 2029), with anticipated spending of an additional $1.7 billion on infrastructure improvements. This Third LTIIP will see UGI Gas complete its cast iron replacement, advance bare steel replacements, and incorporate the replacement of certain priority plastic pipe. The Commission entered an Order approving the Third LTIIP on December 5, 2024, at Docket No. P-2024-3050769.

C. Excellent Customer Service

Q. Please describe the Company's achievements in providing superior customer service.

A. Providing superior customer service is a core value that UGI Gas continually seeks to achieve. Notably, the Company has been recognized by Escalent, a top data analytics and advisory firm with extensive energy, utility and brand experience, as a 2024 Customer Champion for continuing to build engaged customer relationships. The distinction is part of Escalent's Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential study, which tracks the performance of 142 utilities and is published twice a year. According to the report, Customer Champions outperform the industry average in several attributes, including building goodwill within their local communities, effectively communicating with customers about system improvements, and offering effective programs including energy savings. These attributes exemplify the Company's superior customer service.

The Company also routinely measures customer satisfaction through several different surveys throughout the year, including: (1) transactional surveys after interactions with customer service representatives; (2) pulse surveys at various points during the customer onboarding process; and (3) opportunities to provide feedback on the Company's public-facing and authenticated web pages. The Company uses feedback from these surveys to identify and address opportunities to improve customer experience.

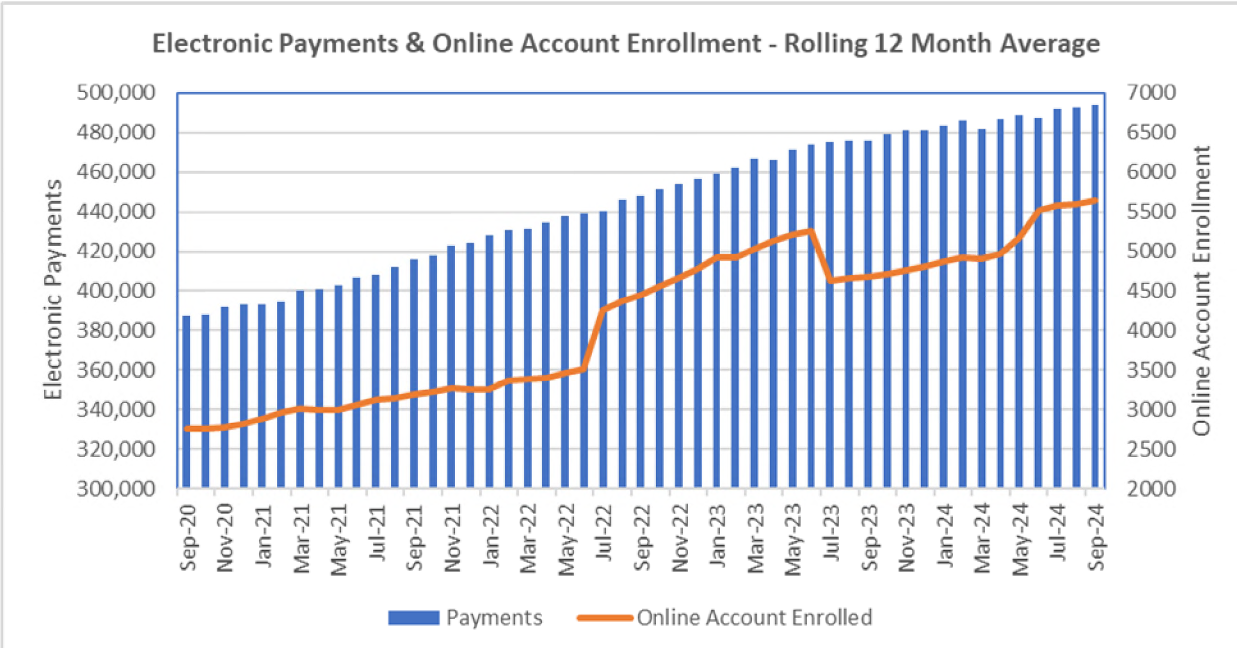
For example, numerous initiatives were put in place to improve first-call resolution and reduce wait times for customers calling the Company's call center to speak to a customer service representative. In February of 2023, the Company partnered with an additional third-party to support move-in, move-out and change of customer calls. This contractor began assisting with customer calls in May of 2023, and along with an additional third-party partnership that has been in place since 2017, the Company has been able to leverage this support as needed to better manage and diversify staffing requirements across multiple sources.

The Company also remains focused on our recruitment, on-boarding, and retention of high-quality Customer Care Representatives ("CCRs"). In 2022 and 2023, market studies and rate adjustments were implemented, which resulted in an average increase of $1.85/hour for the Company's CCRs. Beginning in 2023, an incentive plan was rolled out for CCRs to encourage exemplary performance. CCRs continue to receive regular, on-going support from our Call Center supervisory team, as well as the Company's Training and Quality Assurance departments. The Company provides frequent opportunities for refresher training, and all CCRs participate in a continuous training program that allows them to build on their skills and learn new skillsets. As a result of these efforts, the Company has seen a decreased CCR turnover rate. For FY2023, the total CCR turnover rate was 38%; by the end of FY2024, the CCR turnover rate dropped to 29%. Additionally, scores on 'ease of reaching a representative' on a post-call transactional survey improved nearly one point, up from 7.8 to 8.6 out of 10, over the same fiscal years. Similarly, the percentage of customers stating their service-related issues were resolved in one call increased from 45% in FY2023 to 58% in FY2024. These efforts have also resulted in a significant improvement with UGI's Grade of Service ("GOS"), which is the percentage of calls answered in under 30 seconds. The marked improvement resulted in year over year improvements from a GOS of 73% in FY2022 to 80% in FY2023 and 83% in FY24. These metrics demonstrate the results of the Company's efforts to focus on continuing to improve and deliver exceptional customer service.

Additionally, customers who self-serve via the Online Account Center are significantly more satisfied because of the Company's new and improved Online Account Center, which launched in December 2023 and improved the functionality and usability of the Company's customer payment portal. Hundreds of customers have taken the time to share their comments on how easy the site is to use and shared their appreciation for UGI's dedication to making the experience easier. As a result, customer satisfaction scores for the Online Account Center significantly improved in FY2024, resulting in an almost 2-point increase in satisfaction scores; moving from a 6.5 in Q1 to an 8.4 in Q4 where on a scale of 1 – 10, 1 is very dissatisfied and 10 is very satisfied.

As of November 8, 2024, there are 419,153 registered profiles in the UGI Online Account Center, and 343,448 accounts are receiving paperless bills. Over the last five years, as shown in Table 4, both the average number of monthly electronic payments received and the average number of newly registered online accounts have increased significantly. On average, monthly electronic payments have increased by over 100,000 per month, recently passing the 500,000 milestone, which accounts for 76% of all payments received. Additionally, the monthly average number of newly registered online accounts is around 5,500, doubling the figures we saw in late 2020.

Table 4 – Electronic Payments & Online Account Enrollment – September 2020 – September 2024



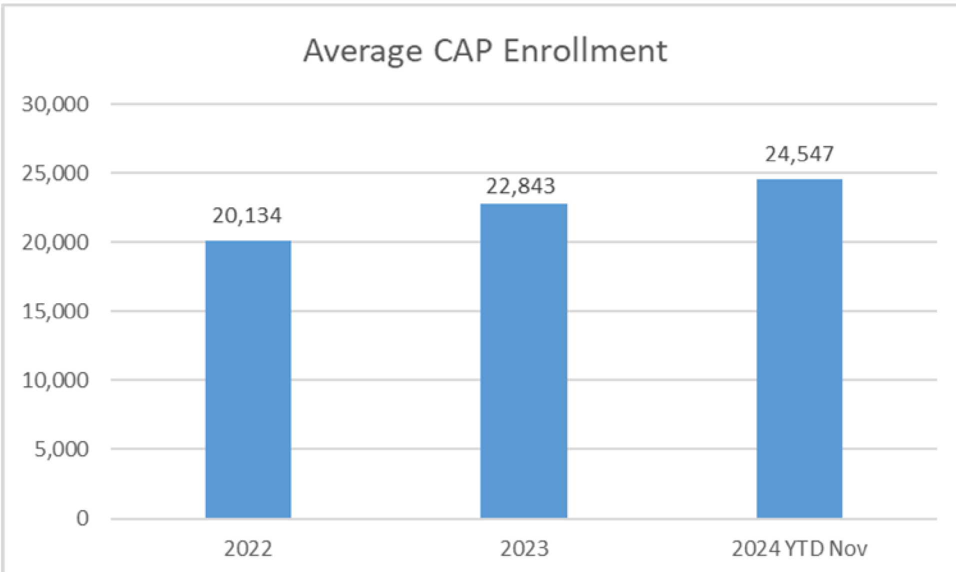
D. Universal Service Programs

Q. Please describe the Company's achievements with its Universal Service Programs.

A. UGI's Universal Service Programs have shown steady growth over the last few years. In particular, the LIURP budgets have been effectively spent, as UGI has worked closely with its weatherization Contractors and Community Based Organizations ("CBOs"). As illustrated in Table 5, Customer Assistance Program ("CAP") enrollments have continued to see a steady upward trend due to UGI's continued marketing efforts that include twice a year outreach (email, direct mail) to customers who are self-reported low income and to LIHEAP recipients that are not currently enrolled in CAP. In addition, the Company recently completed an initiative to assess and engage potential low-income customers to encourage enrollment in the Company's CAP, resulting in over 500 customer enrollments. The Company also began participating in the Pennsylvania Department of Human Services

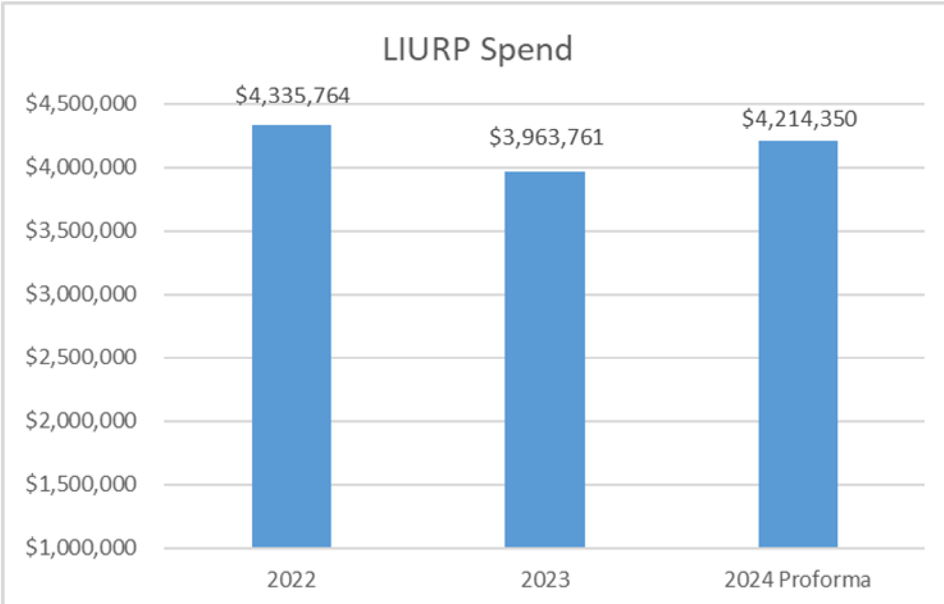
("DHS") LIHEAP data sharing initiative in October 2024 and is working to actively promote the availability of CAP to those customers who received LIHEAP that the Company was not aware of due to customers applying for LIHEAP through their other utility providers.

Table 5 – Average CAP Enrollment (2022 – 2024)



For LIHEAP, the Company successfully facilitated the processing of nearly 26,000 grants for $10.1 million during the 2023-2024 season. Additionally, UGI Gas customers benefitted from over 2,300 Operation Share grants accounting for over $850,000 in assistance during Fiscal Year 2024. The Company's annual LIURP spending from 2022 – 2024 is shown in Table 6. The Company continues to maximize spend in relation to Universal Services Energy Conservation Plan approved budgets.

Table 6 – Annual LIURP Spending (2022 – 2024)



The Company expects participation in its Universal Service Program to continue to grow as marketing efforts continue through various channels, including email, social media, direct mail, and SMS texts for customers who opted in to receive text messages. The Company's Customer Outreach Team also hosts Winter Assistance Relief Mobilization ("WARM") events at its partner CBOs to assist customers on a one-on-one basis and provide enrollment in programs that benefit customers.

E. Community Engagement

Q. Please describe the Company's community engagement efforts.

A. Each year, UGI invests more than $1.0 million, through the Department of Community and Economic Development's Education Improvement Tax Credit Program, to support 90+ education improvement programs across the Company's service territory. UGI's community efforts are focused in four key areas: Improving Literacy, Inspiring Future STEM Professionals, Building Future Leaders, and Supporting Safe and Sustainable

Communities. By focusing on these four areas, UGI can make a concentrated, impactful investment today for the next generation and future potential workforce.

UGI has been partnering with the national nonprofit, Reading is Fundamental, to support early literacy efforts for 33 years. Literacy skills are a critical foundation for success in school and life, and UGI is dedicated to improving literacy and providing greater access to books to students across the Company's service territory. During the 2023-2024 school year, 28,000 books were distributed to 12,600 first-grade students in 71 schools. In celebration of National Reading Month, three randomly selected schools also won STEM book collections, containing 100 books each to be used in their classrooms or distributed to students.

UGI also began initial work with The Energy Innovation Center Institute ("EICI"), an independent 501(c)(3) organization whose mission is to help solve the world's most intractable problems by transforming how humans learn and work in more sustainable and resilient ways. EICI is the program arm of the Energy Innovation Center, and its charter places preeminence on helping those in the most vulnerable populations throughout the Appalachian Region. EICI seeks to break cycles of poverty by connecting the stranded talent in regional disadvantaged communities to the highroad jobs around them and to which they are often excluded.

As an energy provider, UGI relies on professionals with STEM skills to deliver safe and reliable energy to our customers. It is vitally important for UGI to continue pursuing innovation and ensure there are talented people to drive this innovation. During the 2023-2024 school year, UGI partnered with Science Explorers and the S.P.A.R.K.S. Foundation to deliver hands-on science experiments and demonstrations to 3,318 elementary students in 27 schools across the Company's service territory.

The foundation of a strong community rests on people having stable access to affordable housing, food, and safe and healthy environments. One of UGI's main partnerships to support safe and sustainable communities is with the American Red Cross. UGI is proud to support the "Sound the Alarm" Campaign, which has saved more than 2,063 lives and installed over 2.7 million smoke alarms nationwide. In 2023, UGI's support helped install 9,335 smoke detectors across the Company's service territory through the Sound the Alarm Campaign. In addition, UGI distributed donations totaling $10,000 to volunteer fire departments and another $10,000 in donations to food banks in 2024.

Furthermore, UGI's employees are eligible for 16 paid hours of volunteer time per year per the Company's volunteer policy. As of November 2024, year to date, employees logged just over 2,600 volunteer hours participating in Company-organized volunteer initiatives. In the annual community relations survey, nearly 700 UGI employees self-reported over 42,000 hours of volunteer service. UGI employees also donated personal funds to support and improve their communities. More than 1,000 employees contributed a total of more than $320,000 to 170 community organizations as part of the Company's 2024 UGIVE Employee Giving campaign. Combined with corporate contributions, scheduled for payment in January 2025, and retiree contributions, total support provided to United Way agencies serving communities in the UGI service territory in 2024 will total more than $512,000.

F. Information Technology Modernization

Q. Please describe the Company's efforts at modernizing processes and Information Technology.

A. The Company is building on its past focus on distribution system modernization by taking advantage of newer technologies, equipping employees for future success, and improving organizational communication. The centerpiece of the Company's IT modernization is UNITE, a multi-phased series of projects to identify and address business and technology opportunities for improvement. The Company has completed multiple UNITE phases to date and is presently engaged in a current-state analysis review of the Company's asset management processes. This effort will modernize and harmonize the Company's IT systems.

Q. Please explain the improvements that the Company has made as part of UNITE.

A. Through the UNITE program, the Company has made significant technology improvements. In 2017, the Company replaced its Customer Information System. Since then, the Company continually has enhanced this solution to gain operational efficiencies and deployed a Customer Portal to further enhanced customer experience.

In 2019, the Company replaced its Enterprise Resource Planning ("ERP") solution and its fixed asset accounting solution and introduced a contractor billing solution. Since then, internal controls were enhanced through the increased use of electronic purchase orders (about 74% of all purchases in fiscal 2024) as well as automated wire payments, approval routings, and user access provisioning. Over 67% of purchase orders correspond to contractor activities invoiced via the contractor billing solution, with workflow to ensure only Company validated invoices matching a purchase order and within the project budget are automatically processed for payment. Lastly, the Company's use of electronic fund transfer methods (i.e., ACH, wire, or direct debit) reached 98% in Fiscal Year 2024.

In 2020, the Company deployed a Capital Budgeting and Forecasting solution integrated with the Company's ERP and with the Fixed Asset and Tax solutions. This solution embedded lifecycle governance for approving and monitoring capital projects, improved visibility of capital expenditure requests and authorized capital projects, detailed forecasting for more accurate tracking of ongoing capital projects, and improved data analytics for making timely and optimal capital decisions.

In 2023, UGI deployed the Asset Data Collection ("ADC") solution, which focuses on the identification and standardized capture of asset data information across UGI. Through this solution, the Company deployed to field personnel more effective, user-friendly tools to vie and to collect data on assets, such as as-built sketches. This enhanced mobile functionality results in a more accurate and complete capture, track, and trace of asset data.

Q. Please describe the UNITE current state analysis of the Company's asset management processes.

A. In 2024, the Company moved forward with initial work on a field service management ("FSM") project focused on replacing the current outdated field software system solution and supporting an advanced planning, scheduling, and dispatch of field work via mobile field interface that will integrate directly with the Company's existing UNITE programs. The FSM program is described further in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

Q. What processes are being evaluated in the next UNITE projects?

A. In the next phases of the UNITE program, the Company will focus on several projects to support various aspects of enterprise asset management ("EAM"). Specific to the gas utility operations, the processes in scope of this current state analysis include: (1) main replacement, distribution system reinforcement, and line extension projects; (2) service installations; (3) new and upgraded regulator stations; (4) inspections, maintenance, and other repairs; (5) paving and restoration; and (6) facility location and damage prevention.

Q. What will be the focus of the UNITE EAM initiative in the FPFTY?

A. The Company has begun work targeting the Field Service Mobility portion of EAM with a goal of placing that program in service in July 2026. The EAM program is described further in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

G. Environmental Initiatives

Q. Please describe the Company's engagement on environmental initiatives.

A. The Company, as well as its parent UGI Corp., are committed to environmental stewardship. The Company worked with UGI Corp. to publish its sixth annual Sustainability Report for FY2023, which – among other initiatives – tracks progress against a number of goals associated with emissions reductions, the development of renewable energy sources, spend commitments associated with diverse suppliers, safety priorities, and the governance of the Company's programs.

Q. What actions has UGI Gas taken to address environmental stewardship?

A. Since 1995, the Company has successfully converted almost 128,000 households, mostly from fuel oil to more environmentally-friendly natural gas. UGI Gas also encourages energy efficiency through its voluntary Energy Efficiency and Conservation ("EE&C") programs. Dating back to inception, the EE&C programs have also worked to reduce both customer natural gas and electric consumption by over 1.3 million Mcf and 24,108 MWh, respectively. With regard to large industrial customers, UGI Gas supplies natural gas to facilities that, in part, have enabled the Commonwealth to substantially lessen its reliance on electric generation produced by more carbon-intensive fuels, such as coal and oil. Additionally, UGI Gas maintains an environmental permitting program that operates to ensure that gas main and other construction projects are properly designed, permitted, and constructed to mitigate potential erosion and discharge of sediments to watersheds. UGI Gas also manages a program under a Consent Order and Agreement ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP") to actively investigate and remediate potential impacts to the public or the environment associated with the historic operation of manufactured gas plant ("MGP") sites. Finally, UGI Gas is actively implementing options that reduce its carbon footprint, including the continuation of a program that incorporates RNG into its distribution system and gas supply portfolio, and the introduction of equipment at regulator stations that lowers or eliminates emissions associated with control valves and odorization infrastructure. During FY2024 and FY2025, the Company also initiated a significant advanced mobile leak detection ("AMLD") pilot program that surveyed nearly 100 miles of mains and associated distribution system infrastructure. AMLD expansion is further discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 9), along with quantification of related cost adjustments.

Q. What efforts has UGI Gas made toward sustainability?

A. UGI Gas continues to increase its focus on sustainability as it pertains to the natural gas industry. To support the expansion of sustainability overall, the Company maintains its memberships with the American Biogas Council, a national natural gas trade organization that represents the entire U.S. biogas industry and focuses on maximizing the production and use of biogas from organic waste; and the NextGenGas Coalition, a collaborative effort to facilitate external engagement and educational opportunities to accelerate the successful advancement of the NextGenGas marketplace. Additionally, UGI Gas recognizes that a more fuel-efficient fleet can contribute to sustainable operations and currently has 216 compressed natural gas ("CNG") fueled vehicles as part of its fleet, with plans to add approximately 45 to 50 more and a CNG fueling station in Middletown by the end of the FPFTY. These fleet CNG conversions provide significant reductions in carbon emissions. The Company's cast iron and bare steel replacement activities also have resulted in lowering methane emissions. Based on the pace of replacement projects, it is forecasted that the replacement and betterment programs will be completed in advance of the 2027 and 2041 targets for cast iron and bare steel, respectively. Additionally, in November 2022, UGI assembled a cross-functional Methane Emissions Tracking Committee ("METC") that brought together Company subject matter experts from Engineering, Operations, Pipeline Safety Management, Safety, Metering & Regulation, Capital Construction, Standards, and Sustainability to identify all first party (i.e., scope 1) carbon emissions and define process for procuring data and estimating the volume of greenhouse gases associated with the recognized sources. The METC project was completed near the end of calendar year 2023 and culminated in the publication of an internal Company recommendations report that identified the following opportunities:

- Further investigation of AMLD technology as it relates to UGI Gas's distribution system.
- Establishment of a formal evaluation program for both novel and traditional emissions quantification and mitigation technologies.
- Retention of the largest-volume scope 1 emission sources to explore for mitigation opportunities.
- Development of a unified compliance strategy for rulemakings focused on emissions accounting and reporting.

The Company plans to continue to enhance and expand its initiatives aimed at lowering methane and greenhouse gas emissions through the development of a new cross-functional team formulated in the first quarter of 2024 – the Sustainability and Innovation ("S&I") Team.

Q. Please detail the Company's efforts to comply with the United States Environmental Protection Agency's ("EPA") Subpart W/Greenhouse Gas Reporting Program ("GHGRP") regulations.

A. UGI Gas submits timely regulatory filings by March 31 for the prior calendar year to comply with EPA's Subpart W/GHGRP requirements for the distribution industry segment. These filings contain information on scope 1 fugitive emissions associated with Company mains, services, and regulator stations. UGI Gas also performs leak surveys using optical gas imaging ("OGI") technology at approximately 20% of the roughly 200 regulator stations that are classified as above ground Transmission-Distribution ("T-D") Transfer Stations under the EPA rule. In April 2024, EPA published an amended final rule that will largely go into effect in calendar year 2025. UGI Gas has been taking steps to prepare for the regulations' implementation, which include new source reporting requirements, and requirements to quantify emissions during leak surveys or develop facility-specific emission factors. UGI Gas's efforts in this regard are further discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 9).

H. Diversity and Inclusion

Q. What actions has UGI Gas taken to address diversity and inclusion?

A. UGI Gas is committed to fostering a more diverse and inclusive work environment, which will provide a stronger and more cohesive workforce that ultimately provides improved service to our customers. As part of this focus, UGI has implemented a Belonging, Inclusion, Diversity and Equity ("BIDE") initiative. BIDE was formed in 2020 to enhance and expand UGI Gas's efforts to be "part of the solution" in addressing systemic bias and injustice in the communities in which it operates. Utilizing the Company's values – safety, integrity, respect, responsibility, reliability, accountability, and excellence – UGI Gas has implemented steps to model inclusive leadership and provide a culture in which employees feel a sense of belonging. To effectively implement the objectives of BIDE, UGI Gas has created a council that includes senior leadership dedicated to increasing inclusivity and diversity in four core pillars of the business: Culture, Career, Community, and Commerce. The BIDE Council's mission is to cultivate an inclusive and equitable workplace where employees feel a profound sense of belonging, promoting equity and diversity as fundamental principles that enhance the Company's business success and community impact to attract, retain, and develop a more diverse team at UGI Gas.

Q. What resources has the BIDE initiative provided to UGI employees?

A. As part of its focus on creating a culture of inclusion, UGI's BIDE Council has developed three employee resource groups: Black Organizational Leadership and Development ("BOLD"), Women's Impact Network ("WIN"), and the Veteran Employee Team ("VET"). BOLD focusses on inclusion, equity, education, and empowerment for black employees and will assist leadership with communication, talent recruitment and retention, and promotion for black employees. BOLD drives professional development through mentoring and sponsorship opportunities, increasing exposure through networking and career development events. It also promotes cultural transformation by influencing Company policies and procedures that can improve an employee's experience at UGI, as well as the impact these policies and procedures have on customers and partners. WIN fosters an environment for women to be recruited, retained, developed, and advanced as leaders within the UGI Family of Companies. Membership in WIN offers exposure to various professional development opportunities, including speaker series events, group engagement activities, virtual group discussions, and partnerships with local organizations. VET recruits and retains veterans and fosters goodwill towards veterans. Members include Active Duty, Reserve, and National Guard veterans of the Army, Navy, Marines, Coast Guard, and Air Force, their families, and partners committed to supporting military veteran employees. These three groups provide support, mentorship, educational opportunities, advocacy, and events to increase awareness and involvement and to grow the culture of inclusion at UGI Gas. New for 2025, within the context of BIDE, is the creation of a group-wide Employee Engagement Committee and a Partnership Committee. The Employee Engagement Committee's purpose is to: (1) plan and coordinate group wide employee engagement initiatives/themes across UGI Gas; (2) ensure alignment and coordination of all local employee engagement activities; and (3) share ideas and best practices across UGI Gas. The Partnership Committee's purpose is to: (1) develop a Charitable Giving Policy that aligns with the Company's mission and core values; (2) create UGI Charitable Giving Guidelines including the operational process, procedures, and ownership responsibilities; (3) provide ongoing support to UGI charitable initiatives to maximize community benefits and business impacts; and (4) periodically assess partnership relationships to assure alignment with policy objectives and guidelines.

Q. What additional actions has UGI Gas taken as part of its BIDE initiative?

A. In addition to employee resource groups, UGI Gas has continued to refine its efforts to hire and retain diverse employees, including more senior level positions. This effort includes consideration of a diverse slate of candidates for all director level or higher roles. BIDE has also incorporated UGI's long-time focus on developing relationships with diverse suppliers and vendors. The Company has continued its efforts to contract with Minority, Women and Disabled Owned Businesses ("Diversity Spend"). Historically, UGI has acquired diverse supply partners through various methods. The Company has implemented employee education and training, utilized the support of relevant database tools, incorporated diverse vendors into its requests for proposals ("RFP"), and provided guidance on entering into agreements with diverse outfits.

Since the launch of the Procurement Supplier Diversity Program in 2021, Procurement has exceeded annual goals aimed at increasing the inclusion of diverse vendors. An initial Company goal was established to increase spend with diverse vendors by 25% by 2025. This goal was accomplished by September 2023, with UGI Gas's total spend on diverse vendors exceeding $175 million since the launch of the program in 2021.

In 2024, UGI Gas's total supplier diversity spend exceeded $57 million. UGI is also a proud sponsor of the National Minority Supplier Development Council ("NMSDC"), providing access to a network of certified minority business enterprises and demonstrating the Company's commitment to economic equity.

I. Research and Development

Q. Please describe the Company's research and development plans.

A. UGI Gas will begin work with the Gas Technology Institute's Operations Technology Development ("OTD") program starting in the FTY. OTD allows utilities to combine interests, expertise and resources into focused R&D projects. OTD's research projects focus on improving the safety, reliability, and operational efficiency of natural gas projects. This program will support access to best practices related to key areas of research information and support investments in ongoing areas of focus which are of material interest to UGI Gas in support of the ongoing efficient maintenance and operation of a safe and reliable distribution network. In addition, it will support research for newer or emerging gas technologies. These programs will benefit the Company's customers by enhancing efficient operational and equipment standards to support safe, reliable delivery of natural gas.

J. Cost Optimization

Q. Please describe the cost optimization program which the Company recently implemented.

A. During Fiscal 2024, the Company planned and implemented a program designed to optimize operational processes, reduce costs, and improve cash flow currently and into the future. The program included re-thinking the Company's organizational structure and processes, considering optimization for current and future efficiency. In connection with this program, the Company identified approximately $13,500,000 of annualized cost savings, which benefit Fiscal Year 2024 and future years.

Q. What was the nature of the savings identified under this program?

A. The savings identified under this program included personnel savings (including elimination of open positions); incremental capitalization of certain costs (most significantly insurance premiums); and savings from reductions within the following areas: (1) professional fees; (2) third party administrative support; (3) sponsorships and memberships; (4) IT software and hardware; (5) telephone services; (6) customer program notifications; (7) office supplies, travel costs, and activities; (8) training; (9) materials; (10) donations; (11) publications; (12) building maintenance and landscaping; and (13) marketing.

Q. Did UGI Corp. participate in the cost optimization program?

A. Yes. UGI Corp. identified personnel and non-personnel savings in the areas of Finance, Human Resources, IT, Legal and Procurement. Of these savings, approximately $2,800,000 of annualized savings funneled to UGI Gas through the cost allocation process.

Q. How much did the Company incur to implement this savings program?

A. During Fiscal Year 2024, UGI Gas incurred approximately $2,800,000 of one-time costs to implement this savings program. These costs are included in the HTY results but are not part of the claim in this rate case.

Q. How did the cost optimization program benefit the Company's ratepayers?

A. Ratepayers benefit from cost savings through lower impacts to rates, all else being equal. Ratepayers will continue to benefit from a more optimized cost structure and process efficiencies that were introduced as a part of this program.

Q. What do the Company's efforts in the above-referenced areas demonstrate?

A. UGI Gas believes that the management efforts described above, and the other improvements described by the UGI Gas witnesses in this proceeding, as well as the Company's provision of safe and reliable service at reasonable rates, demonstrate UGI Gas's commitment to safety, community partnership, and the provision of excellent customer service. In total, these efforts support an additional upward adjustment of 0.20% to the Company's equity return in recognition of its management effectiveness, which is included in the 11.2% equity return requested in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT HGB-1

Hans G. Bell

Summary

Proven Energy Utility Executive with 29 years of gas & electric utility leadership experience including P/L accountability, transmission and distribution operations, engineering, asset integrity management, rate case / regulatory strategy, capital program management, customer service, and business development.

Experience

UGI Utilities, Inc., Denver, Pennsylvania

Utility President accountable for all aspects of business performance to ensure safe, reliable, and cost-effective natural gas & electric service for a utility serving more than 700,000 customers. Over a 12-year tenure at UGI Utilities, led the establishment of long-term infrastructure investment programs, led a 4-fold ramp up in capital investment to achieve infrastructure replacement objectives, developed internal & external capabilities and resources to execute the program, and guided the strategies needed to achieve return on investment. Consistently led team to deliver on key metrics including safety, reliability, customer service, and financial objectives.

President, UGI Utilities, Inc. *2020-present*

- Accountable for accountable for delivering overall business performance to ensure safe, reliable, and cost-effective natural gas and electric utility service
- Provides executive leadership for organization comprised of ~1,700 personnel including executives, technical professionals, and line workers engaged in gas & electric operations, engineering, financial management, rates, gas supply, environmental health & safety, capital program management, construction, and IT system implementation
- Delivers presentations to Board of Directors to secure approval of long-term strategy, annual plan, and major investments
- Maintains relationships among regulators, elected officials, customers, and trade allies
- Presents Utility segment business updates at investor conferences and meetings with shareowners

Chief Operating Officer *2017-2020*

- Consistently delivered upon increasing annual infrastructure replacement plans – on-time and on budget pipeline replacement program for 6 consecutive years
- Developed & implemented sustainability strategies into the business, including establishing methane emission reductions and integration of renewables and energy efficient technologies
- Implemented a safety culture enhancement program and initiated a Pipeline Safety Management System implementation plan
- Led delivery of a $70M pipeline of 10 miles x 24” pipeline, to serve major power plant, now UGI’s single largest customer
- Primary author of the UGI Long-Term Infrastructure Improvement Plan – a 5-year investment plan and strategy encompassing more than $1.25 Billion of safety & reliability improvements
- Achieved safety & reliability improvements including 27% reduction in hazardous leaks, 75% reduction in leaks scheduled for repair, 36% reduction in cast iron main break frequency, and consistent performance in excavation damage prevention

Vice President, Engineering and Operations Support *2013- 2017*

- Accountable for accelerated infrastructure replacement programs, capital budgeting contractor management, corrosion control, damage prevention, employee safety, engineering design, transmission & distribution integrity, regulatory compliance, training, and all related technical support functions.
- Accountable for planning and execution of annual cast iron / bare steel replacement program covering > 64 miles per year
- Primary author & regulatory witness for Long Term Infrastructure Improvement Plans, and annual asset optimization plans
- Primary witness providing written and verbal testimony to secure and increase the UGI Distribution System Improvement Charge which accelerated intra-rate case recovery of major safety & reliability investments
- Responsible for management and development of professional and technical support staff of over 110 employees
- Managed regulatory compliance activities with the PA Public Utilities Commission – Pipeline Safety Division

Nicor Gas, Naperville, Illinois

Over 17 years at Nicor Gas, a 2.1M customer gas utility, advanced through positions of increasing responsibility beginning at entry level through Managing Director of Engineering. During the AGL / Nicor merger served as functional lead for engineering & technical support on the merger integration team.

Managing Director, Engineering *2012-2013*

- Accountable for Engineering Design, Land Management, and System Planning supporting gas transmission, storage, and distribution operations spanning 11 states serving over 4.5 million customers
- Managed capital budgets of >$200M including budget development, variance reporting, and project prioritization
- Accountable for oversight of right of way acquisitions in advance of major pipeline projects
- Developed long term investment plans for infrastructure replacement, optimization, and growth

Assistant Vice President Engineering & Chief Engineer *2011- 2012*

- Accountable for all gas utility engineering support departments with over 50 professional and technical staff including Engineering Design, Transmission Integrity, Distribution Integrity, System Planning, Geographic Information Systems, Measurement, and Technical Services (Lab)
- Accountable for Transmission & Distribution Integrity Management compliance, audits, plans, program management, and project portfolio optimization.
- Accountable for Engineering Design and project management for distribution, storage, and transmission projects from initial scope, detailed design, cost estimates, sourcing, and contract negotiation
- Managed multiple interdisciplinary project teams executing complex multi-million-dollar storage and transmission projects
- Managed regulatory relationships with State (ICC) and Federal Pipeline Safety Agencies (PHMSA). Provided technical support to incident investigations
- Developed strategic approaches to addressing pipeline safety legislation including MAOP affirmation
- Developed engineering integration plans for AGL Resources– Nicor Gas merger including, organizational design, critical process mapping, accountabilities, budgeting, and staffing

General Manager System Integrity & Chief Engineer *2007 - 2011*

- Responsible for management of multiple departments including Engineering, Transmission Integrity, Distribution Integrity, System Planning, and Geographic Information Systems
- Responsible for development and management of infrastructure capital budgets of approximately $65 million
- Managed contracts with engineering consulting firms for pipeline design, construction, survey, and professional services
- Implemented a Distribution Geographic Information System including database design, data conversion of over 34,000 miles of distribution pipe, and deployment of a mobile GIS application to all front-line workers

Manager Engineering Design *2004- 2007*

- Responsible for managing departmental capital budget in excess of $20 million annually
- Provided project management oversight to pipeline projects from concept, feasibility, budgeting, approval, planning, design and implementation
- Maintained engineering consultant relationships and negotiated service contracts
- Implemented process improvements including development of Geographic Information System (GIS) based map distribution application
- Managed pipeline construction projects, negotiated construction contracts, resolved permitting issues, and delivered project approval presentations

Project Manager – Transmission Pipeline Integrity *2003 –2004*

- Responsible for development and implementation of pipeline integrity management program to maintain regulatory compliance with the Pipeline Safety Act of 2002
- Developed risk management program for prioritization of pipeline integrity assessments in high consequence areas
- Determined pipeline assessment project schedules including long term operating expense and capital budgets

Region Manager – Distribution *2001 – 2003*

- Manager responsible for construction and maintenance activities of gas distribution utility
- Managed projects involving main installations, service installations, and leak repairs
- Measured and tracked performance of 50 personnel against productivity and safety benchmarks
- Coordinated response to emergencies including gas leaks and pipeline breaks

Supervisor of Distribution Planning *2000 - 2001*

- Supervised staff of six engineers in distribution planning department
- Coordinated hydraulic modeling studies of 34,000-mile natural gas distribution system serving over 2 million customers
- Recommended capital improvement projects required to maintain uninterrupted reliable peak day service throughout entire natural gas distribution network
- Coordinated long range planning studies and forecasts used to develop capital budgets

Project Engineer *1996 –2000*

- Managed pipeline construction and maintenance projects, supervised inspectors and company maintenance crews
- Designed plans for installation and revision of gas distribution facilities
- Reviewed highway improvement plans and worked with state transportation engineers to resolve utility conflicts

Professional Activities & Affiliations

- Licensed Professional Engineer, State of Illinois, License # 62054443
- Director, Pennsylvania Chamber of Business & Industry 2023-present
- Director, Northeast Gas Association 2018- present (Chair 2025)
- Member, Society of Gas Operators – 2015 to present
- Member, Society of Gas Lighters – 2018 to present
- American Gas Association Bronze Award of Merit 2012
- Member, American Gas Association Leadership Council
- Chair, American Gas Association Distribution & Transmission Engineering Committee 2012 - 2013
- Co-chair of Southern Gas Association Distribution Engineering Committee 2007-2010

Education

Keller Graduate School of Management, Chicago, Illinois

Master of Business Administration*, Graduated with Distinction, 2000*
Concentration in Finance

University of Illinois, Champaign, Illinois

Bachelor of Science in Civil Engineering*, 1996*
Concentration in Construction Management

Wharton School, University of Pennsylvania, Philadelphia, Pennsylvania

Executive Development Program, 2017

Previous testimony before the Pennsylvania Public Utility Commission at Dockets:

P-2013-2398833 UGI Utilities, Inc. – Gas Division, Long Term Infrastructure Improvement Plan

P-2013-2398835 UGI Central Penn Gas Inc., Long Term Infrastructure Improvement Plan

P-2013-2397056 UGI Penn Natural Gas, Inc. Long Term Infrastructure Improvement Plan

R-2015-2518438 UGI Utilities, Inc. – Gas Division, Base Rate Case

R-2018-3006814 UGI Utilities, Inc. – Gas Division, Base Rate Case

UGI GAS STATEMENT NO. 2

TRACY A. HAZENSTAB

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Gas Utilities, Inc. – Gas Division

Statement No. 2

Direct Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Revenue Requirement** **Operating Revenues and Expenses** **Compliance with Act 40 of 2016**

Dated: January 27, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Sr. Manager – Utility Rates. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Sr. Manager - Utility Rates?

A. I am primarily responsible for various tariff filings and related computations for UGI Gas and UGI Electric rate and regulatory filings before federal and state regulatory commissions. As part of these responsibilities, I am responsible for preparing and supporting the Company's revenue requirement models for this base rate filing, which is included as UGI Gas Exhibit A. I report directly to the Chief Regulatory Officer of UGI.

Q. What is your educational background?

A. Please see my resume, UGI Gas Exhibit TAH-1, which is attached to my testimony.

Q. Please describe your professional experience.

A. Please see my resume, UGI Gas Exhibit TAH-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. Attached to my direct testimony is UGI Gas Exhibit TAH-1, which contains a list of proceedings in which I previously testified. Additional exhibits that I am sponsoring are described below.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's proposed revenue requirement. First, I provide an overview of the Company's revenue requirement exhibits for the historic year ended September 30, 2024 ("HTY"), future year ending September 30, 2025 ("FTY") and the fully projected future test year ending September 30, 2026 ("FPFTY") (Section II). Second, I present UGI Gas's ratemaking presentation for the FPFTY, including its revenues and operating expenses claims, and certain pro forma adjustments (Section III). The Company's rate proposal in this case is predicated on its FPFTY exhibit, which demonstrates the need for a revenue increase of $110.395 million. I also address the Company's compliance with Act 40 of 2016 (Section IV).

Q. What exhibits are you sponsoring in this proceeding?

A. In addition to UGI Gas Exhibit TAH-1 mentioned above, I am sponsoring UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Historic). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing.

II. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS

Q. Please describe the principal accounting exhibits used to support UGI Gas's claims in this proceeding.

A. UGI Gas Exhibit A (Fully Projected) provides the calculation of the revenue requirement for the FPFTY, including principal accounting exhibits, rate base claims, revenue at present rates, operating expense claims, taxes and certain *pro forma* adjustments. The FPFTY information is derived from UGI Gas's operating and capital budgets for the 12-month period ending September 30, 2026. UGI Gas Exhibit A (Future) is the principal accounting exhibit for the FTY, including certain *pro forma* adjustments. The FTY information is derived from UGI Gas's operating and capital budgets for the 12-month period ending September 30, 2025. UGI Gas Exhibit A (Historic) is the principal accounting exhibit for the HTY, with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-month period ended September 30, 2024. The future and historic schedules are provided as a benchmark for comparison with the FPFTY claim, which, as explained above, is the basis for UGI Gas's proposed revenue increase of $110.395 million.

Q. Please provide an overview of UGI Gas's principal accounting exhibits.

A. As noted above, UGI Gas's claims in this case are based on UGI Gas Exhibit A (Fully Projected). This presentation is comprised of four sections:

<u>Section A</u> summarizes UGI Gas's requested *pro forma* rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.

Section B includes basic accounting data extracted from UGI Gas's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing UGI Gas's embedded cost of debt, year-end capital structure and overall claimed rate of return.

Section C provides the elements of UGI Gas's rate base claim and how each element of that claim is derived. UGI Gas's rate base includes utility plant in service, gas storage inventory, cash working capital, materials and supplies inventory, and offsets for accumulated depreciation, accumulated deferred income taxes, and customer deposits.

Section D presents UGI Gas's revenues and expenses on a *pro forma* ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting FPFTY expense and revenue levels are shown on Schedule D-3 and were used to establish UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

Q. What information is included in UGI Gas Exhibits A (Future) and A (Historic)?

A. UGI Gas Exhibits A (Future) and A (Historic) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2025, and the fiscal year ending September 30, 2024, respectively. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing the FPFTY claims with actual and projected results from the FTY and HTY.

Q. What are the data sources for the UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic)?

A. This data is derived from UGI Gas's books and records as well as its capital and operating budgets. UGI Gas Exhibit A (Future) is based on adjusted budgeted data for the FTY. UGI Gas Exhibit A (Historic) is based on adjusted experienced data for the HTY.

III. REVENUE REQUIREMENT FOR THE FULLY PROJECTED FUTURE TEST YEAR

Q. How is your discussion of UGI Gas's FPFTY revenue requirement presentation organized?

A. In Section III.A., I present a summary of UGI Gas's FPFTY revenue requirement. In Section III.B., I discuss UGI Gas's proposed rate base. In Section III.C., I explain the determination of UGI Gas's revenues and operating expenses, depreciation, taxes other than income taxes, income taxes, and the gross revenue conversion factor.

A. FPFTY REVENUE REQUIREMENT SUMMARY

Q. How were the *pro forma* revenue increase and total revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 4, of UGI Gas Exhibit A (Fully Projected). Lines 1-9 summarize the *pro forma* measure of value (rate base). Lines 10-19 show the following items at present rates: *pro forma* revenues, *pro* *forma* expenses, taxes, taxes on the revenue increase, *pro forma* net operating income, and the calculated rate of return. Lines 20-23 show the increase in net operating income required to permit UGI Gas to earn the claimed overall rate of return of 8.42%. Application of the Gross Revenue Conversion Factor establishes the revenue increase shown on line 25 needed to generate the change in operating income. Column 4 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 8.42%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $110.395 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $1.251 billion and the annual level of operating revenues of $1.141 billion under existing rates. These figures are shown on line 13 of Schedule A-1 of UGI Gas Exhibit A (Fully Projected).

B. FPFTY RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI Gas rate base values for the FPFTY. Column 1 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim is $4.003 billion. Please see the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3) for a discussion of the rate base components.

C. FPFTY REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the roll-in of revenues from the Distribution System Improvement Charge ("DSIC"), and other *pro forma* annualizing and normalizing ratemaking adjustments. The net effect of these adjustments is shown in UGI Gas Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 8).

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to operating expense claims.

A. UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2026. Section D of UGI Gas Exhibit A (Fully Projected) presents UGI Gas's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the appropriate test years ending

September 30, 2025 and 2024, respectively. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with prior results.

1. Summary

Q. Please describe Schedule D-1 of UGI Gas Exhibit A (Fully Projected).

A. Schedule D-1 presents a summary income statement that includes UGI Gas's claimed gas revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of Sherry A. Epler (UGI Gas Statement No. 8) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $110.395 million on line 4 in column 2.

Q. What is the level of net income at proposed rates?

A. As shown on column 3, line 21, net income at proposed rates is $337.094 million. This represents a $78.843 million increase from the level under current rates ($258.251 million), as shown on line 21 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12-month period ending September 30, 2026. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-2, column 3?

A. Yes. The derivation of the various column 3 revenue adjustments is included in UGI Gas Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-13, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on lines 1-5 of Schedule D-3. Gas cost revenue adjustments for each customer class are shown on lines 6-10 and details of other revenue adjustments are shown on lines 11-13 of Schedule D-3. Details for each revenue adjustment are shown in Schedules D-5 (including supporting Schedule D-5A) and are discussed in the direct testimony of witness Sherry A. Epler (UGI Gas Statement No. 8). Another revenue adjustment, shown in Schedule D-5B, is sponsored by Darin T. Espigh (UGI Gas Statement No. 7). This adjustment, in the amount of $795,000, represents the amortization of the CIAC Tax Gross Up Regulatory Liability for interconnects. Regarding *pro forma* expenses, the derivation of the various adjustments is summarized individually on pages 1-2 of Schedule D-3, lines 16-55. The details for these adjustments are found in Schedules D-6 through D-31 and are sponsored by multiple witnesses, as described in the Table of Contents of UGI Gas Exhibit A (Fully Projected) and as listed on the header of each schedule.

2. Operating Expense

Q. How were the claimed operating expenses for the FPFTY determined?

A. *Pro forma* FPFTY expenses are based on the budgeted level of expenses as a starting point. The budgeted data, by FERC account, was then adjusted consistent with generally accepted ratemaking principles to reflect a normal, ongoing level of operations. Schedules supporting those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D.

Q. Were each of the *pro forma* adjustments reflected on Schedule D-3 also charged to an appropriate FERC account?

A. Yes. Each *pro forma* adjustment was calculated and then distributed to FERC accounts directly and presented on Schedule D-3 by major FERC account category.

Q. Schedule D-3 to UGI Gas Exhibit A (Fully Projected) shows an adjustment to Gas Costs in column 4. Please discuss this adjustment.

A. The detail for this adjustment is shown in Schedule D-6. This adjustment is designed to increase purchased gas cost expense by the same amount of the gas cost revenue adjustment contained in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 8) and as shown on Schedule D-5, column 4, lines 7-12. UGI Gas recovers its purchased gas costs on a dollar-for-dollar basis with no profit through an automatic adjustment clause mechanism pursuant to Section 1307(f) of the Public Utility Code. Therefore, the increase in purchased gas costs of $8.114 million equals the increase in gas cost revenue as detailed by Ms. Epler. Thus, with this adjustment, purchased gas cost expense has no effect on the revenue requirement calculation.

Q. Please discuss the Salaries and Wages adjustment shown on Schedule D-7 in the amount of $966,000.

A. Schedule D-7, Column 4, shows a $966,000 increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 of Schedule D-7 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized employees that will take place during the FPFTY. Schedule D-7, page 2, line 2 reflects the increased percentages for each classification of employee. Lines 3 through 5 indicate the percentage of the year for which the salary and wage increases are not reflected in the budget.

Q. How did you determine the split of the budgeted salaries among the various employee classifications shown on Schedule D-7?

A. The split of the budgeted salaries among the various classifications shown on Schedule D-7, page 1, was determined using the allocations of labor and headcount for Operating and Maintenance expense in the budget. These employee groupings are the same groupings utilized in developing the labor budget. These categories were used in UGI Gas's budgeting process for the operating expense portion of salaries and wages.

Q. Are there other salary and wage adjustments shown on Schedule D-7?

A. Yes. Schedule D-7 (Column 2, Line 16, Page 1) shows a total adjustment to salaries and wages in the amount of $2.140 million for a compensation benchmarking adjustment. The detail for this adjustment is presented on Schedule D-9 and aligns salaries for specific positions with relevant industry pay-scales. This adjustment is discussed in more detail in the direct testimony of Hans G. Bell (UGI Gas Statement No. 1).

Q. What adjustments are shown on Schedule D-8?

A. Schedule D-8 represents an adjustment in the amount of ($6.119) million for environmental remediation expense. The adjustments are described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please describe the salary and wage adjustments shown in Schedule D-9.

A. These salary and wage adjustments are discussed in the direct testimony of Hans G. Bell (UGI Gas Statement No. 1) and relate to compensation adjustments the Company is making as a result of a recent compensation benchmarking review. The $2.397 million adjustment on Schedule D-9, Column 3, line 5, reflects an incremental increase in salary, bonus, and benefit costs. The Company calculated the Benefits component (Schedule D-9, Column 2, lines 1 - 4) by applying 12% to the Compensation Benchmark Adjustment Subtotal (*i.e.*, 12% x $2,140,414 = $256,850).

Q. Please discuss Schedule D-10, which shows an adjustment for Rate Case Expense.

A. Lines 1 through 4 show the rate case expense that UGI Gas expects to incur in this case of $1.431 million. That amount is then normalized over a one-year period given the anticipated timing related to the next UGI Gas rate case, as discussed in the direct testimony of Hans G. Bell (UGI Gas Statement No. 1). The budgeted amount of rate case expense in the FPFTY was $880,000. The budget was increased by $551,000 as shown in Column 3, line 8 to reflect more current costs.

Q. What is the nature of the adjustments shown on Schedule D-11?

A. Schedule D-11 represents adjustments in the amount of $770,000 for uncollectible expense. The adjustments are described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please explain the adjustment shown on Schedule D-12.

A. Schedule D-12 represents an adjustment in the amount of $250,000 to recover costs incurred to perform the Company's biennial cybersecurity audit. The biennial cost was then normalized over 2 years for ratemaking purposes, making the proforma amount $125,000. The adjustment is explained in further detail in the direct testimony of Hans G. Bell (UGI Gas Statement No. 1).

Q. What is the nature of the adjustment shown on Schedule D-13?

A. Schedule D-13 represents adjustments in the amount of $3.742 million for costs to implement several improvements to the Company's leak survey procedures. These adjustments are explained in further detail in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 9).

Q. Please explain the adjustment in the amount of $3.519 million shown on Schedule D-14.

A. Schedule D-14 represents an adjustment in the amount of $3.519 million for pension benefit expense. This adjustment is described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Injuries and Damages.

A. Schedule D-15 represents an adjustment in the amount of $632,000 for injuries and damages. This adjustment is described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please discuss the Customer Accounts Expense Adjustment on Schedule D-15 in the amount of $1.583 million.

A. The Company is required to pay interest on Customer Deposits that it holds in accordance with its tariff requirements. Further discussion on customer deposits can be found in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service expense.

A. This adjustment normalizes the amount of Universal Services Program ("USP") expense recovered through the Company's USP Rider based on the level of the Universal Service Rider charge effective at the time of the Company's filing in this matter. The USP Rider recovers the Company's Customer Assistance Program ("CAP") Credits, Pre-Program Arrearages, third party administrator expense, LIURP expense, and administrative costs associated with its Project Share program. The Company's claim represents the ongoing normalized level of costs based on anticipated levels of CAP program participation. This adjustment increases the Company's budgeted expense by $5.581 million, to align the expense with the annualized amount of the Company's current USP Rider charge. As the USP Rider is a fully reconcilable rider, the USP adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to USP flows through to the revenue requirement calculation and into net income. Please see the direct testimony of Ms. Epler (UGI Gas Statement No. 8) for additional discussion of the USP Rider.

Q. Please describe the adjustment on Schedule D-17.

A. The adjustment shown on Schedule D-17, Column 2, line 2, in the amount of $494,000 is the annual cost to perform material verification of transmission lines pursuant to pipeline integrity regulatory requirements. This adjustment is explained in further detail in the testimony of Christopher R. Brown (UGI Gas Statement No. 9).

Q. Please describe the adjustment on Schedule D-18.

A. The adjustment shown on Schedule D-18, Column 2, line 6, in the amount of $687,000 is incremental costs for pipeline contractors. These cost increases are based on requests for proposals ("RFPs") for new contractor agreements that will become effective March 1, 2025, and are explained in further detail in the testimony of Christopher R. Brown (UGI Gas Statement No. 9).

Q. Please explain the adjustment for Energy Efficiency and Conservation ("EE&C") Programs shown on Schedule D-19.

A. As with the PGC and USP Rider adjustments discussed above, this adjustment in the amount of $152,000 aligns the amount of EE&C expense with the EE&C Rider charge (based on the level of the EE&C Rider charges effective at the time of the Company's filing in this matter). The EE&C Rider recovers the Labor and Administrative, Prescriptive Program, Retrofit Program, New Construction Program, Custom Program, Legal and Consulting, Combined Heat and Power, and other Costs associated with the Company's Energy Efficiency and Conservation Program. This adjustment increases the Company's budgeted expense to align with the annualized amount of the Company's current EE&C charge. As the EE&C Rider is a fully reconcilable rider, the EE&C adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to EE&C flows through to the revenue requirement calculation and into net income. Please see the direct testimony of Ms. Epler (UGI Gas Statement No. 8) for additional discussion of the EE&C Rider.

3. Depreciation Expense

Q. How was the level of depreciation expense for the FPFTY determined?

A. UGI Gas's depreciation study is set forth in UGI Gas Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Gas Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Gas Statement No. 4).

Q. Please describe the depreciation expense adjustments shown on Schedule D-21.

A. UGI Gas witness Mr. Wiedmayer (UGI Gas Statement No. 4) presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of ($3.679) million set forth on Schedule D-21, page 2, column 3, line 64, annualizes budgeted FPFTY depreciation expense to calculate an entire year's worth of depreciation on plant in service (as of the end of the FPFTY). This schedule also shows a decrease to the net negative salvage amortization of $84,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $157.093 million (as shown on Schedule D-3, page 2, column 13, line 53).

4. Taxes Other Than Income Taxes

Q. Please describe the taxes other than income adjustments shown on Schedule D-31.

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7. This produces an adjustment to the amount of social security, Federal Unemployment Tax ("FUTA") and State Unemployment Tax ("SUTA") expense in the total amount of $248,000. The calculation of these adjustments is shown in more detail on Schedule D-32. The other components of this schedule are supported in the testimony of Darin T. Espigh (UGI Gas Statement No. 7).

5. Income Taxes

Q. What is the purpose of Schedules D-33 and D-34?

A. These schedules show the derivation of the Company's pro forma income tax expense claim, including the normalization of the effects of accelerated tax depreciation, as discussed in the direct testimony of Darin T. Espigh (UGI Gas Statement No. 7).

6. Gross Revenue Conversion Factor

Q. What is the purpose of Schedule D-35?

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Paul R. Moul (UGI Gas Statement No. 6). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue and to recognize the additional state and federal income taxes attributable to the proposed rate increase.

IV. ACT 40 REQUIREMENTS

Q. Ms. Hazenstab, are you familiar with Section 1301.1 of the Public Utility Code, which is otherwise known as Act 40 of 2016?

A. Yes, I am. The legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania. It requires a utility to demonstrate that it shall use at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment to support reliability or infrastructure related to the rate-base eligible capital investment and that the other 50 percent shall be used for general corporate purposes. It is also my understanding that this legislation "shall no longer apply after December 31, 2025," under its own terms. My understanding is predicated in part on the advice of counsel.

Q. Has the Company calculated what would have been the ratemaking level of a consolidated tax savings adjustment for UGI Gas prior to the enactment of Section 1301.1 of the Public Utility Code?

A. Yes, Company witness Darin T. Espigh presents such a calculation in his testimony (UGI Gas Statement No. 7). The Company's three-year average of consolidated taxable income was $116.427 million. Based on Mr. Espigh's calculation of the net positive taxable income of the three merged entities, the amount of consolidated tax savings adjustment applicable to UGI Gas would have been $591,000.

Q. If Act 40 no longer applies as of December 31, 2025, and the Company's claim in this this case is based upon an FPFTY that ends after the date it no longer applies, why is the Company providing this calculation in this proceeding?

A. Based on the advice of counsel, it is also my understanding that Section 1301.1(c)(2) of the Public Utility Code states that Act 40 "shall apply to all cases where the final order is entered after the effective date of this section." Based upon the timing of this case's filing, and the duration of the statutory suspension period applicable to base rate cases, the Commission must issue a final order in this case after the effective date of Act 40 but before its December 31, 2025 expiration date. Due to this timing and the fact that Act 40 will expire during the FPFTY, the Company is providing what would have been the ratemaking level of a consolidated tax savings adjustment for UGI Gas prior to the enactment of Section 1301.1 of the Public Utility Code.

Q. Does the Company's rate base claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount (associated with a consolidated tax savings adjustment) to support reliability or infrastructure related capital investments?

A. Yes, as included in Schedule C-2 and as discussed in the direct testimony of Ms. Schappell (UGI Gas Statement No. 5), UGI Gas's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $316 million and for the FPFTY is $328 million. This expenditure level is greater than 50% of the amount of what would have been the consolidated tax savings adjustment under prior ratemaking principles.

Q. Does the Company's rate base claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount to support general corporate purposes?

A. Yes. The Company's general corporate purpose expense will also exceed 50% of the tax benefit resulting from elimination of the consolidated tax adjustment. Indeed, the Company anticipated an operating expense budget of more than $811 million in operating expenditures to be used to render gas distribution service; 50 percent of the consolidated tax adjustment revenue requirement would equate to only $414,000.

Q. Is the Company's presentation in this filing consistent with the Commission's and the Commonwealth Court's treatment of PA Act 40 of 2016?

A. Yes. The Company's presentation in this filing is consistent with the Commission's determination on PA Act 40 in the UGI Electric 2018 Base Rate Proceeding at Docket No. R-2017-2640058, and the Commonwealth Court's order affirming the Commission's order on appeal.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT TAH-1

Tracy A. Hazenstab
Sr. Manager – Utility Rates

Work Experience:

2024 – Current	Sr. Manager – Utility Rates UGI Utilities, Inc., Denver, PA
2008 - 2024	Rates Analyst – II/Sr/Principal (Progressive Positions) UGI Utilities, Inc., Denver, PA
2004 - 2008	Business Analyst PPL Gas, Lewistown, PA
2001 - 2004	Contact Center Analyst PPL Gas, Lock Haven, PA

Previous Testimony – Pennsylvania Public Utility Commission:

2014 1307(f) Proceeding:	Docket No. R-2014-2543523
2015 1307(f) Proceedings:	Docket Nos. R-2015-2480937, R-2015-2480934
2016 1307(f) Proceedings:	Docket Nos. R-2016-2543311, R-2016-2543314
2018 1307(f) Proceedings:	Docket Nos. R-2018-3001631, R-2018-3001632
2019 1307(f) Proceeding:	Docket No. R-2019-3009647
2019 UGI Electric EEC Phase III Petition:	Docket No. R-2019-3004144
2020 1307(f) Proceeding:	Docket No. R-2020-3019680
2021 UGI Gas Base Rate Proceeding:	Docket No. R-2021-3030218
2022 UGI Electric Base Rate Proceeding:	Docket No. R-2022-3037368
2023 1307(f) Proceeding:	Docket No. R-2023-3040290
2024 UGI Gas EEC Phase II Petition:	Docket No. R-2024-3048418
2024 UGI Electric DSP V Petition:	Docket No. R-2024-3049343
2024 UGI Gas Book 2 Proceeding:	Docket No. R-2024-3048828

Previous Testimony – Maryland Public Service Commission:

Purchased Gas Adjustment/Annual Cost Adjustment Hearing:

2008 Hearing:	Case Number 9511(c)
2009 Hearing:	Case Number 9511(d)
2010 Hearing:	Case Number 9511(e)
2012 Hearing:	Case Number 9511(g)
2014 Hearing:	Case Number 9511(i)
2015 Hearing:	Case Number 9511(j)
2016 Hearing:	Case Number 9511(k)
2017 Hearing:	Case Number 9511(l)
2018 Hearing:	Case Number 9516(a)
2019 Hearing:	Case Number 9516(b)
2020 Hearing:	Case Number 9516(c)

Assisted in Preparing – Pennsylvania Public Utility Commission:

2009 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2008-2079675
2009 UGI Gas Rate Case (former North Rate District):	Docket No. R-2008-2079660
2011 UGI Gas Rate Case (former Central Rate District):	Docket No. R-2010-2214415
2016 UGI Gas Rate Case (former South Rate District):	Docket No. R-2015-2518438
2017 UGI Gas Rate Case (former North Rate District):	Docket No. R-2016-2580030
2018 UGI Electric Rate Case	Docket No. R-2017-2640058
2019 UGI Gas Rate Case	Docket No. R-2018-3006814
2020 UGI Gas Rate Case	Docket No. R-2019-3015162

Education:

B.A. in International Politics, Pennsylvania State University

UGI GAS STATEMENT NO. 3

VIVIAN K. RESSLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 3

Direct Testimony of
Vivian K. Ressler

Topics Addressed:	**Accounting Process and Historic Costs** **Fully Projected Future Test Year Rate Base** **Budgeting Process** **Operating Expense Adjustments** **Capital Treatment of Certain Information Technology Costs**

Dated: January 27, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Director – Utility Financial Planning &Analysis ("FP&A"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Director – Utility FP&A?

A. I have responsibility for UGI's financial budgeting, forecasting and analysis processes. I lead a team of analysts responsible for preparing the annual budget, including obtaining input from operational departments throughout the business. The team also performs analysis of budget to actual variances and completes financial forecasting and modeling to support business decisions. My duties also include the coordination of these functions with UGI's Accounting Department and the UGI Corp. Vice President FP&A Domestic Business Units as well as other finance and accounting personnel at UGI Corp.

Q. Please describe your educational background and work experience.

A. My full educational background and work experience are set forth in my resume attached as UGI Gas Exhibit VKR-1.

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit VKR-1 provides a list of the proceedings in which I have testified.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's rate case accounting methodology and certain operating expense adjustments. First, I will explain UGI Gas's accounting processes, which were used to develop the actual book accounting results, which are the basis for the Company's historic test year ended September 30, 2024 ("HTY") (Section II).[1] Second, I will present the Company's claim for rate base in this proceeding using a fully projected future test year ("FPFTY") methodology (Section III). Next, I will discuss the budgeting process (Section IV) and certain operating expense adjustments (Section V). Finally, I will discuss the Company's accounting for certain Information Technology ("IT") costs (Section VI).

Q. Ms. Ressler, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibits VKR-1 and VKR-2. In addition, I am sponsoring those portions of UGI Gas Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic), which address rate base and certain adjustments to rate base and operating expenses discussed later in my testimony. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

[1] The budgeting process for the future test year ending September 30, 2025 ("FTY") and the FPFTY ending September 30, 2026 are discussed in Section IV of my testimony.

II. ACCOUNTING PROCESS AND HISTORIC COSTS

Q. How are the accounting records of UGI Gas maintained?

A. The accounting records of UGI Gas are kept in accordance with generally accepted accounting principles ("GAAP") and the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts as required under the provisions of 52 Pa. Code § 59.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 59.46.

Q. Are the books and records of UGI Gas subject to audit?

A. Yes. The books and records of UGI Gas are audited by its internal auditors. In addition, UGI Gas's books and records are included in Company-wide audits of UGI, performed by its external auditor (Ernst & Young, LLP thru Fiscal 2024 and KPMG, LLP beginning Fiscal 2025). The Company's books and records are further subject to audit by the PUC.

Q. Do the continuing property records of UGI Gas reflect the original cost value of property?

A. Yes, they do. UGI Gas's plant in service, plant additions, retirements, and book adjustments have been recorded on an original cost basis in accordance with GAAP and the Uniform System of Accounts requirements.

Q. What process does UGI Gas follow to assure that property reflected in its plant accounts is in service?

A. UGI Gas's capital project managers create records that document the costs of projects and/or asset purchases. When a capital project or asset is placed into service, the project manager records the in-service date and the retirement detail for any related assets that are taken out of service. Then, the record is provided to accounting personnel. This information is transferred through accounting entries into the appropriate UGI Gas plant property accounts, subject to review by authorized individuals who approve the entries and further review by internal and external auditors.

Q How was the Company's accounting process used in preparing the Company's filing?

A. The above-described accounting process was used to prepare the principal accounting exhibits that support UGI Gas's claim in this proceeding. As discussed in the direct testimony of Company witnesses Hans G. Bell (UGI Gas Statement No. 1) and Tracy A. Hazenstab (UGI Gas Statement No. 2), the Company's claim is based on the FPFTY. The accounting data for the FPFTY was derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2026, as shown in UGI Gas Exhibit A (Fully Projected). The accounting data for the FTY was derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2025, as shown in UGI Gas Exhibit A (Future). The accounting data for the HTY was derived from UGI Gas's books and records for the 12 months ending September 30, 2024, as shown in UGI Gas Exhibit A (Historic).

III. <u>FULLY PROJECTED FUTURE TEST YEAR RATE BASE</u>

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. It summarizes the UGI Gas rate base values for the FPFTY. Column 1 provides the schedule where the calculations of each of the rate base elements are found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim—net of deductions for accumulated depreciation, accumulated deferred income taxes and customer deposits—is $4.003 billion. Except where otherwise noted, I will describe each of the rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how UGI Gas determined its FPFTY rate base value for net plant in service.

A. UGI Gas's claim for gross utility plant in service represents the sum of the closing plant balances as of September 30, 2024, plus budgeted additions placed in service for the years ending September 30, 2025 and September 30, 2026, less expected FTY and FPFTY plant retirements. The direct testimony of Company witness Vicky A. Schappell (UGI Gas Statement No. 5) discusses the capital addition planning process and the basis for the additions placed in service in the FTY and FPFTY.

UGI Gas's claim also reflects a reduction for accumulated depreciation, which is based on the closing accumulated depreciation balances as of September 30, 2024, plus depreciation expense for the years ending September 30, 2025 and September 30, 2026, less expected FTY and FPFTY plant retirements.

Q. Please describe Schedule C-2 to UGI Gas Exhibit A (Fully Projected).

A. This schedule presents UGI Gas's FPFTY claim of $6.219 billion for used and useful gas gross utility plant in service on page 2, column 2, line 64. That amount is also reflected on line 1 of the measure of value summary on Schedule C-1. Gas utility plant enables UGI Gas to provide safe and reliable gas service to its customers.

Q. Please describe the information included on Schedule C-2, page 3.

A. This information provides a summary of UGI Gas's *pro forma* claim for gross utility plant in service by category. Column 2 shows the FPFTY ending balances based on the placed in-service budget; column 3 shows the net effect of the various plant adjustments, if any; and column 4 provides the adjusted FPFTY plant in service.

Q. What information is included on Schedule C-2, pages 4 and 5?

A. Columns 2 and 3 on these pages show the gas plant in service balances for 2025 and 2026 at the FERC account level, based on the placed in service budget. Column 5 provides the ending FPFTY plant balance at the FERC account level.

Q. Where are plant in service additions shown?

A. Pages 6 and 7 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY and FPFTY) plant in service additions. The Company categorizes plant in service additions by FERC account.

Q. Where are plant retirements shown and how were these retirements projected?

A. Pages 8 and 9 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY and FPFTY) plant retirements. Retirements for most plant accounts were projected by plant account. The Company applied the average retirement rate, as a percent of additions, for the five fiscal years 2020 through 2024, to the FPFTY and FTY plant in service additions. For certain plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired when the vintage is fully amortized.

2. Accumulated Depreciation

Q. Please explain how UGI Gas determined its rate base deduction for accumulated depreciation.

A. UGI Gas started with accumulated depreciation as of September 30, 2024, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Wiedmayer (UGI Gas Statement No. 4), with the underlying FPFTY depreciation analysis provided in UGI Gas Exhibit A (Fully Projected).

Q. Please describe UGI Gas's accumulated depreciation claim.

A. UGI Gas's accumulated depreciation claim is shown on Schedule C-3 of UGI Gas Exhibit A (Fully Projected). This schedule presents the accumulated provision for depreciation as of September 30, 2026, distributed among the various FERC accounts. The total amount for accumulated depreciation, $1.619 billion, is summarized on page 2, column 2, line 64, of this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1 as a reduction to rate base.

Page 3 of Schedule C-3 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Pages 4 and 5 show the details of the accumulated depreciation by FERC account for Fiscal Years 2025 (column 2) and 2026 (column 3) based on budget plus adjustments (column 4), if any, to arrive at the FPFTY balance (column 5). Pages 6 and 7 show the cost of removal by FERC account and pages 8 and 9 show negative net salvage amortization by FERC account. Pages 10 and 11 include the salvage amounts by FERC account. These amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

Q. Please summarize UGI Gas's net in plant in service claim.

A. UGI Gas's net plant in service claim reflects *pro forma* gross utility plant of $6.219 billion at September 30, 2026, less *pro forma* accumulated depreciation of $1.619 billion at September 30, 2026. These amounts are both reflected on the measure of value summary on Schedule C-1.

3. Cash Working Capital

Q. Please explain how UGI Gas determined its rate base value for cash working capital ("CWC").

A. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the payment of cash expenses incurred to provide that service, as shown in Schedule C-1. A detailed analysis of UGI Gas's CWC requirements is provided in Schedule C-4.

Q. Where is the CWC rate base value summarized?

A. The CWC rate base value is summarized at Schedule C-4, page 1. The various components of the working capital claim are listed on this page, along with a reference to the page where the component is further detailed within Schedule C-4.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of UGI Gas's revenue collection lag and overall expense payment lag. The revenue lag is of 56.60 days (line 1). Expense lag days include three categories of annual operating expenses: (1) payroll; (2) purchased gas costs; and (3) other expenses. The expense lag days are shown for each component (lines 3-5), which amount to 25.62 days (line 7). The net lag in the collection of revenue is 30.97 days (line 8). This number is then multiplied by the average daily operating expense balance (line 9) to arrive at a base CWC amount for Operations and Maintenance ("O&M") expense of $54.762 million (line 10). The average daily expense balance of $1.768 million (line 9) is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense, of $645.350 million (line 6, column 2), by the number of days in the year, or 365. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The Company's calculation for the total revenue lag days of 56.60 (line 23) consists of several steps. First, the annual revenue (line 18, column 3) is divided by the average month-end accounts receivable balances for the 13 months ended September 30, 2024 (line

17, column 2). This results in an accounts receivable turnover rate of 9.32 (line 19, column 4), which is equivalent to 39.16 lag days (line 20, column 5) (i.e., 365 divided by 9.32 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to: (1) the 2.23-day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company (appearing on line 21); and (2) the 15.21-day service lag (i.e., midpoint lag factor), which is the time from the mid-point of the service period until the meter reading date (appearing on line 22). This calculation results in a total revenue lag of 56.60 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.4 days) divided by two (i.e., 15.21 days).

Q. How are the payroll expense lag days for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2, with the same bi-weekly pay period. The lag days are calculated based on 14 days in the pay period divided by 2 (for an average) with a 5-day payroll processing time period added, resulting in a 12-day lag period.

Q. How were the lag days associated with the purchased gas costs shown on Schedule C-4, page 4, line 8 calculated?

A. This calculation is shown on page 6 of Schedule C-4 and is based on a review of gas purchases during the 12-month period of October 2023 through September 2024. The total dollar amount of gas purchased during this period was $368.486 million (on line 13, column 2). The average payment lag was calculated by dividing the total dollar days for purchased gas costs (or $9.005 billion) by the total dollar amount of gas purchased (or $368.486 million), which equals 24.44 days (on line 14). The payment lag was determined using the midpoint of the service period for each of the payments and the payment date for each, averaged over the 12-month study period. The 24.44-day lag for purchased gas costs is then brought forward to Schedule C-4, page 4, line 8 and Schedule C-4, page 2, column 3, line 4.

Q. What are dollar days, and how were they used in the CWC calculation?

A. Dollar days are the product of a payment amount multiplied by the number of days between the invoice date or service date and the date that the payment clears the Company's bank. The dollar days calculation is used to calculate a weighted average number of lag days for both purchased gas costs (Schedule C-4, page 6) and general disbursements (Schedule C-4, page 5).

Q. How were the Other O&M Expense lag days, shown on Schedule C-4, page 4, line 22, calculated?

A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over the HTY, as shown in more detail on page 5 of Schedule C-4. A summary list of all cash disbursements, including the invoice date, the amount of the disbursement, the date the payment was made, and the type of disbursement (for capital, commodity or expense), during each of these months was used. As shown on page 5, lines 1-24, columns 1 and 2, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days for expense purchases were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire and Automated Clearing House ("ACH") payments, or (ii) the number of days from the invoice date until check date, plus seven days (representing mail lag) for payments made by check. Disbursements were eliminated if they were included in another calculation (*e.g.*, gas purchases) or were paid for capital items. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 25, resulted in a payment lag for general disbursements of 33.10 days. The lag for general disbursements is then brought forward to Schedule C-4, page 4, line 22 and Schedule C-4, page 2, column 3, line 5.

Q. Please explain how the interest payment amount included on line 2 of Schedule C-4, page 1 was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $0.259 million shown on page 7, line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $8.983 million as shown on page 7, line 9 of Schedule C-4. This amount is then included on page 1, line 2 of Schedule C-4.

Q. How was the tax payment lag for the working capital requirement, shown on line 3 of Schedule C-4, page 1, determined?

A. This calculation is shown on page 8 of Schedule C-4. Separate tax payment lag calculations (for working capital) are made for federal income tax, state income tax, PA Property Tax and Public Utility Realty Tax Act ("PURTA") taxes. Each of these calculations is based on anticipated FPFTY tax payments and an April 1 mid-point of annual service. The result for each of these components is shown and summed in column 10 to derive the net working capital allowance for tax payments of $4.280 million shown on page 8, line 19. This amount is then included on page 1, line 3 of Schedule C-4.

Q. How was the working capital allowance for prepaid expenses, shown on line 4 of Schedule C-4, page 1, derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the 13-month average of actual pre-paid amounts for each month ended from September 2023 through September 2024. The 13-month average of total actual prepaid amounts during that period is $12.668 million shown on page 9, line 18. This amount is then included on page 1, line 4 of Schedule C-4.

Q. What is the total amount of the Company's CWC claim?

A. UGI Gas's claim for CWC is $62.726 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

4. Gas Storage Inventory

Q. Please explain how the rate base value for gas storage inventory was determined.

A. Gas storage inventory represents gas volumes stored in facilities or in storage fields owned by interstate pipeline or storage companies with whom UGI Gas contracts for capacity. As is typical for most natural gas distribution systems, UGI Gas purchases storage gas throughout the year for use primarily during the winter heating season. Specifically, the Company pays its gas storage bills on a monthly basis once the gas is procured in the same way that its pays for gas procured from other sources. Storage inventory is a physical asset that is included in the Company's rate base claim in the same manner as materials and supplies inventory. UGI Gas's claim for gas storage inventory is based on a 13-month average book value for the period ending September 2024 as shown on Schedule C-5. The average monthly gas inventory balance for the FPFTY is $19.462 million, as shown on

Schedule C-5, line 16. This amount is also used in Schedule C-1, line 5 and Schedule A-1, line 5.

5. Accumulated Deferred Income Taxes

Q. Please explain how the rate base value for Accumulated Deferred Income Taxes ("ADIT"), including Excess Deferred Federal Income Taxes ("EDFIT"), was calculated.

A. The Company's determination of its rate base value for ADIT, including EDFIT, is shown on Schedule C-6 and is discussed in the direct testimony of Darin T. Espigh (UGI Gas Statement No. 7). This amount of $687.743 million reduces rate base. This amount is also used in Schedule C-1, line 6 and Schedule A-1, line 6.

6. Customer Deposits

Q. Please explain how the Company calculated the rate base value for customer deposits.

A. Customer deposits offset the need for UGI Gas to provide capital. UGI Gas's claimed offset for customer deposits is based on the average customer deposit balance for the 13-month period ending September 2024.

Q. What is the amount of the rate base offset for customer deposits?

A. The customer deposit offset is $22.616 million, as shown on Schedule C-7, line 16, Schedule C-1, line 7, and on Schedule A-1, line 7.

7. Materials and Supplies Inventory

Q. What is the rate base claim for materials and supplies inventory?

A. UGI Gas maintains various materials and supplies in inventory for use in its operations. The Company's claim for materials and supplies inventory is $31.924 million, as shown on Schedule C-8, line 16, Schedule C-1, line 8, and on Schedule A-1, line 8. This amount is based on the average inventory for the 13-month period ending September 30, 2024, as shown on Schedule C-8.

IV. BUDGETING PROCESS

Q. Please explain UGI Gas's budgetary preparation and approval process.

A. UGI Gas's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Gas Operating Budget for the subsequent two fiscal years begins during the spring, *i.e.*, the budget process for the October 1, 2024 through September 30, 2025 fiscal year (Fiscal 2025) and the October 1, 2025 through September 30, 2026 fiscal year (Fiscal 2026) begins in the spring of 2024, with information being requested and incorporated from all departments. Internal reviews and revisions occur throughout the spring and summer before the final budget for UGI Corporation is approved by the UGI Board of Directors in September – immediately prior to implementing the budget.

The revenue portion of the budget is a joint effort between the Marketing and Financial Planning and Analysis ("FP&A") departments. The Marketing department provides customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, and shifts in type of residence and customer mix. Budgeted usage per customer is developed by application of a two-year regression to historic data and incorporates normal weather on a 10-year basis (with such normal weather period being as defined by UGI Corp. for use in the budget process). The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying appropriate rates for each customer class to budgeted sales volumes, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management. Specific normalizing and annualizing ratemaking adjustments to the budget for presentation of the FPFTY sales and revenue in this filing are discussed in the direct testimony of UGI Gas witness Sherry A. Epler (UGI Gas Statement No. 8).

Concurrently to revenue development, the expense portion of the Operating Budget is prepared. Operating and maintenance expenses are developed by functional managers based upon review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year. The direct expense portion of the Operating Budget is submitted for review and approval by senior management. UGI Gas's direct expenses are then consolidated with allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Gas to develop the budgeted Statement of Operations. Allocated expenses in the Statement of Operations include functions such as accounting, rates, gas supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements.

The final Operating Budget is then submitted to UGI's President for review and approval. After this approval, the UGI budget is submitted to the Chief Financial Officer at UGI Corp. for additional review and approval and is consolidated with the budgets of other operating units of UGI Corp. The President of each UGI Corp. business unit reviews his or her budget with the UGI Corp. Board of Directors and then the UGI Corp. Board of Directors approves the consolidated UGI Corp budget.

Each element of the UGI Gas Operating Budget is formulated by personnel with responsibilities specific to each aspect of the operation. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

In order to prepare the Capital budget, operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described, and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priority, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented, along with the Operating Budget, to senior management in a series of review meetings. This Capital Budget is subject to approval by the UGI Corp. Board of Directors in a manner similar to that described above for the Operating Budget. Additional information concerning the factors considered in establishing the UGI Gas Capital Budget is provided in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

UGI Gas's Operating and Capital Budget processes incorporates two future fiscal years. This allows UGI Gas to utilize the budget as a starting point for its FPFTY rate claim. For example, the Operating and Capital Budget processes that began in the spring of 2024 incorporated information provided by all departments for both Fiscal 2025 and Fiscal 2026.

Q. Please explain how expenses from affiliated companies are treated to develop the budgeted Statement of Operations.

A. UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI also allocates or assigns applicable costs between UGI Electric and UGI Gas. Costs that can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs that cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service. Allocations are made by using a methodology applicable to the cost (*e.g.*, budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by using a formula referred to as the Modified Wisconsin Formula ("MWF") or another reasonable allocation methodology. The MWF or other allocation methodology achieve an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units which benefit from the respective activities. Activity is measured by revenues and O&M expenses. Size is measured by tangible net assets employed (excluding acquisition goodwill) or by gross plant balance.

Q. How is the budget information used to support UGI Gas's requested revenue increase?

A. This budget information is the starting point for UGI Gas's claims and is adjusted as appropriate to reflect certain anticipated changes based on ongoing business activities since the completion of the budgeting process and through application of other appropriate ratemaking principles.

V. OPERATING EXPENSE ADJUSTMENTS

Q. Please describe how the Company's claimed operating expenses were determined.

A. As discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2), the *pro forma* FPFTY expenses were based on the budgeted level of expenses as a starting point. This budgeted level of expenses was then adjusted to comply with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. The supporting schedules for those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D. Below, I will discuss the specific operating adjustments that I am sponsoring, as contained in UGI Gas Exhibit A (Fully Projected), Section D.

1. Environmental Remediation Expenses

Q. What adjustments are shown on Schedule D-8?

A. Consistent with the methodology the Company has used in past rate cases, the first two adjustments shown on Schedule D-8 are designed to reconcile past Environmental Remediation expense rate recoveries with actual incurred costs and to recover a projected annual level of Environmental Remediation expense. These costs are incurred in connection with UGI Gas's obligations under a Consent Order Agreement ("COA") with the Pennsylvania Department of Environmental Protection ("DEP").[2] The third adjustment shown on Schedule D-8 relates to settlement payments negotiated by UGI Gas under certain insurance policies between July 2022 and December 2023. The Company's remediation activities under the COA are discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 9).

Q. Please describe the first Environmental Remediation expense adjustment shown on Schedule D-8.

A. The adjustment (on lines 1 – 6 of Schedule D-8) is intended to provide the Company with normalized ratemaking recovery of ongoing annual cash expenditures primarily to remediate former manufactured gas plant ("MGP") sites in accordance with the COA. Because the amount budgeted is the amount UGI Gas recovered in the most recent previous base rate case, it does not properly reflect the amount that the Company is likely to incur during the FPFTY. Therefore, as in past cases, the Company has chosen to normalize the expenditure based on its recent actual experience.

The average of the last three years of cash expenditures for remediation expenses under the COA is $5.429 million and represents the amount that the Company anticipates that it will spend in the FPFTY under the COA. The difference between this annual amount ($5.429 million) and the amount budgeted by the Company ($5.171 million), or $0.258 million, is the first adjustment.

[2] Effective October 1, 2020, DEP consolidated the Company's prior three COAs (which aligned with the Company's former rate districts) into one COA that covers the entire UGI Gas service territory.

Q. Please describe the second Environmental Remediation expense adjustment shown on Schedule D-8, lines 7 – 11.

A. The second environmental adjustment (on lines 7 - 13 of Schedule D-8) shows the net over-recovery of the Company's MGP remediation expense incurred in past years, and the planned amortization for this net over-recovery. This net over-recovery resulted from the combination of (1) the under-recovery in actual annual remediation costs for Fiscal 2022, Fiscal 2023 and Fiscal 2024 versus the normalized level authorized in the 2022 Gas Rate Case at Docket No. R-2021-3030218 and (2) over-recovery of reconciliation amounts from years prior to Fiscal 2022 (projected through Fiscal 2025). Please see the detailed calculations of this net over-recovery at UGI Gas Exhibit VKR-2.

The over-recovered expenditures of $1.221 million (line 9) will be credited to customers over a two-year amortization period through Fiscal Year 2027, at an amount of $0.610 million per year (line 11). This two-year amortization period is consistent with the period approved in the settlement of the prior rate case at Docket No. R-2021-3030218. This amount is compared to the budget amount of $3.029 million of expense per year, resulting in a budget adjustment of $3.639 million (line 13).

Q. What is the nature of the third Environmental Remediation expense adjustment shown on Schedule D-8, lines 14 – 16?

A. The third environmental adjustment is related to insurance settlement payments received by UGI Gas.

Q. Please further explain the insurance settlement payments.

A. Between June 2022 and December 2023, UGI reached settlement agreements with several of its insurance companies. Within these agreements, the insurance companies and UGI mutually agreed to release each other from certain claims, including claims related to certain MGP sites. In exchange for these agreements, UGI received settlement payments from these insurance companies.

Q. How were the settlement payments from these insurance companies treated within the Company's books and records?

A. The Company completed a calculation to estimate the portion of the settlement payments related to MGP costs which had been recovered from ratepayers in the past or would be recovered from ratepayers in the future. This portion of the settlement payments was recorded as a regulatory liability. The remaining portion of the settlement payments which was not related to costs recovered from ratepayers was recorded directly to income in the Company's financial statements.

Q. How were the settlement payments from these insurance companies treated within this rate proceeding?

A. For the portion of these settlement payments that was recorded as a regulatory liability ($27.378 million), the Company has included a budget adjustment at Schedule D-8, lines 14-16 to amortize these costs over 10 years. This amortization adjustment reduces the Company's overall revenue claim in this proceeding.

Q. Why did the Company select a 10-year amortization period?

A. As discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 9), the Company anticipates continuing to perform environmental remediation activities through at least 2035, which is the end of the term of the COA between PA DEP and the Company. This 10-year amortization period was selected because it coincides with this period.

Q. What ratemaking amount is used to determine the future years' Environmental Remediation costs subject to reconciliation in the next rate case?

A. That amount is the annual amount derived from the first adjustment on Schedule D-8, or $5.429 million, which is the normalized amount indicative of UGI Gas's experience over the past three years. Any future years' variance of actual annual expenditures from that figure will be credited to customers (in the case of an overcollection) or recovered from customers (in the case of an under collection) in the Company's next base rate case.

2. Uncollectible Accounts Expense

Q. Please explain the two adjustments shown on Schedule D-11 for Uncollectible Accounts Expense.

A. The first adjustment, $0.369 million (line 8, column 5), adjusts budgeted uncollectible accounts expense to reflect a three-year average rate of uncollectible accounts expense to tariff revenue for Fiscal Years 2022, 2023, and 2024. The baseline uncollectible accounts expense amount for Fiscal Year 2022 used in the calculation of the three-year average rate includes $4.008 million recorded as a regulatory asset (as further discussed under the second adjustment in Schedule D-11 below).

The amount of uncollectible expense in the budget is adjusted utilizing the three-year average uncollectible rate of 1.746 percent (line 4, column 5), The 1.746 percent is applied to the *pro forma* revenues at present rates (line 6, column 3) to calculate the *pro forma* uncollectible accounts expense of $19.775 million (line 7, column 4). This results in an increase in the level of uncollectible accounts expense for the FPFTY from the budgeted amount of $19.406 million (line 5). The 1.746 percent uncollectible rate is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule D-35.

The second adjustment on Schedule D-11 represents the amortization of the regulatory asset balance of $4.008 million for COVID-19 Pandemic Costs over a 10-year amortization period (in accordance with Ordering Paragraph 29 in the Commission's Order entered October 8, 2020 at Docket No. R-2019-3015162). According to Ordering Paragraph 30, COVID-19 Pandemic Costs include "annual uncollectible accounts expense in excess of $12.81 million beginning with the fiscal year period ending September 30, 2020 and continuing for annual periods thereafter until the effective date of the Company's next base rate filing . . . ." The same Ordering Paragraph indicates that such COVID-19 Pandemic Costs shall be eligible for recovery for ratemaking purposes.

For the Fiscal Year ended September 30, 2022, UGI Gas had uncollectible costs of $16.818 million, which resulted in an excess of uncollectible expense incurred over the established threshold of $12.810 million per year of $4.008 million, which was established as a regulatory asset and is being amortized over a 10-year period effective at the beginning of the FPFTY. This results in an increase in the level of uncollectible accounts expense for the FPFTY of $0.401 million, as shown on line 11.

Q. Why are COVID-19 Pandemic Costs incurred in Fiscal 2022 eligible for recovery?

A. Pursuant to the settlement on the UGI Gas 2022 Base Rate Case at Docket R-2021-3030218, the parties agreed to the following regarding COVID-19 Pandemic Costs incurred in Fiscal 2022.

> In accordance with this Settlement and the Commission's October 8, 2020 Final Order at Docket No. R-2019-3015162, the Company shall be permitted to amortize, over the 10-year period beginning with the effective date of rates established in the Company's next base rate proceeding for purposes of accounting and future ratemaking, the regulatory asset balance that accrues for uncollectibles beginning October 1, 2021, and ending September 30, 2022.

Q. What is the total increase (above the budgeted amount) for uncollectible accounts?

A. The total increase (above the budgeted amount) in the uncollectible accounts expense for the FPFTY is $0.770 million, as shown on line 12.

3. Benefits Expense Adjustment

Q. Please describe the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 reflects an adjustment from budgeted pension expense to reflect cash to be contributed to the plan in the FPFTY. The Company's budget reflects pension expense based on GAAP requirements to reflect service and non-service costs based on assumptions. However, consistent with prior ratemaking practices, the

Company claims pension costs within its rates on a cash basis. The adjustment is calculated as the total cash contributions (as provided by the Company's actuary in the most recent actuarial report), reduced to reflect only the portion attributable to UGI Gas, and then further reduced to reflect the portion of pension that is capitalizable. This cash pension expense of $5.066 million (line 5) is compared to the budgeted pension expense of $1.547 million (line 1), also calculated for UGI Gas only and net of the capitalizable portion, resulting in an adjustment of $3.519 million (line 6).

4. Injuries and Damages Adjustment

Q. Please discuss the adjustment for Injuries and Damages shown on Schedule D-15.

A. The amount of expense incurred for injuries and damages in any one year can vary based on the quantity and severity of the claims. The Company bases its claim for injuries and damages on a normalized amount. This is accomplished by making an adjustment on this schedule for the difference between the normalized amount and the budgeted amount. The three-year average of injuries and damages expenses of $2.218 million is calculated on lines 1 – 4 of Schedule D-15. The budgeted amount for injuries and damages, $1.586 million, is shown on line 5. The difference between these amounts, $0.631 million, was used to adjust budgeted injuries and damages expense, as shown on line 6, to reflect the normalized expense.

5. Customer Accounts Expense Adjustment

Q. Please discuss the adjustment for Customer Accounts Expense shown on Schedule D-15.

A. This adjustment includes a component to recover interest on customer deposits. The Company is required to pay interest on Customer Deposits that it holds in accordance with its tariff requirements. As this is a typical business expense, the Company has added this amount to its expense claim that is otherwise not reflected in the operations budget. It is calculated by using the average level of customer deposits anticipated for the FPFTY (*i.e.*, $22.616 million) times the required interest rate (7.0 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and as required under the Company's tariff. The total interest on customers deposits amount of $1.583 million is shown on line 7.

VI. CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY COSTS

Q. What is the Company's policy for capital treatment of certain information technology ("IT") costs?

A. Since 2016, UGI (including UGI Gas and UGI Electric) has received authorization to capitalize certain IT costs associated with software implementation projects within various base rate proceedings. These IT costs consist of internal labor, external consulting expenses, and other expenses related to the preparation of the vendor and system integrator requests for proposals. IT costs also include current-state assessments, reengineering business processes to adapt to the new system, data conversion, cleansing and migration (including field verification and digitization of asset attributes required for accurate data and facility capture), and implementation training costs. Additionally, the Company capitalizes the above-mentioned cost items for cloud computing software implementation projects. Further, beginning in 2019, the Company began capitalizing Hypercare costs associated with large software implementation projects. Hypercare is a term for post-implementation support following the deployment of an IT project to ensure that the newly implemented system operates as planned.

Q. Is the Company planning to continue with similar methods of IT costs capitalization in this proceeding?

A. Yes. The Company continues to capitalize such costs in line with the authorizations received previously, and all such costs which are claimed in the current case are included within the Company's budgeted capital as laid out in Exhibit A (Future) and Exhibit A (Fully Projected).

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VKR-1

Vivian K. Ressler

Director – Utility Financial Planning & Analysis

Work Experience

UGI Utilities, Inc. – Denver, PA

Oct. 2024 – Current	Director – Utility Financial Planning & Analysis
Jan. 2023 – Sept. 2024	Sr. Manager - Finance
March 2022 – Jan. 2023	Assistant Controller
Dec. 2021 – March 2022	Sr. Manager – Plant & Regulatory Accounting
Feb. 2020 – Dec. 2021	Sr. Manager – SOX, Plant Accounting & Accounts Payable
June 2018 – Feb. 2020	Manager – Technical Accounting & Controls

The Bon-Ton Stores, Inc. – York, PA

May 2014 – May 2018	Departmental Vice President – Corporate Accounting

Trout, Ebersole & Groff, LLP – Lancaster, PA

May 2012 – May 2014	Supervisor – Attest Services

BI-LO, LLC – Greenville, SC

Nov. 2007 – May 2012	Sr. Manager – Corporate Accounting & Tax

Deloitte & Touche, LLP – Greenville, SC

Sept. 1998 – Oct. 2007	Staff Accountant through Sr. Manager – Audit Services

Previous Testimony before the Pennsylvania Public Utility Commission

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Electric Base Rate Case	Docket No. R-2021-3023618
UGI Gas Base Rate Case	Docket No. R-2021-3030218
UGI Electric Base Rate Case	Docket No. R-2022-3037368

Education & Professional Certification

B. S. in Accounting – Bob Jones University, Greenville, SC

Certified Public Accountant – Commonwealth of Pennsylvania

UGI GAS

EXHIBIT VKR-2

UGI Utilities, Inc. - Gas Division
Reconciliation of Environmental Recovery
$ Amounts in '000s

Under / (Over) Recoveries Approved in Prior Rate Case:

Line #	Year(s) to which Under / (Over) Recovery Relates	Docket No. of Rate Case in which Amortization was Mostly Recently Approved	Annual Amortization in Current Rates	Under Recovered Balance at 9/30/2021	FY22	FY23	FY24	FY25	(Over) Recovered Balance at 9/30/2025	
1	Prior to FY20	R-2021-3030218	$ 1,865	$ 5,898	$ (1,865)	$ (1,865)	$ (1,865)	$ (1,865)	$ (1,562)	
2	FY20 & FY21	R-2021-3030218	1,164	2,327	-	(1,067)	(1,163)	(1,164)	(1,066)	
3	Additional Over-Recovery	(1)							(432)	
4	Total		$ 3,028	$ 8,225	$ (1,865)	$ (2,931)	$ (3,028)	$ (3,028)	$ (3,060)	Schedule D-8, Line 7
									(2)	

Under / (Over) Recoveries since Prior Rate Case:

Line #	Year(s) to which Under / (Over) Recovery Relates	Actual Spend in Fiscal Year	Normalized Environmental Costs Included in Rates	Under / (Over) Recovery	Under / (Over) Recovered Balance at 9/30/2025	
5	FY22	$ 3,244	$ 4,188	$ (944)	$ (944)	
6	FY23	5,441	5,089	352	352	
7	FY24	7,602	5,171	2,431	2,431	
8	Total	$ 16,288	$ 14,449	$ 1,839	$ 1,839	Schedule D-8, Line 8
					(2)	

(1) Amount identified as an over collection of environmental costs prior of FY18 since the prior base rate proceeding as a result of internal reconciliation.
(2) Amounts are included within Environmental Adjustment #2 at Schedule D-8 of Exhibit A, Fully Projected

UGI GAS STATEMENT NO. 4

JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 4

Direct Testimony of
John F. Wiedmayer, C.D.P.

Topics Addressed: **Depreciation and Net Salvage**

Date: January 27, 2025

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2024-3052716

I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm and in what capacity?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Project Manager, Depreciation and Valuation Studies.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since I graduated from college in June 1986.

Q. What is your educational background?

A. I have an AB degree in Engineering from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals ("SDP"). In 2005, I served as President of the SDP and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The SDP has established national standards for depreciation professionals. The SDP administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. I have over 38 years of depreciation experience, which includes expert testimony in numerous cases before 14 regulatory commissions, including the Pennsylvania Public Utility Commission ("PUC" or "Commission").

In June 1986, I was employed by Gannett Fleming as a Depreciation Engineer. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to Project Manager, Depreciation Studies and in January 2022 I was promoted to my present position as Senior Project Manager, Valuation and Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration, and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming, I have assisted in the preparation of numerous depreciation studies for utility companies across various industries. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Commonwealth Telephone Company, Telus, United Telephone Company of New Jersey, and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, UGI Utilities, Inc. - Electric Division ("UGI Electric"), Penelec, Metropolitan Edison, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, TXU, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: BGE, PECO, UGI Utilities, Inc. – Gas Division, North Penn Gas, PFG Gas, UGI Central Penn Gas, Inc., Equitable Gas, Centra Gas Alberta, Questar Gas, Orange and Rockland, Con Edison, Dominion East Ohio, Connecticut Natural Gas, Southern Connecticut Gas, AmerenUE, AmerenCILCO, AmerenCIPS, and AmerenIP.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities, the New York Public Service Commission, the Connecticut Public Utilities Regulatory Authority, and the PUC.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation

Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." In 2000, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," "Analyzing the Life of Real-World Utility Property – Actuarial Analysis," "Theoretical Reserve Imbalances and True-Up," and "Data Requirements for a Depreciation Study."

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the Pennsylvania gas plant of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I was retained by the Company as a depreciation consultant. UGI Gas retained me to determine the book depreciation reserve as of September 30, 2026, to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI Gas's depreciated original cost of gas plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual depreciation expense to be included in the ratemaking cost of service as of September 30, 2026.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following items in UGI Gas Exhibit I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
I-A-8	Trended Original Cost Methodology
I-A-9	Spot Trended Original Cost
I-A-10	Undepreciated Original Cost
I-A-11	Cumulative Trended Depreciated Original Cost
I-A-17	Net Salvage

Q. Have you previously prepared comparable studies for UGI Gas?

A. Yes. I provided testimony on depreciation matters for the Company in the prior two UGI Penn Natural Gas ("PNG") base rate cases at Docket No. R-2016-2580030 and Docket No. R-2008-2079660, the prior two UGI Central Penn Gas ("CPG") base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675 and the four most recent base rate case for UGI Utilities, Inc. – Gas Division at Docket No. R-2015-2518438, Docket No. R-2018-3006814, Docket No. R-2019-3015162 and Docket No. R-2021-3030218. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's base rate case filed in 1995 at Docket No. R-00953297.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am attaching and sponsoring the following exhibits: UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Historic). UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ("FPFTY") ending September 30, 2026, for UGI Gas. UGI Gas Exhibit C (Future) presents similar summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ("FTY") ending September 30, 2025. UGI Gas Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ("HTY") ended September 30, 2024. Each of the three exhibits is organized in a similar manner and contains information and schedules supporting the amounts applicable to each test year period. UGI Gas Exhibit C (Future) contains additional information including the supporting life tables and life table charts related to the service life estimates.

Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2026?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study reports, UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected).

A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report prepared by me and submitted in 2019. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Estimation of Survivor Curves, presents detailed discussions of: (1) survivor curves; and (2) methods of life analysis, including an example of the retirement rate method. Part III, Service Life Considerations, presents the relevant factors considered for estimating service lives. Part IV, Calculation of Annual and Accrued Depreciation, sets forth a description of: (1) the group procedures used for calculating annual and accrued depreciation; and (2) an explanation of the manner in which net salvage was incorporated in the calculations. Part V, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2025. Part VI, Service Life Statistics, presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2025. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains the net salvage amortization of experienced and estimated net salvage for the years 2021 through 2025.

UGI Gas Exhibit C (Fully Projected) includes: a description of the scope, basis, and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2026. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Gas Exhibit C (Future) also support the service life estimates used in UGI Gas Exhibit C (Fully Projected) inasmuch as the estimates are the same for all three test years, i.e., HTY, FTY, and FPFTY. The service life estimates set forth in UGI Gas Exhibit C (Historic) are the same estimates as those approved in the Company's Annual Depreciation Report ("ADR") submitted to the PUC in March 2024. The pro forma depreciation expense for UGI Gas at the end of the HTY, September 30, 2024, is the sum of the three former rate districts, UGI South, UGI North, and UGI Central.

The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully Projected). Table 1, pages II-3 through II-5 of UGI Gas Exhibit C (Fully

Projected), presents the estimated survivor curve, the original cost and depreciation reserve as of September 30, 2026, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-6 through II-7 of UGI Gas Exhibit C (Fully Projected), presents the bring-forward to September 30, 2026, of the depreciation reserve as of September 30, 2025. Table 3, pages II-8 through II-10 of UGI Gas Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-11 through II-12 of UGI Gas Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2022 through 2026. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2021 through September 30, 2026. The summary tables and detailed depreciation calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September 30, 2026, are organized and presented in the same manner as those presented in UGI Gas Exhibit C (Future) as of September 30, 2025.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Gas Exhibit C (Historic) is organized similarly to UGI Gas Exhibit C (Fully Projected). UGI Gas Exhibit C (Historic) includes: a description of the scope, basis, and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2024. The service life estimates used in the HTY period were based on the survivor curve estimates set forth in the ADR submitted to the PUC in March 2024. The same survivor curve estimates were used in each of the three respective test year periods and were based on a service life study submitted to the PUC in 2023 using plant accounting data through fiscal year-end 2022. The summary tables and detailed depreciation calculations as of September 30, 2024, are organized and presented in the same manner as those as of September 30, 2026, with two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Gas Exhibit C (Historic).

IV. THE DEPRECIATION STUDY - OVERVIEW

Q. Please describe what you mean by the term "depreciation."

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts prescribed for Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, requirements of public authorities, and the exhaustion of natural resources.

In the study that I performed, which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner. For clarity of presentation, the detailed depreciation calculations are presented by account, vintage year and former rate district, the sum of which totals to the consolidated PA-jurisdictional UGI Gas company which excludes a small portion of the UGI gas system located in Maryland. The depreciation summary tables present the results on a total PA-jurisdictional UGI Gas basis.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation that were used in the Company's March 2024 ADR?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used by the Company for over forty years. The depreciation methods and procedures are described further in Part II of UGI Gas Exhibit C (Future).

For General Plant Accounts 391, 393, 394, 395, 397, and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of gas plant to be included in rate base in this proceeding?

A. As of September 30, 2026, the original cost of gas plant in service is $6,218,576,168 as shown in column 4 of Table 1 on pages II-3 through II-5 of UGI Gas Exhibit C (Fully Projected). This amount includes $5,952,407,430 of Gas Plant and $266,168,738 of Other Utility Plant allocated to UGI Gas. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used between UGI Gas and UGI Electric. The costs related to Common Plant and IS are allocated to UGI Gas at 89.89 percent and 84.82 percent, respectively. Also, the full cost of the buildings at the Empire Service Center ("Empire") in Wilkes Barre, PA were included in Gas Division. However, personnel of UGI Electric share portions of the buildings at that location and therefore a portion of the cost related to Empire was deducted from UGI Gas and allocated to UGI Electric for this proceeding.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Gas's accrued depreciation for ratemaking purposes as of September 30, 2026?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2026, to be $1,618,835,540.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over forty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve set forth in the Company's financial statements and approved annually in connection with the Company's submission of its annual depreciation report each March to the Commission.

Q. How did you determine UGI Gas's allocated book depreciation reserve as of September 30, 2025?

A. The book depreciation reserve attributable to UGI Gas as of September 30, 2025, is set forth in column 5 of Table 1 of UGI Gas Exhibit C (Future). Table 2 of UGI Gas Exhibit C (Future) is an annual bring-forward of the book depreciation reserve as of September 30, 2024, using estimated accruals, retirements, salvage, and cost of removal for the twelve months from October 2024 through September 2025. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2024, the estimated reserve activity, and the ending reserve balance as of September 30, 2025. The estimated reserve activity consists of depreciation accruals (column 3), amortization of net salvage (column 4), projected retirements (column 5), projected salvage (column 6), and projected cost of removal (column 7). Table 3 of UGI Gas Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account, which is carried forward to column 3 of Table 2. The book reserve as of September 30, 2024, by plant account, shown in column 2 of Table 2, was obtained from UGI Gas's books and records and are the same amounts set forth in Table 1 of Exhibit C (Historic).

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2025.

A. The depreciation accruals for the twelve months ended September 30, 2025, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2024, to the projected average 2025 plant balance. The average balance for the twelve months ended September 30, 2025, is computed in columns 2 through 7 of Table 3 and is based on the projected additions, retirements, and transfers in columns 3 through 5.

Q. With reference to Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced net salvage during the preceding five-year period, October 1, 2019 through September 30, 2024.

Q. Please explain the manner in which you projected the retirements, salvage, and removal costs that are shown in columns 5, 6, and 7 of Table 2.

A. Retirements were projected by plant account by applying the average retirement ratio, expressed as a percent of additions, for the five fiscal years 2020 through 2024, to FTY and FPFTY additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the FTY for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal ratios, expressed as a percent of retirement amounts, for the five years 2020 through 2024, to the projected retirement amounts.

Q. Was the book reserve as of September 30, 2026, estimated using the same methodology?

A. Yes, it was essentially the same methodology with one minor exception. The book depreciation accruals calculated for fiscal year 2026 were based on applying the depreciation rate to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2026.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Gas's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $167,121,205 and consists of $159,032,451 of annual accruals to recover original cost and $8,088,754 of net salvage amortization. These amounts are set forth in column 8 of Table 1 in UGI Gas Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $167,121,205?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, survivor curves are estimated for each plant account or subaccount. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study consisted of compiling historical data from records related to UGI Gas's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from engineering management and operating personnel concerning UGI Gas's practices and plans as they relate to plant operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of UGI Gas's gas plant?

A. The data consisted of the entries made by UGI Gas to record gas plant transactions during the period 1951 through 2022. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate method when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type survivor curve and were not used.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used in these interpretations. The results of the retirement rate analyses are presented in Part VI of UGI Gas Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you use it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves ("Iowa curves"). The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania, as well as the remaining 49 states, and have been for many years.

Iowa curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system, and the relative height of the mode. For example, the Iowa 35-R2 curve indicates an average service life of thirty-five years; and a Right-skewed, or R, type curve (the mode or highest frequency of retirements occurs after average life for right modal curves). It also provides a relatively low height, 2, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the Company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the Commission every five years, at a minimum. UGI Gas's most recent service life study report was performed in 2023 using plant accounting data through September 30, 2022. Facilities visited during field trips generally include representative city gate stations, district regulating stations, service centers, office buildings, training centers, etc. The specific dates and locations visited during recent field trips are listed in Exhibit C (Future) in Part III. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe the second phase of the process that you used in order to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1982 and remaining lives consistent with the equal life group procedure for plant installed in 1982 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth on Table 1 of UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

Q. Please briefly describe the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please briefly describe the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1982.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please briefly describe the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1982 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please briefly describe the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 393, 394, 395, 397, and 398 include a very large number of units but represent a very small percent of depreciable gas plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant accounting expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired per books when the age of the vintage reaches the amortization period.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 376.1, Mains – Primarily Steel, to illustrate the manner in which the study was conducted. Account 376.1 represents 13 percent of the total depreciable gas plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2022. These data have been coded in the course of UGI Gas's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes primarily cathodically-protected, steel mains, although some bare steel mains are still in service. As detailed in UGI Gas Exhibit C (Future), the Iowa 75-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The 75-R2.5 is a reasonably good fit of the company's historical plant accounting data, consistent with engineering outlook and within the typical range of service lives used by other gas companies for steel mains. The original life table for the 1951-2022 experience band is set forth on pages VI-22 through VI-27.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service as of September 30, 2025, is presented by vintage in Part VII on pages VII-37 through VII-45 of UGI Gas Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations as of September 30, 2026, are presented in Part III of Exhibit C (Fully Projected). The tabular presentations of the detailed depreciation calculations in Part VII of Exhibit C (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully Projected). The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1981 and prior vintages.

The accrued depreciation for vintages subsequent to 1981 was calculated by the equal life group procedure using the Iowa 75-R2.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 75-R2.5 survivor curve. The accrued depreciation was derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 75-R2.5 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page VII-45 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 4 in order to calculate the annual depreciation accrual rate in column 7. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 376.1 typical of that followed for most of the plant investment?

A. Yes, it is, inasmuch as the straight line method, the average service life, and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an amortization period of 20 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the service life estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2025, is presented by vintage in Part VII on pages VII-145 and VII-146 of UGI Gas Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page VII-146 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-5 of UGI Gas Exhibit C (Future). A similar process was performed for UGI Gas Exhibit C (Fully Projected) and UGI Gas Exhibit C (Historic). That is, the calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service as of September 30, 2026, is presented by vintage on pages III-143 and III-144 of UGI Gas Exhibit C (Fully Projected) and summa-rized in Table 1 on page II-4.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span approach was applied to major structures in Account 390. The life span approach was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

IX. THE NET SALVAGE AMORTIZATION CLAIM

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in CPG's (formerly PPL Gas Utilities Corporation ("PPL Gas")) 2006 rate filing (Docket No. R-00061398) and have been utilized by UGI Gas in their rate cases ever since. This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the Company's ADR submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI Gas's annual depreciation expense consists, in part, of $8,088,754 of net salvage amortization. How did you determine that amount?

A. The $8,088,754 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2021 through September 30, 2026. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI Gas, cost of removal exceeds gross salvage resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Part VIII of UGI Gas Exhibit C (Future) and Part IV of UGI Gas Exhibit C (Fully Projected).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items I-A-5, I-A-6, and I-A-7. In general, these responses are self-explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the HTY, FTY, and FPFTY, respectively. The response to I-A-6 presents the survivor curves used in the most recent general rate proceeding and the annual accrual rates that resulted from the use of these curves. The response to I-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected) in the section titled "Cumulative Depreciated Original Cost."

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS STATEMENT NO. 5

VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 5

Direct Testimony of
Vicky A. Schappell

Topics Addressed: **Capital Planning**

Dated: January 27, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed as a Senior Manager, Capital Planning by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit VAS-1 to my testimony.

Q. What are your responsibilities as Senior Manager?

A. As Senior Manager, I supervise a team of Analysts responsible for the preparation of the annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining budget inputs from various departments including Engineering, Operations, Corrosion, Marketing, Information Technology ("IT"), and the Building and Grounds Departments. I collaborate with the Vice President of Operations, the Vice President of Global Engineering, the Director of Engineering Design, the Director Customer Development, the Director of Pipeline System Planning and Optimization, the Director Financial Planning and Analysis and Senior Engineering Managers to monitor annual capital budget performance and develop strategies to limit variances in capital installations and spending. I also work closely with the President of UGI in developing the overall capital spend strategy. In this role, I have also prepared testimony, supporting exhibits and schedules, and sponsored responses to discovery requests for past base rate cases. Also, I am responsible for preparing UGI Gas's Annual Asset Optimization Plan. Additionally, I had an integral role in developing an expanded capital spending monitoring process necessary for managing the Company's accelerated capital investments programs.

Q. Have you previously presented testimony in proceedings before a regulatory agency?

A. Yes. UGI Gas Exhibit VAS-1 contains a list of those proceedings.

Q. What is the purpose of your testimony?

A. My testimony will address the capital planning process used by UGI Gas which supports the plant in service expenditures included in the proposed rates in this proceeding, specifically as related to plant additions for the future test year ending September 30, 2025 ("FTY") and the fully projected future test year ending September 30, 2026 ("FPFTY" or "FY2026").

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to UGI Gas Exhibit VAS-1, I am sponsoring UGI Gas Exhibit VAS-2. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. CAPITAL PLANNING

Q. What is the total plant in service budget for UGI Gas for the FPFTY that is reflected in the proposed rates?

A. The total budgeted plant additions for UGI Gas for the FPFTY is $462,899,000.

Q. What are the specific project categories included in the capital budget for UGI Gas?

A. UGI Gas has four main categories that make up its capital budgets: (1) replacement and betterment infrastructure; (2) new business; (3) IT; and (4) other capital spending. I will describe each of these categories and the projects associated with them, as well as the total dollars attributable to each category below.

Q. What process does UGI Gas use to develop its capital budget?

A. UGI Gas's capital budget starts by identifying the four critical areas where the Company must make capital investments in order to maintain safe and reliable service to customers. For each of these budget areas, the Company then identifies all of the projects or categories of project that are planned to occur in each fiscal year of a two-year forecast. Once those projects are determined, the Company identifies the FERC accounting treatment for each project. In this case, the Company presents them as part of the budgeted plant additions in Exhibit A, Schedule C-2. The process used to develop Exhibit A is further described in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2).

Q. How does Schedule C-2 show plant additions?

A. Schedule C-2 is an accounting presentation based on FERC accounts. For purposes of developing Schedule C-2, budgeted dollars in each budget category are broken out by the

FERC account numbers that drive the accounting for depreciation. Schedule C-2 is split between Distribution Plant and General and Common plant. The General and Common Plant includes only the distribution portion of the plant additions for UGI Gas.

Q. Have you prepared an exhibit that shows UGI Gas's plant additions broken down by budget project categories?

A. Yes, I have. UGI Gas Exhibit VAS-2 reflects the Company's plant additions broken out by the different project categories for the five-year period from fiscal year 2022 through fiscal year 2026. The exhibit splits the four budget project categories between Distribution Plant and General and Common plant, consistent with the categories on Schedule C-2. In addition, UGI Gas Exhibit VAS-2 shows a historical comparison of the total budgeted plant placed in service versus actual plant placed in service additions for the three-year period from fiscal year 2022 through fiscal year 2024. I will describe how the Company's performance history supports the reasonableness of the Company's FTY and FPFTY plant additions in greater detail later in my testimony.

Q. Please comment on the presentations shown in UGI Gas Exhibit VAS-2 and Schedule C-2.

A. While the forecasted total plant in service figures match for the FTY and the FPFTY, there is a difference in the presentation of how UGI Gas Exhibit VAS-2 and Schedule C-2 present plant additions, and it is important to understand how these budget presentations align. Specifically, UGI Gas Exhibit VAS-2 shows how the Company's four individual budget categories constitute the Company's total Plant Additions and how they map into the Distribution and General and Common Plant on Schedule C-2. Exhibit VAS-2 shows that three of the four budget categories fall into both of the plant categories (i.e., Distribution Plant and General & Common Plant) when describing the budget by FERC accounts. IT projects are the only budget category where projects fall exclusively into one FERC plant account – General and Common plant – when recorded for accounting purposes.

Q. Why is it important to understand the relationship between the Company's budgeting process and the reflection of the budget in Schedule C-2?

A. When the Company plans for future plant additions, the Company utilizes a project based build-up and does not directly budget using the FERC accounts, as work streams do not directly correlate to the format shown in Schedule C-2. When the Company budgets and then executes on its budget, it first looks at the total for the budget category, and then examines its overall budgeted projects on a total additions basis, because its operations and work streams are divided in the same manner to achieve core utility objectives. Ultimately, the Company's operations manage to the total overall budget. As a result of this process, it is more reasonable to review the Distribution and General and Common plant levels together when considering how the Company performed to its budget, rather than the accounting distinction set forth in Schedule C-2. Thus, to properly compare historical budgeted plant additions to actuals for ratemaking purposes, the Distribution and General and Common plant additions should be reviewed in total.

Q. Turning to the capital budget categories, what are replacement and betterment projects?

A. Replacement and betterment ("R&B") projects improve or replace or repair existing infrastructure and include, but are not limited to, leak remediation, pipe relocations, material upgrades, service renewals, reliability improvements, and metering and regulation upgrades.

Q. Please describe the prioritization process that is used to evaluate R&B projects.

A. Projects are prioritized for inclusion in the budget according to the condition of, and risks associated with, existing assets, including those factors affecting safety and reliability. In determining the condition of an existing asset, the Company considers various criteria including, but not limited to the replacement of cast iron and bare steel pipe, which are more susceptible to failure from corrosion, cracks, and leakage (as compared to other pipe materials). UGI Gas has also committed to replacing identified priority plastic pipe, in addition to cast iron and bare steel pipe as defined in its Third Long Term Infrastructure Improvement Plan ("LTIIP") as discussed below. Risk evaluations for mains are based on numerous factors, including condition, age, coating, type of ground cover, geographical proximity to structures and prior leak and/or break history. UGI Gas reviews these factors annually to identify the highest risk pipe segments and prioritize them for replacement.[1] Specifically, commercial risk evaluation software is used in concert with a team of Subject

[1] When replacing mains, the Company also replaces associated distribution equipment, including service lines, as well as installing or replacing safety and monitoring devices (excess flow valves), meters, risers, and meter bars. Additionally, indoor meters are relocated to an outside location, except in certain circumstances. Similarly, regulator stations and service regulators are reviewed and prioritized for replacement based on nearby main replacement projects or required upgrades due to the updated equipment installed as part of the main replacement program.

Matter Experts to evaluate, prioritize, and bundle replacement projects. Furthermore, UGI Gas's Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP") provide a detailed listing and weighting of factors considered in the risk-based evaluation, which may cause specific projects to be reprioritized for replacement on a more accelerated basis. This hybrid approach targets the highest risk mains first, while also balancing the need to maximize the efficient deployment of capital and resources.

UGI Gas's prioritization of projects for its capital budgets also is consistent with its LTIIP, which is described in more detail in the direct testimony of UGI Gas witness, Christopher R. Brown (UGI Gas Statement No. 9). LTIIP replacement investments are identified and prioritized on a risk basis in accordance with UGI Gas's DIMP.

Q. How does UGI Gas determine which R&B projects are included in the capital budget for a given year?

A. UGI Gas's LTIIP guides the formulation of the overall R&B capital budget. Within the various categories of the LTIIP, R&B projects are selected and prioritized according to the risk-based evaluation process that I described above. The total anticipated budgeted plant additions associated with R&B projects in the FPFTY is $327,765,000 of which $327,669,000 is included in Distribution plant additions and $96,000 is included in General and Common plant Additions.

Q. What are new business projects?

A. New business projects provide new or upgraded gas service to customers and may involve the installation of new gas mains and services to support conversions to natural gas service (from other heating sources).

Q. Please describe how the new business infrastructure projects are selected for inclusion in the capital budget.

A. The new business portion of the capital budget is developed according to forecasts of new business opportunities, projections of customer conversions, and plans for new construction and development projects. The total anticipated budgeted plant additions associated with new business projects in the FPFTY is $68,465,000; these additions are included in Distribution plant additions.

Q. What are IT projects?

A. IT projects enhance the Company's IT systems in a number of ways. These projects involve hardware and software applications which improve the Company's processes and methods across a wide range of operational concerns or needs, such as capital project management, cybersecurity, customer communications, billing as well as other areas. Further, these projects facilitate the Company's ability to enter, store, retrieve, and send data and information related to such projects. Specific large IT projects reflected in the FPFTY include Field Services Management ("FSM") and Extended Asset Accounting ("EAA") as further described below. The total anticipated budgeted plant additions associated with IT projects in the FPFTY is $36,394,000 and these projects are included in General and Common plant additions.

Q. Please describe the prioritization process used to evaluate IT projects.

A. IT projects are prioritized for inclusion in the budget based on identified business needs. UGI relies on an IT Prioritization Committee to develop a prioritized budget based on overall business impact, availability of system support, and resource availability. Examples of IT projects include the Pipeline Risk Management – TIMP project that went into service in September 2024. This project focused on standardizing a tool to maintain compliance and mitigate asset risk.

Q. What are Other capital projects?

A. Other capital projects include building-related projects, corrosion control projects, capital tool purchases, and fleet purchases. Building-related projects consist of building and land purchases, building improvements/renovations, and the purchase of furniture. Corrosion control projects include upgrades and replacements of cathodic protection systems for mains. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include tapping and stopping equipment, safety tools, and leak detection equipment. Fleet purchases are needed to maintain a reliable mode of transportation for field employees along with certain specialty equipment required to perform daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service body trucks, compressor crew trucks, vacuum trucks, aerial lift trucks, dump trucks, backhoes, excavators, forklifts, and equipment trailers for backhoes and excavators. The total anticipated budgeted plant additions associated with other projects in the FPFTY is $30,275,000 of which $9,750,000 is included in Distribution plant additions and $20,525,000 is included in General and Common plant additions (UGI Gas Exhibit VAS-2).

Q. Please describe the prioritization process used to evaluate Other capital projects.

A. The prioritization process for Other capital projects is specific to the need being addressed. Building-related projects are prioritized for inclusion in the budget based on safety, security, regulatory, or financial and strategic needs. Regulatory driven projects may originate from compliance requirements or certain audit observations. Physical security audits may prompt the installation of fencing, gates and access controls. Corrosion control projects involving coated steel main replacements are prioritized for inclusion in the budget according to requirements set forth in the Federal Gas Safety Regulations (49 C.F.R. Part 192).[2] Corrosion control projects also may depend on unrepairable leakages or emerging main issues. Capital tool projects are prioritized for inclusion in the budget according to the useful life of the existing assets. Fleet purchases are prioritized for inclusion in the budget based on age, condition, maintenance costs, and mileage of the existing asset.

[2] Transmission lines may be replaced due to corrosion that affects wall thickness pursuant to 49 C.F.R. § 192.485. Additionally, portions of transmission lines (with localized corrosion pitting) may be replaced pursuant to 49 C.F.R. § 192.485. Similarly, distribution lines with corrosion (or portions thereof with localized pitting corrosion) may be replaced pursuant to 49 C.F.R. § 192.487. Lines also may need to be replaced if they lack cathodic protection systems, as detailed in 49 C.F.R. § 192.463.

Q. Please describe the FSM project.

A. The FPFTY includes costs related to the FSM project, which will enhance the efficiency of planning, scheduling, dispatching of field work via mobile field interface, integrating directly with UGI Gas's existing UNITE technologies. Scheduling and dispatching of short-interval work is currently done centrally, while long-interval work is managed by local operating districts. This existing process can result in inefficiencies with planning, scheduling, and resource utilization. UGI Gas will implement this FSM solution as the first step towards a large Enterprise Asset Management System ("EAM"), which will include (1) main replacement, distribution system reinforcement, and line extension projects; (2) service installations; (3) new and upgraded regulator stations; (4) inspections, maintenance, and other repairs; (5) paving and restoration; and (6) facility location and damage prevention. As a precursor to the broader EAM implementation, this FSM project will encompass the scheduling, dispatching and field completion of planned and unplanned work using SAP Service & Asset Manager ("SSAM") and SAP Field Service Management ("SAP FSM"). SSAM and SAP FSM will replace the legacy scheduling, dispatching, and mobility system Accruent MobileUp for existing types of field work. This includes short-interval work from the Company's existing Customer Resources and Billing solution ("SAP CR&B") as well as non-customer long and short-interval work from UGI's legacy work management system Distribution Operational Job Management ("DOJM"). The non-customer short interval work includes valve inspections and regulator station inspections. The non-customer long interval work includes main projects, scheduled leak repairs and installing new main and services. The legacy Accruent MobileUp mobility system has reached its end of life and FSM is the first step towards the EAM, which will replace and enhance the functionality from DOJM. SSAM is a mobile app running in the cloud that enables field technicians to access, capture and work with asset and operational data on their devices.

Q. Please describe the project timing of the FSM project.

A. The Company began to perform analysis and requirement planning in 2022 as part of its previous efforts under the UNITE initiatives. UGI Gas has spent approximately $1.7 million on the requirement efforts to date. The requirement phase of the project is currently expected to be completed mid-February 2025. The Company is also expecting to have the final pricing and Request for Proposal ("RFP") responses in March 2025. FSM approval by the UGI Corporation Board is anticipated to occur in May 2025 with a planned in-service date of July 2026.

Q. What costs are included in the FPFTY for the FSM?

A. The FSM project total costs to UGI is approximately $23 million. UGI Gas's portion of these costs is approximately $19.5 million. The total costs are included in the IT budget category. The costs are also categorized as General and Common Plant additions.

Q. Please describe the EAA project.

A. This project will deliver a consolidated SAP Enterprise Resource Planning ("ERP") solution as well as implementing an SAP certified add-on for asset accounting known as "Finance 4U EAA" tool to support Acquire-to-Retire ("A2R") business processes and delivering a capital planning business process through SAP Analytics Cloud ("SAC").

UGI currently leverages SAP ERP S/4 HANA and a hosted, interfaced instance of PowerPlan as its accounting and capital budgeting applications. The planned project will implement Finance 4U EAA system as the core, consolidated fixed asset solution and SAC for capital budgeting. EAA is an SAP Certified Integration, built on the HANA S/4 platform. It utilizes all the existing cost collectors built in the SAP ERP. The SAC Capital Budgeting solution is a modern cloud-based tool that leverages features that look, feel, and behave like excel. The overall user experience will also be streamlined across the ERP and SAC, allowing for system functionality to be triggered centrally from SAP.

EAA was approved in August 2024, an official kick off occurred in October 2024, and it has a planned in-service date of October 2025.

Q. Does EAA replace a current solution?

A. This application is being proposed to replace the existing PowerPlan product. This project will align the accounting solutions of UGI Gas and should be completed as a prerequisite to EAM, which will introduce a new way of integrating capital projects to fixed asset records with the intention to build a seamless hand off between the construction project and the fixed asset record. This requires that the base structure of the fixed asset system be in place and stable prior to any EAM implementation. Due to current system limitation, most business processes are manual. Retiring PowerPlan enables a more streamlined application.

PowerPlan currently relies on a series of complex interfaces; eliminating these interfaces reduces overall solution risk and complexity. PowerPlan is not a natively integrated system. To operate PowerPlan as a sub-system of SAP, UGI employs a collection of replicated objects through a secondary database that is updated in real time. PowerPlan uses a set of interfaces, running on a schedule or ad-hoc basis, to process the replicated data. Transactions for fixed assets and depreciation are created and applied to accounts defined within PowerPlan. These transactions are accumulated and posted back to SAP using a series of interfaces with a combination of PowerPlan and SAP processing techniques. While this process is effective, it is not in real time. It is generally reliable integration, but there are performance issues and failure points. It is not unusual for systems to experience minor out of balance issues.

Q. What costs are included in the FPFTY for the EAA?

A. The EAA project total cost to UGI is approximately $14 million. UGI Gas's portion of these costs is approximately $11.2 million. The total costs are included in the IT budget category. The costs are also categorized as General and Common Plant additions.

Q. Please discuss some of the key drivers which support the increase in UGI Gas's FPFTY plant additions as compared to the HTY.

A. The planned capital for FY2026 includes cost increases in R&B associated with complexity, location and size of the remaining cast iron and bare steel replacement projects as well as general resource cost increases. It also includes priority plastic pipe as Distribution System Improvement Charge-eligible property that will be replaced through the LTIIP on an accelerated basis to reduce associated leaks and overall risks on the Company's distribution system, as defined in the Company's Third LTIIP at Docket No. P-2024-3050769. The Company's total planned 2026 replacement miles will be 60-70 miles with such increase corresponding to an increase in the planned plant additions. The Company replaced approximately 51 miles of cast iron, bare steel and wrought iron main in FY2024.

Q. How can UGI Gas's actual in-service plant additions be compared to budgeted in service plant additions historically in order to demonstrate Company performance?

A. As shown in UGI Gas Exhibit VAS-2, over the past three years, the Company's total budgeted in service plant additions were $1,274,869,000, while the total actual in-service plant additions were $1,295,540,000. Thus, UGI Gas's plant in service performance as viewed by variance to budget can be shown to be over 1.6% ($1,295,540,000/$1,274,869,000) over the three-year period. This close correlation is indicative of the Company's ability to perform in developing a plan for plant additions and reliably executing to that plan. Importantly, the Company manages its budgets in total and as any budget changes are made dollars are reallocated between the four main budget categories, described above, such that the total plant additions align as close as possible to the total plant addition actuals.

Q. What process does UGI Gas utilize when developing its capital budgets?

A. During the Company's annual capital budget process, which occurs during the summer/fall, a two-year budget is prepared. The first year of the capital budget is the basis for the FTY. The second year is a preliminary budget and is the basis for the FPFTY. During the budget process, project managers estimate the total project costs and budgeted in-service dates at the project level based on the current data available. These estimated in-service dates are the basis for the budgeted plant additions as further discussed in the testimony of UGI Gas witness Vivian K. Ressler (UGI Gas Statement No. 3). As the Company transitions from one budget year to the next, and the preliminary budget year becomes the active budget year, the Company makes certain adjustments to its budget for known and measurable changes in the assumptions about operating conditions that supported the preliminary budget. For example, the Company adjusts its project lists on an annual basis based on operational demands, such as the need to reprioritize projects based on emerging service needs or unanticipated equipment condition changes.

Q. Did you calculate the percentage of plant additions accomplished by the Company during the three-year period reflected in UGI Gas Exhibit VAS-2?

A. Yes, I did. Exhibit VAS-2 compares plant additions placed in service (i.e., actuals) to the budgeted plant additions between 2022 and 2024. The exhibit provides these figures by the four above-described budget categories. It also separates them by distribution plant and general and common plant. Taken together, the distribution and general and common plant categories calculate total Plant Additions. Finally, the exhibit calculates plant in service as a percent of budget for each year and over the three-year period by dividing actuals by budgets.

Specifically, during this three-year period, the Company's plant additions were 101.6% of its budget. The percentage of plant additions is calculated by dividing the actual plant additions by the budgeted plant additions (Actual / Forecast). Thus, the Company has demonstrated that over a three-year period it has a documented history of meeting or exceeding its budgeted plant additions. This close correlation between budgeted and actual plant placed in service over a three-year period shows that UGI Gas's budget process is very effective at identifying its required plant additions, and supports the Company's claimed level of plant in service in this case.

IV. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VAS-1

Vicky A. Schappell

Senior Manager – Capital Planning

WORK EXPERIENCE

UGI Utilities, Inc. (Denver, PA)

Senior Manager – Capital Planning	May 2024-Present
Principal Analyst - Capital Planning	January 2020-May 2024
Senior Analyst - Capital Planning	April 2018-January 2020
Senior Supervisor Plant Accounting	December 2014-April 2018
Senior Analyst - General Ledger	September 2011-December 2014
Analyst II – General Ledger	September 2008-September 2011

Teleflex Medical (Reading, PA)

Accounting Supervisor	December 2007-September 2008
Senior Accountant – Financial Reporting	March 2003-December 2007
Staff Accountant – Financial Reporting	October 1999-March 2003

Heffler, Radetich & Saitta, LLP (Philadelphia, PA)

Auditor	May 1997-October 1999

Education

B.S. in Accounting, Shippensburg University,
1997

Previous Testimony

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Gas Base Rate Case	Docket No. R-2021-3030218
UGI Electric Base Rate Case	Docket No. R-2022-3037368

UGI GAS

EXHIBIT VAS-2

UGI UTILITIES, INC. - GAS DIVISION
Plant Additions Placed in Service Compared to Budget
$ amounts in '000s

Description	Budget 2024	Actual 2024	Budget 2023	Actual 2023	Budget 2022	Actual 2022	3 Year Total Budget	3 Year Total Actual
Natural Gas Production								
Replacement and Betterment							-	-
Subtotal Natural Gas Production	-	-	-	-	-	-	-	-
Transmission Plant								
Replacement and Betterment		(3)		(241)		(53)	-	(297)
Growth						(239)	-	(239)
Other				(71)		90	-	19
Subtotal Transmission Plant	-	(3)	-	(313)	-	(202)	-	(517)
Distribution								
Replacement and Betterment	259,662	243,367	317,228	302,171	281,270	293,795	858,161	839,333
Growth	67,452	68,926	67,961	92,260	69,493	77,289	204,906	238,475
Other	4,750	5,202	6,100	6,896	7,248	5,573	18,097	17,671
IT							-	-
Subtotal Distribution	331,864	317,496	391,289	401,327	358,011	376,657	1,081,164	1,095,479
General and Common Plant								
Replacement and Betterment	554	838	341	255	178	339	1,074	1,432
Growth							-	-
Other	33,504	34,384	52,960	48,386	26,375	30,937	112,839	113,708
IT	15,539	23,630	50,414	46,717	13,839	15,091	79,793	85,438
Subtotal General and Common Plant	49,598	58,852	103,715	95,358	40,392	46,368	193,705	200,578
Total Plant Additions	381,462	376,346	495,003	496,372	398,404	422,823	1,274,869	1,295,540
	(1)	**(2)**	**(1)**	**(2)**	**(1)**	**(2)**	**(1)**	**(2)**
Plant Additions Placed in Service as % of Budget	**(2) / (1)**	**98.7%**	**(2) / (1)**	**100.3%**	**(2) / (1)**	**106.1%**	**(2) / (1)**	**101.6%**

Forecasted Performance

Description	FPFTY Budget 2026	FTY Budget 2025
Distribution		
Replacement and Betterment	327,669	315,140
Growth	68,465	67,447
Other	9,750	6,731
Subtotal Distribution	405,885	389,317
General and Common Plant		
Replacement and Betterment	96	377
Growth	-	-
Other	20,525	17,132
IT	36,394	12,665
Subtotal General and Common Plant	57,014	30,174
Total Forecasted Plant Additions	462,899	419,491

BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 6 – PAUL R. MOUL
UGI GAS STATEMENT NO. 7 – DARIN T. ESPIGH
UGI GAS STATEMENT NO. 8 – SHERRY A. EPLER
UGI GAS STATEMENT NO. 9 – CHRISTOPHER R. BROWN
UGI GAS STATEMENT NO. 10 – JOHN D. TAYLOR

UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 55

DOCKET NO. R-2024-3052716

Issued: January 27, 2025 **Effective: March 28, 2025**

UGI GAS STATEMENT NO. 6

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed: **Capital Structure**
Rate of Return

Dated: January 27, 2025

UGI Utilities, Inc. - Gas Division
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
g	Growth rate
IGF	Internally Generated Funds
LDC	local distribution companies
Lev	Leverage modification
LT	Long Term
OCI	Other Comprehensive Income
P-E	Price-earnings
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor’s
UGI Gas	UGI Utilities, Inc. – Gas Division
UGI	UGI Corporation
V	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should recognize in determining the revenues UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") should be authorized to recover as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit B, which is a multi-page document consisting of Schedules one (1) through fourteen (14).

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. My conclusion is that the Company should be afforded an opportunity to earn an 8.42% overall rate of return, which includes an 11.20% rate of return on common equity. My 11.20% rate of return on common equity includes recognition of the exemplary performance of the Company's management and is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company.

My overall rate of return recommendation is determined by using the weighted average cost of capital approach. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall cost of capital when applied to the Company's rate base will provide a level of return which will compensate investors for the use of their capital. My overall cost of capital recommendation is set forth below and is shown on page 1 of Schedule 1.

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.89%	5.15%	2.36%
Common Equity	54.11%	11.20%	6.06%
Total	100.00%		8.42%

This overall rate of return is applicable to the September 30, 2026, fully projected future test year ("FPFTY") and the initial period that the Company's proposed rates will be effective.

Q. What factors concerning monetary policy have you considered in your analysis of the cost of equity for the Company?

A. Yes. My cost of equity analysis reflects the recent reductions in the Fed Funds rate implemented by the Federal Open Market Committee ("FOMC"). The FOMC uses its open market operations to control the Fed Funds rate as a means of implementing its dual mandate of healthy employment and price stability. The rate of inflation spiked upward after the Pandemic and has now fallen to a level that approaches the 2% policy goal of the FOMC. During its fight against high inflation, the FOMC increased the Fed Funds rate by 525 basis points through 11 increases in 17 months. The FOMC recently reduced the Fed Funds rate by fifty basis points on September 5, 2024. Additional rate reductions of twenty-five basis points each occurred on November 7, 2024 and December 18, 2024. Further, reductions in the Fed Funds rate are expected in 2025, but with less frequency. In spite of these reductions, the Fed Funds rate continues to be above levels experienced during the Pandemic. Furthermore, long-term interest rates measured by Treasury bond yields and the yields on A-rated public utility bonds remain at elevated levels. Relatively high interest rates have an impact on the level of economic activity, the cost of capital (particularly the interest cost of debt), and the need for more cautious financial practices, such as a prudent level of borrowing.

Q. Please describe the profile of the Company that you considered in your analysis.

A. UGI Gas is a division of UGI Utilities, Inc. ("UGI Utilities"), a wholly-owned subsidiary of UGI Corporation ("UGI" or the "Parent Company"). The Company provides natural gas distribution service to approximately 696,000 customers in forty-five (45) eastern and central Pennsylvania counties. The Company's service territory contains several production centers for basic industries involved in steel and aluminum manufacturing and fabrication, chemicals, and food processing.

Throughput to on-system customers in fiscal year 2023 was represented by approximately 17% to sales customers and approximately 83% to transportation customers. The significant portion of the Company's throughput to industrial customers (70% of total throughput) makes the Company a much higher risk utility as compared to the Gas Group. The Company obtains its natural gas supplies from producers and marketers and has transportation arrangements through connections to several interstate pipelines and storage facilities. The Company has storage arrangements for natural gas inventory. UGI Utilities also provides electric delivery service, through UGI Electric, to more than 62,700 customers in portions of Luzerne and Wyoming Counties.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for a natural gas utility, such as UGI Gas. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 11.20%, including 0.20% in recognition of the Company's exemplary management performance.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of companies engaged in the distribution of natural gas. I will refer to these companies as the "Gas Group" throughout my testimony. I began with all of the gas utilities contained in the basic service of The Value Line Investment Survey, which consists of nine companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. However, I eliminated one (1) company from the Value Line group. UGI was removed due to its diversified businesses

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

consisting of six (6) reportable segments, including propane, two (2) international LPG segments, natural gas utility, energy services, and electric generation. The remaining eight (8) companies in the Gas Group are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity models in the recent Quarterly Earnings Report approved by the Commission on October 10, 2024 (see Docket Number M-2024-3051104).

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the methods/models for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF	10.96%
Risk Premium	11.25%
CAPM	13.00%
Comparable Earnings	12.40%

From these measures, I recommend a cost of equity of 11.00%, to which 0.20% should be added in recognition of the Company's exemplary management performance. My recommendation is on the conservative side for UGI Gas because it is based on the Gas Group that does not have the Company's high-risk attributes related to its high level of industrial throughput. Focusing upon the DCF and Risk Premium approaches of the cost of equity, the average equity return is 11.11% (10.96% + 11.25% = 22.21% ÷ 2). After removing the leverage adjustment from the DCF model, the average results are 10.63% (10.01% + 11.25% = 21.26% ÷ 2). The 11.00% equity return that I propose in this case rests between these measures, i.e., 10.63% and 11.11%. Indeed, the 11.00% cost of equity determined here is very conservative because it is well below the average of the market-based models, i.e., DCF, Risk Premium and CAPM, that provide a return of 11.73% (10.96% + 11.25% + 13.00% = 35.21% ÷ 3 = 11.73%). My 11.20% cost of equity recommendation includes 20 basis points, or 0.20%, in recognition of the exemplary performance of the Company's management and falls within the overall range of 10.96% to 13.00% indicated above by each model. Mr. Bell's testimony (UGI Gas Statement No. 1) demonstrates that the Company ranks high in customer service and management effectiveness. To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Along these lines, the Company is spending considerable amounts of new capital, which will put a strain on financial performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn an 11.20% rate of return on common equity.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of natural gas utilities?

A. Natural gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers. The gas distribution industry also faces the risk associated with increased availability of renewable energy sources, expanded emphasis on energy efficiency, and potential initiatives directed toward decarbonization as a national energy policy.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of Company witnesses Schappell and Brown discusses the investments that the Company has made and will continue to make to address these issues and expansion requests, which have led to increased external capital requirements.

Q. Does the Company face competition in its natural gas business?

A. Yes. The Company's service territory is within or in close proximity to the Marcellus Shale production area, which provides additional risk for it compared to many companies in the Gas Group. Natural gas utilities generally face significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory. Propane and fuel oil have an advantage because they are not inhibited by regulatory constraints when conducting marketing and pricing their services. This situation is unlike that of UGI Gas, where specific thresholds must be satisfied for system expansions, where promotional activities are constrained and prices are regulated. The Company also faces the risk associated with throughput to interruptible customers whose deliveries are influenced by global oil prices. Further, the Company has identified seventeen (17) customers that could potentially bypass its system.

Q. What are the risks associated with the Company's large volume customers?

A. The Company's risk profile is strongly influenced by throughput delivered to large competitive market customers. Industrial customers represent 68% of throughput, but these customers represent about one-half of one percent of total customers. Moreover, the Company's top ten (10) customers represent 187 million Mcf of total throughput or about 57% of the total. Electric generation and manufacturing are among these customers. Steel and aluminum manufacturing and fabrication face a number of challenges including international competition, increased costs, and fluctuating demand for their products. Industrial sales are generally higher in risk than sales to other classes of customers. Success in this segment of the Company's market is subject to the business cycle and the price of alternative energy sources. Moreover, external factors can also influence the Company's sales to these customers, which face competitive pressures on their own operations from other facilities outside the Company's service territory.

Q. Please discuss some of the operational risks faced by the Company?

A. Risks that affect the Company's operations relate to adequate delivery capability, counterparty risk, and risks related to cyber-security. The Company is also faced with counterparty risk should suppliers fail to perform their obligations, especially with regard to hedging obligations. In addition, the handling of natural gas is inherently risky. Finally, cyber-security has created increased risk when systems that deliver gas to customers are vulnerable to attack from foreign enemies and domestic terrorists.

Q. What risks are associated with the Company's infrastructure?

A. The Company's infrastructure is aging and is in the process of rehabilitation and replacement. Investments that address these issues cause costs to increase without any corresponding increase in throughput that would add to revenues. This places pressure on the price paid by customers that may prompt them to seek alternative energy sources.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. With customer demand for the Company's service at high levels, the Company is faced with the requirement to invest in new facilities to meet growth and to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its existing facilities. The Company had 800 miles of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2023. The Company also has 15,425 of its services constructed of unprotected steel. The Company is also under a regulatory mandate to relocate all of its meters outside, with certain exceptions, by September 13, 2034. The continuing costs for upgrading the Company's pipe system will elevate the level of construction expenditures. In the situation where additional capital investment is required to replace existing facilities and also to serve new customers, supportive regulation is a necessary prerequisite for the Company to actually achieve a fair rate of return and attract new capital on reasonable terms.

For the future, the Company estimates that its total construction expenditures will be:

Year	Capital Expenditures
2025	$ 465,000,000
2026	$ 530,000,000
2027	$ 608,000,000
2028	$ 632,320,000
2029	$ 657,612,800
Total	$ 2,892,932,800

Of these amounts, $2,725,000,000 are attributed to the Gas Division. During the 2025-2029 period, gross construction expenditures will represent an approximate 67% increase ($2,892,932,800 ÷ $4,322,119,002) in net utility plant, including construction work in progress, from the level at September 30, 2024.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. Therefore, a large proportion of the Company's residential and commercial customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To help deal with this issue, UGI Gas has implemented a weather normalization adjustment ("WNA") mechanism as part of its tariff.

Q. Does your cost of equity analysis and recommendation take into account the WNA decoupling mechanism?

A. Yes. The Company has a weather normalization mechanism that it obtained in its last rate case. My cost of equity analysis takes into account the Company's WNA mechanism.

Q. How have you addressed this issue?

A. My analysis reflects the impact of the WNA on investor expectations through the use of market-determined models. All of the companies in my Gas Group have some form of WNA mechanism that is intended to accomplish the same result as the Company's WNA. As a group, the market prices of these companies' common equity reflect the expectations of investors that the companies' revenues are stabilized to some extent by a WNA. Therefore, my analysis reflects the impacts of decoupling on investor expectations through the use of market-determined models.

As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of these mechanisms in the LDC business. Because the Gas Group that I use to measure the cost of equity has the risk attributes related to the revenue decoupling mechanism "baked in" to their stock prices, if the WNA did not exist for UGI Gas, it would increase the cost of equity for the Company as determined by the models that are applied with the Gas Group data.

Q. Is the Company's risk also affected by the substantial decline in usage per customer?

A. Yes. Despite adding new customers, usage per residential heating customer continues to decline over time as is shown in UGI Gas Exhibit SAE-3 and discussed in the testimony of Sherry A. Epler (UGI Gas Statement No. 8). Company analysis indicates that this decline will continue, particularly with the implementation of additional efficiency and conservation plans that benefit customers and further reduce usage. This plan provides many benefits to customers and to the public, but can be expected to further reduce customer usage and consequently Company revenues and return.

Q. Are you aware that there is a DSIC available to natural gas utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company has utilized the Distribution System Improvement Charge ("DSIC") in the past. The cost of capital for UGI Gas, however, is not affected by the DSIC. I say this because most of the proxy group companies (i.e., eight (8) of nine (9) companies) whose data has been used to develop the cost of equity for UGI Gas in this proceeding have a DSIC or similar infrastructure rehabilitation mechanisms. Indeed, Atmos Energy, Chesapeake, New Jersey Resources, NiSource, Northwest Natural Gas, Southwest Gas, and Spire make use of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. How should the Commission respond to the issues facing the natural gas business and in particular UGI Gas?

A. The Commission should recognize the issues listed above when deciding the rate of return issue in this case. In particular, the Company has higher risks associated with its large throughput to industrial customers. Another risk is declining usage per customer discussed in the testimony of Company witness Sherry A. Epler (UGI Gas Statement No. 8). Moreover, the Company requires regulatory support at a time of increased infrastructure spending now underway for the Company.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon Company risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What companies comprise the Gas Group?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., Southwest Gas Holdings, and Spire, Inc.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the credit quality ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer credit quality rating is A2 from Moody's Investors Service ("Moody's") and A- from Fitch. The rating represents the LT issuer rating by Moody's, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself. For the Gas Group, the average LT issuer rating is A3 by Moody's and A- by Standard & Poor's, as displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by Standard & Poor's, as displayed on page 3 of Schedule 4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2019-2023. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for UGI Gas as compared to the Gas Group and the S&P Public Utilities.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

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[2]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

There are no market ratios available for the Company because its stock is owned by UGI. The five-year average price-earnings multiple for the Gas Group was slightly higher than that of the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio for the Gas Group was lower as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). A firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 54.3% for UGI Gas, 47.4% for the Gas Group, and 39.7% for the S&P Public Utilities. The Company's common equity ratio was higher than the Gas Group, thereby indicating somewhat lower financial risk. However for the purpose of this case, the Company's common equity ratio is within the range of other gas distribution utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.070 (0.8% ÷ 11.4%)

for the Company, 0.087 (0.8% ÷ 9.2%) for the Gas Group, and 0.050 (0.5% ÷ 10.1%) for the S&P Public Utilities. The variability of the Company's rates of return was below the Gas Group and higher than the S&P Public Utilities, thereby signifying higher risk for the Company compared to the S&P Public Utilities and somewhat less risk compared to the Gas Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 78.1% for the Company, 82.1% for the Gas Group, and 80.9% for the S&P Public Utilities. The Company's operating ratios were somewhat lower than the Gas Group, thereby indicating slightly lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 4.65 times for the Company, 4.24 times for the Gas Group, and 2.90 times for the S&P Public Utilities. The interest coverages were higher for the Company as compared to the Gas Group, thereby indicating lower credit risk.

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 71.2% for the Company, 57.0% for the Gas Group, and 59.0% for the S&P Public Utilities. The Company's IGF to construction expenditures benefited in 2023 and 2022 from the absence of common dividend payments.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

Value Line beta of 0.88 as the average for the Gas Group (see page 2 of Schedule 3) and 0.94 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. Please summarize your risk evaluation.

A. The investment risk of UGI Utilities parallels that of the Gas Group in certain respects. In certain regards, principally related to its small size and large throughput to industrial customers, UGI Utilities has higher risk traits. UGI Utilities has lower risk as shown by its higher common equity ratio, somewhat less variable earned returns, its lower operating ratio, and higher interest coverages. On balance, the cost of equity measured with the Gas Group data will provide a reasonable, albeit conservative, representation of the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGI Utilities in this case.

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGI Utilities, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of the capital employed, and the capital cost rates are directly identifiable. I have employed the capital structure ratios of UGI Utilities to calculate the rate of return for this case because it finances all its operations on a consolidated basis. The circumstances of UGI Gas indicate that the capital structure ratios of UGI Utilities should be used for rate of return purposes for both its utility divisions.

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents UGI Utilities' capitalization and related capital structure at September 30, 2024, the end of the historic test year ("HTY"). Also shown on Schedule 5 is the UGI Utilities' capital structure estimated at September 30, 2025, the end of the future test year ("FTY"), and at September 30, 2026, the end of the FPFTY. The changes in UGI Utilities' capital structure consist of: (i) debt maturities and principal payments of $287.5 million in both the FTY and FPFTY, (ii) the issuance in four (4) series of $525 million debt issues in both the FTY and FPFTY, (iii) the receipt of $50 million of capital contributions in the FTY and FPFTY, and (iv) the Company's projection of retained earnings at the end of the FTY and FPFTY.

Q. Have you made adjustments to the Company's capitalization for rate-setting purposes?

A. Yes. I have removed accumulated other comprehensive income ("OCI") from the Company's common equity account.

Q. Please explain the justification for removing the accumulated OCI?

A. The accumulated OCI must be eliminated from the capital structure for rate setting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and with derivative instruments associated with commodity contracts and interest rate hedges. An MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. It should be noted that the Company records the change related to prior service cost and actuarial valuations as a regulatory asset for the portion of pension attributable to its retirees and employees that are part of its regulated utility operations. The amount in the accumulated OCI is related to the portion attributable to employees of UGI and non-utility subsidiaries. That is to say, the accumulated OCI associated with MPL is not related to utility operations.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. I will adopt the UGI Utilities' capital structure ratios at the end of the FPFTY, which consists of 45.89% long-term debt and 54.11% common equity. These ratios are within the ranges indicated for the Gas Group. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

Q. Have you included short-term debt as a component of the Company's capital structure in the case?

A. No. I have considered the issue of short-term debt, but I have rejected its use here. The Company uses short-term debt to finance non-rate base items. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the HTY, the FTY, and the FPFTY and compared those amounts to the Company's construction work in progress ("CWIP") and non-trade receivables. I have done this because the Company follows the FERC formula to calculate its AFUDC ("Allowance of Funds Used During Construction rate"). That formula assigns short-term debt first to CWIP, with any excess balance of CWIP receiving the Company's overall rate of return. In order to avoid double-counting the amount of short-term debt that finances CWIP, those amounts must be removed from the average short-term debt amounts for rate case purposes. That is to say, the use of short-term debt for AFUDC decreases the overall cost of construction that ultimately goes into rate base so ratepayers ultimately receive the benefit for this lower cost capital. Moreover, the Company has other assets on its balance sheet that require short-term financing such as non-trade receivables. It is reasonable to assume that short-term debt represents the source of funds used to finance these costs that are not in the rate base. Likewise, non-trade receivables do not receive a return because they are not in rate base and incur no interest cost. As a consequence, no amount of short-term debt can be assumed to finance the rate base in this case.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. Consistency requires that the embedded senior capital cost rates of UGI Utilities must be used for developing a fair rate of return for the Company. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that UGI Utilities has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2024. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2025. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

The interest rates for the four (4) new issues of debt in the FTY and FPFTY are 5.520% for the 10-year issues. With these rates, I calculate a 5.15% forecast embedded long-term debt cost rate at September 30, 2026, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5, which provides the basis for the 45.89% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGI Gas, the Gas Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage and bond ratings, must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.20% for UGI Gas.

DISCOUNTED CASH FLOW

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 10.96% with the leverage adjustment and 10.01% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance. And, indeed, the FERC has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950s, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

equity. For the 12 months ended October 2024, the monthly dividend yields are shown in Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the 12 months ended October 2024, the average dividend yield was 3.78% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.64% and 3.53%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.64% for the Gas Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different but generally accepted manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7.[6] This adjustment adds 12 basis

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[6] These adjustments are the 1/2 growth approach, the discrete approach and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)* results in this third DCF formulation. This DCF equation

points to the six-month average historical yield, thus producing the 3.76% adjusted dividend yield for the Gas Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus on prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares that the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

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provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage during which a firm enjoys rapidly expanding markets, high profit margins and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, investment opportunities begin to mature, capital requirements decline and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps up and ramps down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle but rather to rely upon analysts' growth forecasts used by investors when pricing common stocks.

Q. What factor should be considered in the determination of an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the P-E multiple. As such, my company-specific growth analysis, which focuses principally on five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Schedule 9.

Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.86%), Zacks (6.00%) and Value Line (6.56%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While various factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[7] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.86% to 6.56%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my

[7] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

opinion, a growth rate of 6.25% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 41.52% long-term debt, 0.73% preferred stock, and 57.75% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate-setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[8] provide a return of 8.36% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed, the stock prices of non-regulated companies exceed

[8] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 8.36%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.56% to compensate investors for the risk of 52.71% debt ratio and 0.04% for a 0.77% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 10.96% (8.36% + 2.56% + 0.04%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.76% dividend yield, the 6.25% growth rate, and 0.95% for the leverage adjustment to arrive at the same 10.96% return computed directly with the "M&M" formula. I know of no means to mathematically solve for the 0.95% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.95% adjustment is merely a convenient way to compare the 10.96% return computed using the Modigliani & Miller formulas to the 10.01% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF shown on Schedule 7) based on a market-value capital structure. A 10.01% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 10.96%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	k
Gas Group	3.76%	+	6.25%	+	0.95%	=	10.96%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.25%.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 4.75% yield represents a very conservative estimate of the prospective yield on long-term, public utility bonds.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the 12 months ended October 2024 the average monthly yield on Moody's index public utility bonds was 5.56%. For the six- and three-month periods ended October 2024, the yields were 5.50% and 5.33%, respectively. During the 12 months ended October 2024, the range of the yields on A-rated public utility bonds was 5.20% to 5.96%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.18% on a 12-month average basis, 1.15% on a six-month average basis, and 1.14% on a three-month average basis. With these data, 1.00% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of various interest rates compiled from a panel of banking, brokerage and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on November 1, 2024, and a yield spread of 1.00%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I have also shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2024	Fourth	5.0%	5.8%	4.3%	1.00%	5.30%
2025	First	4.9%	5.8%	4.2%	1.00%	5.20%
2025	Second	4.9%	5.8%	4.2%	1.00%	5.20%
2025	Third	4.9%	5.8%	4.2%	1.00%	5.20%
2025	Fourth	4.9%	5.8%	4.2%	1.00%	5.20%
2026	First	4.9%	5.8%	4.2%	1.00%	5.20%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its August 30, 2024 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2026-2030	5.2%	6.1%	4.3%
2031-2035	5.2%	6.2%	4.4%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 4.75% yield on A-rated public utility bonds represents a reasonably conservative benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 12.

Common Equity Risk Premiums	
Low Interest Rates	7.13%
Average Across All Interest Rates	5.96%
High Interest Rates	4.76%

Based on my analysis of the historical data, the equity risk premium was 7.13% when the marginal cost of long-term government bonds was low (i.e., 2.83%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 4.76%. Over the entire spectrum of interest rates, the equity risk premium was 5.96% when the average government bond yield was 4.93%. From this data, I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% is between the premiums associated with low interest rates (i.e., 7.13%) and average for the entire historical period interest rates (i.e., 5.96%).

Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP").

The Risk Premium approach provides a cost of equity of:

	i	+	***RP***	=	***k***
Gas Group	4.75%	+	6.50%	=	11.25%

CAPITAL ASSET PRICING MODEL

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 13.00% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 11.54% (13.00% - (0.19 x 7.69%)) through use of the Value Line beta excluding the leverage adjustment (i.e., 1.07 - 0.88 = 0.19). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β") and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.88 for the Gas Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage-adjusted betas that I used in the CAPM. The Value Line betas are measured over a five-year period.

The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[9] as follows:

$$\beta l = \beta u \, [1 + (1 - t) \, D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.56 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.07 for the book value capital structure of the Gas Group.

[9] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks;" The Journal of Finance, Vol. 27, No. 2; Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, Dec. 27-29, 1971. (May 1972), pp. 435-52.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13 I provided the historical yields on Treasury notes and bonds. For the 12 months ended October 2024, the average yield on 30-year Treasury bonds was 4.38%. For the six- and three-months ended October 2024, the yields on 30-year Treasury bonds were 4.35% and 4.19%, respectively. During the 12 months ended October 2024, the range of the yields on 30-year Treasury bonds was 4.04% to 4.66%.

The low yields that existed prior to 2022 can be traced to extraordinary events associated with the Pandemic that jolted the capital markets. Since then, higher rates took place. Higher inflation during the period was a contributing factor that prompted the FOMC to raise the Fed Funds rate from the low levels that existed during the Pandemic.

Due to high inflation rates above the policy goal of the FOMC, the accommodative policy was ended by the FOMC in the first quarter of 2022. A tighter monetary policy began at that time, which caused higher interest rates. In March 2022, the FOMC began process of running off its $9 trillion asset portfolio, which will keep interest rates at elevated levels after the Pandemic. As noted previously, the FOMC changed course and recently reduced the Fed Funds rate to support the job market that is the second part of its dual mandate.

High interest rates clearly point to high capital costs prospectively. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, for the first time since late 2018. By October 2024, the yield on 30-year Treasury bonds moved to 4.38%, or an increase of 2.71% (or 162%) since December 2020.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on November 1, 2024, indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.2% to 4.3% during the next six quarters. This means that elevated interest rates will continue near current levels into 2025. The longer-term forecasts show that the yields on 30-year Treasury bonds will average 4.3% from 2026 through 2030 and 4.4% from 2031 to 2035. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a conservative 3.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 12.21% (12.40% + 12.02% = 24.42% ÷ 2) as the midpoint of the "low" and "average" interest rate environments. During those periods, the yield on long-term government bonds was 3.87% (2.83% + 4.91% = 7.74% ÷ 2). The resulting market premium is 8.34% (12.21% - 3.87%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show a 10.78% total market return based on the <u>Value Line</u> forecasts. With these data, I calculated a market premium of 7.03% (10.78% - 3.75%) using the forecast data by Value Line. The resulting market premium applicable to the CAPM derived from these sources equals 7.69% (7.03% + 8.34% = 15.37% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Eugene F. Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could significantly understate the cost of equity according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation. The adjustment here is related to the size of the Gas Group.

Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 1.07 for the Gas Group, the 7.69% market premium, and the 1.02% size adjustment, the following result is indicated:

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*
Gas Group	3.75%	+	1.07	x (	7.69%	) +	1.02%	=	13.00%

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works v. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach to cover conditions over an entire business cycle. A 10-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.3% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return, as published by Value Line, is 12.5% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data, my Comparable Earnings result is 12.40%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of various methods and models described previously, it is my opinion that the reasonable cost of common equity is 11.20% for the Company that includes recognition of its exemplary management performance. My proposed cost of equity will accommodate the Company's small size and its business risk characteristics. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-one years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water

Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Commission of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

UGI GAS STATEMENT NO. 7

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Darin T. Espigh

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 27, 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Darin T. Espigh. My business address is One UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your principal duties and responsibilities as Senior Manager Natural Gas Tax Accounting for UGI Corp.?

A. My primary duties as Senior Manager Natural Gas Tax Accounting include the preparation of tax data to be reported in UGI Corp.'s various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage the reporting of UGI's various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and professional experience.

A. They are set forth in my resume attached as UGI Gas Exhibit DTE-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2026 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2024 ("HTY") and future test year ending September 30, 2025 ("FTY").

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit DTE-1 contains a list of those proceedings.

Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the UGI Gas Exhibits: DTE-1, DTE-2, DTE-3. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related items. These exhibits comprise UGI Gas's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests as indicated on the master list accompanying this filing.

II. TAX ADJUSTMENTS

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY. Section D of UGI Gas Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the HTY and the FTY. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with adjusted actual book results from the HTY and adjusted FTY results. UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31, include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), Pennsylvania and Local Property taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the

Commission, Office of Consumer Advocate and Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2). These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $248,000 is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Gas Exhibit A (Fully Projected), Schedule D-33. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow-through of accelerated depreciation benefits for state tax purposes. UGI Gas is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas continues to flow through the repairs tax benefit over the tax useful lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Gas Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe how Schedule D-33 calculates the Company's claim for income taxes shown on Schedule D-1, lines 19 and 20.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 20. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Schedule D-33, line 1 shows revenue at present and proposed rates, while line 2 shows operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI Gas's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas Statement No. 6) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from operating income before interest and taxes to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9, which appears as ($163,056) on line 10. Next, the statutory state corporate net income tax rate was applied (as further described below in Section F of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Regarding the pro forma federal income tax expense, lines 14 through 19 show the calculation at current and proposed rates. Next, line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates, with the total calculated amount for income taxes, before the application of other adjustments, shown on line 29, which shows the net income tax expense. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Gas?

A. As shown on Schedule D-33 at line 31, the *pro forma* combined income tax expense at present rates is $45.6 million and the *pro forma* tax expense at proposed rates for the FPFTY is $75.2 million. As explained below in Section E, this figure is not required to be reduced by a consolidated income tax adjustment. Moreover, the pro forma income tax at present rates and the pro forma income tax revenue increase calculated in Schedule D-33 appear in Schedule D-1, which comprises the Company's claimed income tax expense.

Q. Has the Company reflected the amortization of Excess Deferred Federal Income Taxes ("EDFIT"), as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"), on its income tax expense claim?

A. Yes, the Company has calculated the amount of the EDFIT that would be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on line 25 of Schedule D-33. The total amortization was approximately $4.3 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT as of September 30, 2026. This amount is deducted from rate base. The total shown on line 9 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was further reduced by the state regulatory liability associated with UGI Gas's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 9 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $687.7 million, which includes the amount related to EDFIT.

Q. Does the Company's reduction to rate base include EDFIT?

A. Yes, the Company has reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 9 of Schedule C-6.

Q. Has the Company's ADIT rate base deduction been calculated in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Gas Exhibit DTE-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

Q. Please explain UGI Gas's accounting treatment of the Repairs Tax Method.

A. In its tax return for the year ended September 30, 2009, UGI Gas adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2021-3030218, UGI Gas chose to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Gas has chosen to flow through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a federal consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes.

A calculation of the consolidated tax adjustment for that purpose, using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40, is included in the Company's filing as Attachment II-A-26 and UGI Gas Exhibit DTE-3. Company witness Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2) discusses how the Company has satisfied the requirements of Act 40.

F. PENNSYLVANIA TAX RATE CHANGE

Q. Are you familiar with the recently enacted Pennsylvania corporate net income tax rate change?

A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which reduced the state corporate net income tax rate from the then-current 9.99% to 4.99% over a nine-year period. The initial reduction to 8.99% was effective for tax years beginning in calendar year 2023. Thus, the initial reduction applied to Fiscal Year End September 30, 2024, which is the Company's HTY.

Q. How has the Company accounted for the recently enacted Pennsylvania tax rate change?

The Company's claim for income taxes reflects the applicable state tax rate in effect for the HTY (i.e., 8.99%), FTY (i.e., 8.49%) and FPFTY (i.e., 7.99%). As explained above, the initial reduction applied to our HTY. The State Tax Adjustment Surcharge ("STAS") mechanism will adjust the Company's rates as applicable for future reductions to the state corporate net income tax rate.

Q. How is the Company applying the Pennsylvania corporate net income tax rate change to its Repairs Tax method?

A. Consistent with historic treatment as described in Section D of this testimony, the Company's state regulatory liability associated with its repairs tax method will continue to represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA ***March 2022 - Present***
Senior Manager of Natural Gas Tax Accounting

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. Supervise 2 direct reports.

JBS USA, Greeley, CO ***2014 – March 2022***
Senior Tax Manager, Tax Accounting and Global Reporting

Manage tax accounting and reporting under ASC 740 including effective rate development, perm development, valuation allowances, ABP 23 indefinite reinvestment assertions, financial statement footnotes, management of global deferred inventory and FIN48/FAS 5 analysis for international consolidated financial statements. Responsible for IFRS adjustments and reporting package to Brazilian parent company. Interface with internal and external auditors. Managed tax accounting aspects of a large global reorganization. Design and streamline provision reporting packages to meet increased demands of public reporting.

Managed both federal and state income tax compliance. Responsible for attribution memos related to the preparation of Form 5472, R&D Credits, Sec 163(j), Schedule G and Schedule O compliance for more than 10 separate federal tax returns. Supervised income tax audits. Managed documentation and notice requirements related to the Foreign Investment in Real Property Tax Act (FIRPTA) related to distributions of U.S. real property interests by foreign corporations. Managed, trained and developed staff in tax accounting and financial reporting and compliance.

UGI UTILITIES, INC., Reading, PA ***2007 to 2014***
Senior Tax Analyst

Responsible for quarterly and annual tax accounting and reporting under ASC 740 including effective rate development, maintenance and classification of deferred inventory balances and account reconciliations. Calculate annual provision to return adjustment for year-end provision. Interface with internal and external auditors on tax related matters. Provide budget and forecast amounts for all tax related items. Preparation of tax data to support external regulatory reporting including Base Rate Case filings.

Preparation of income tax return support submitted to corporate for inclusion in the consolidated income tax return. Responsible for indirect tax compliance.

BERTZ & COMPANY, CPA's, Lancaster, PA ***2000 to 2007***
Senior Associate

Responsible for preparation of individual, corporate, partnership, nonprofit and payroll tax returns. Charged with the preparation of financial statements including required disclosures for a wide range of industries including construction, hospitality and retail food establishments. Supervised, trained and developed staff on client engagements.

Managed audit engagements of retirement plans and homeowner associations. Gained experience on a variety of other audits.

HATTER, HARRIS & BEITTEL, LLP, Lancaster, PA ***1994 to 2000***
Senior Associate

Prepared individual, corporate, partnership, nonprofit and payroll tax returns. Managed review and compilation engagements. Managed nonprofit audit. Developed significant experience in audits of school districts, retail and manufacturing businesses. Gained strong working knowledge of financial statements and related disclosures for engagements of all levels. Trained and developed new staff.

EDUCATION & CREDENTIALS

Bachelor of Science in Accounting – Messiah College, Grantham, PA – May 1994

Certified Public Accountant

Previous Testimony:

UGI Electric Base Rate Case	Docket No. R-2022-3037368

UGI GAS

EXHIBIT DTE-2

UGI Utilities, Inc. - Gas Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2022					$ 675,838
10/31/2022	3,521	335	91.78%	3,231	679,070
11/30/2022	1,087	305	83.56%	909	679,978
12/31/2022	1,425	274	75.07%	1,070	681,048
1/31/2023	721	243	66.58%	480	681,528
2/28/2023	758	215	58.90%	446	681,974
3/31/2023	2,028	184	50.41%	1,023	682,997
4/30/2023	880	154	42.19%	371	683,368
5/31/2023	1,087	123	33.70%	366	683,735
6/30/2023	4,265	93	25.48%	1,087	684,821
7/31/2023	3,097	62	16.99%	526	685,347
8/31/2023	2,187	31	8.49%	186	685,533
9/30/2023	8,903	1	0.27%	24	**$ 685,557**

UGI GAS

EXHIBIT DTE-3

UGI Utilities, Inc. - Gas Division
Calculation of Consolidated Tax Adjustment
For the Years Ended September 30, 2021, 2022 and 2023
In Thousands (000)

	Taxable Income 2021	Taxable Income 2022	Taxable Income 2023	Average		
Tax Loss Entities						
AmeriGas Propane Holdings, Inc.	0	0	0	0		
Ashtola Production Company	(1)	(2)	(1)	(1)		
Hellertown Pipeline	0	0	0	0		
Homestead Holding	(76)	(406)	(2,687)	(1,057)		
Mountaineer Gas Company	0		(7,762)	(2,587)		
Mountaintop Energy Holding Inc	0	(29)	(33)	(21)		
UGI Hunlock Dev	0	0	0	0		
UGI HVAC Enterprises	(1,556)	0	0	(519)		
UGI LNG	(3,679)	0	0	(1,226)		
UGID Holding Company	(8)	(5)	(3)	(5)		
Newberry Holding	0	(56)	0	(19)		
United Valley Insurance	0	0	0	0		
UGI Corporation	0	0	(10,953)	(3,651)		
AmeriGas Inc	0	0	0	0		
UGI China Inc	0	0	0	0		
UGI International China. Inc	0	0	0	0		
UGI Penn HVAC Services	0	0	0	0		
UGI Properties, Inc.	0	0	0	0		
UGI Development Company	(4,031)	(1,144)	0	(1,725)		
UGI Enterprises Inc	0	0	0	0		
Subtotal Taxable Loss	**(9,351)**	**(1,642)**	**(21,439)**	**(10,811)**		
Tax Positive Entities					% of Total	CTA
AmeriGas Propane Inc.	30,085	**30,246**	**25,944**	28,759	7.2%	(774)
AmeriGas Propane Holdings, Inc.	122,728	**136,844**	**123,819**	127,797	31.8%	(3,439)
AmeriGas Inc.	178	**18**		65	0.0%	(2)
Amerigas Technology Group Inc.	0			0	0.0%	0
Energy Service Funding	4,656	**5,385**	**10,721**	6,921	1.7%	(186)
Mountaineer Gas Company	0	**4,636**		1,545	0.4%	(42)
Newberry Holding	120		**35**	52	0.0%	(1)
Petrolane Incorporated	0			0	0.0%	0
UGI China, Inc.	0			0	0.0%	0
UGI Corporation	23,110	**61,904**	**0**	28,338	7.1%	(763)
UGI Development Company	0		**8,658**	2,886	0.7%	(78)
UGI Enterprises, Inc.	0			0	0.0%	0
UGI Europe, Inc.	42,637	70,069	101,886	71,531	17.8%	(1,925)
UGI HVAC Enterprises	0	53		18	0.0%	(0)
UGI LNG	0	4,837	4,402	3,080	0.8%	(83)
UGI Penn HVAC Services	0			0	0.0%	0
UGI Properties, Inc.	438	532	11,716	4,229	1.1%	(114)
UGI Storage Company	4,997	5,138	19,858	9,997	2.5%	(269)
UGI Utilities, Inc.	62,490	105,893	180,897	116,427	29.0%	(3,133)
UGI International Enterprises, Inc.	0			0	0.0%	0
United Valley Insurance	146	97	141	128	0.0%	(3)
Eliminations	0			0	0.0%	0
Subtotal Taxable Income	**291,584**	**425,652**	**488,077**	**401,771**	100.0%	(10,811)
Total Taxable Income	**282,233**	**424,010**	**466,638**	**390,960**		

Tax Savings Applicable to UGI Utilities, Inc.	(3,133)
MWF Allocation % for UGI Gas	89.89%
Total Tax Savings Allocated to UGI Gas	(2,816)
Federal Tax Rate	21%
Total Consolidated Tax Adjustment	**(591)**

Notes:
1. Single-member limited liability companies, i.e. disregarded entities, have been combined with their tax-regarded parent company.

Tax Loss Entities	Taxable Income 2023	Adjustments		Adjusted Taxable Income
UGI Corporation	(156,912)	145,959	(1)	(10,953)
AmeriGas Inc				0
AmeriGas Propane Holdings, Inc.	(153,159)	276,978	(2)	123,819
Amerigas Technology Group Inc.				0
Ashtola Production Company	(1)			(1)
Eastfield International Holdings Inc				0
EuroGas Holdings Inc.				0
Four Flags Drilling Company				0
Hellertown Pipeline				0
Homestead Holding	(2,687)			(2,687)
Mountaineer Gas Company	(7,762)			(7,762)
Mountaintop Energy Holding Inc	(8,511)	8,478	(3)	(33)
Newberry Holding				0
UGI Asset Management				0
UGI Black Sea Enterprises				0
UGI Development Company				0
UGID Holding Company	(3)			(3)
UGI Energy Ventures, Inc.				0
UGI Ethanol Development Company				0
UGI Enterprises Inc				0
UGI Hunlock Dev				0
UGI HVAC Enterprises				0
UGI International China. Inc				0
UGI International (Romania)				0
UGI LNG				0
UGI Penn HVAC Services				0
UGI Petroleum Products of DE				0
UGI Romania, Inc.				0
UGID Holding Company				0
Total Tax Loss	(329,035)	431,415		102,380

Explanations of Adjustments:

(1) Within UGI Corporation there is interest related to the 2019 AmeriGas acquisitio	51,595
UGI Corporation includes it's entire chain of LLC's.Within those LLC's:	
UGI International LLC has hedge losses	6,790
Interest expense related to foreign operations	27,296
UGI PennEast LLC one-time partnership loss due to ceasing business	55,670
Tax Losses in other partnerships - due to Tax > Book Depr in early years.	4,608

(2) Equity pick-up from AmeriGas partnership includes amortization of step-up from acquisition.
Acquisition was in August 2019. Amortization of step up runs 39 years (although most falls off after year 9)

(3) This $8.5 MM is the utilization of a §382 limited NOL that comes into the UGI Corporation consolidated return as the result of the Mountaineer Gas Company acquisition on September 1, 2021.

Tax Loss Entities	Taxable Income 2022	Adjustments		Adjusted Taxable Income
UGI Corporation				0
AmeriGas Inc				0
AmeriGas Propane Holdings, Inc.	(144,954)	281,798	(1)	136,844
Amerigas Technology Group Inc.				0
Ashtola Production Company	(2)			(2)
Eastfield International Holdings Inc				0
EuroGas Holdings Inc.				0
Four Flags Drilling Company				0
Hellertown Pipeline				0
Homestead Holding	(406)			(406)
Mountaineer Gas Company				0
Mountaintop Energy Holding Inc	(8,507)	8,478	(2)	(29)
Newberry Holding	(56)			(56)
UGI Asset Management				0
UGI Black Sea Enterprises				0
UGI Development Company	(1,144)			(1,144)
UGID Holding Company	(5)			(5)
UGI Energy Ventures, Inc.				0
UGI Ethanol Development Company				0
UGI Enterprises Inc				0
UGI Hunlock Dev				0
UGI HVAC Enterprises				0
UGI International China. Inc				0
UGI International (Romania)				0
UGI LNG				0
UGI Penn HVAC Services				0
UGI Petroleum Products of DE				0
UGI Romania, Inc.				0
UGID Holding Company				0
Total Tax Loss	(155,074)	290,276		135,202

Explanations of Adjustments:

(1) Equity pick-up from AmeriGas partnership includes amortization of step-up from acquisition. Acquisition was in August 2019. Amortization of step up runs 39 years (although most falls off after year 9)

(2) This \$8.5 MM is the utilization of a §382 limited NOL that comes into the UGI Corporation consolidated return as the result of the Mountaineer Gas Company acquisition on September 1, 2021.

Tax Loss Entities	Taxable Income 2021	Adjustments		Adjusted Taxable Income	(4) Interest Reallocation		Revised Taxable Income
UGI Corporation	(100,191)	54,553	(1)				
		14,384	(5)				
		29,355	(6)	(1,899)	25,009	(4)	23,110
AmeriGas Inc				0			0
AmeriGas Propane Holdings, Inc.	(136,979)	284,717	(2)	147,738	(25,009)	(4)	122,728
Amerigas Technology Group Inc.				0			0
Ashtola Production Company	(1)			(1)			(1)
Eastfield International Holdings Inc				0			0
EuroGas Holdings Inc.				0			0
Four Flags Drilling Company				0			0
Hellertown Pipeline				0			0
Homestead Holding	(76)			(76)			(76)
Mountaineer Gas Company	(4,891)	4,891	(3)	0			0
Mountaintop Energy Holding Inc				0			0
Newberry Holding				0			0
UGI Asset Management				0			0
UGI Black Sea Enterprises				0			0
UGI Development Company	(4,031)			(4,031)			(4,031)
UGID Holding Company	(8)			(8)			(8)
UGI Energy Ventures, Inc.				0			0
UGI Ethanol Development Company				0			0
UGI Enterprises Inc				0			0
UGI Hunlock Dev				0			0
UGI HVAC Enterprises	(1,556)			(1,556)			(1,556)
UGI International China. Inc				0			0
UGI International (Romania)				0			0
UGI LNG	(3,679)			(3,679)			(3,679)
UGI Penn HVAC Services				0			0
UGI Petroleum Products of DE				0			0
UGI Romania, Inc.				0			0
UGID Holding Company				0			0
Total Tax Loss	(251,412)	387,900		136,487	0		136,487

Explanations of Adjustments:

(1) One time bonus depreciation deduction on non-utility fixed assets for a one-time acquisition.
(2) Equity pick-up from AmeriGas partnership includes amortization of step-up from acquisition (a one time event in August 2019).
(3) Mountaineer Gas Company acquired 9/1/2021. Loss is due to only month of activity in September which is a loss month.

(4) Interest Exp on UGI Corp debt related to the Amerigas buyout reallocated to Amerigas.

25,009	Total Interest Exp on Corp
147,738	Amerigas TI Available

(5) Bonus Depr taken to drive NOL carryback. Normally not taken in a loss year.

(6) Back out UGI International loss since foreign earnings not included.

UGI GAS STATEMENT NO. 8

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Sherry A. Epler

Topics Addressed: **Test Year Sales and Revenues**
Tariff Changes

Dated: January 27, 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed as Senior Manager, Tariff & Supplier Administration, by UGI Utilities, Inc. ("UGI"). UGI has both a Gas Division ("UGI Gas"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Gas?

A. My current responsibilities related to UGI Gas include: (1) all aspects of tariff and rate administration for UGI Gas, including interactions with natural gas suppliers under UGI Gas's supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background.

A. Please see my resume, UGI Gas Exhibit SAE-1, which is attached to my testimony.

Q. Please provide your professional experience.

A. I have worked for UGI since 1986, supporting the Accounting and Rates groups in varying capacities. Please see my resume, UGI Gas Exhibit SAE-1, for my full employment history.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2024 ("HTY"), future test year ending September 30, 2025 ("FTY"), and fully projected future test year ending September 30, 2026 ("FPFTY"); and (2) certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness John D. Taylor, who is employed as Managing Partner by Atrium Economics, LLC (UGI Gas Statement No. 10), is sponsoring allocation of revenue increase and rate design, in addition to his testimony supporting class cost of service, using the projected sales and revenue figures discussed in my testimony.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit SAE-1 (Resume), UGI Gas Exhibit SAE-2 (15 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3 (Normalized Multi-Year and Normalized 12-Month Ending Trends of Use Per Customer for Residential and Commercial Heating), UGI Gas Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-7 (Fully Projected Future Test Year, Future Test Year, and Historic Test Year Usage Per Customer Detail by Class), UGI Gas Exhibit SAE-8 (No Notice Service ("NNS") Rate Calculation), UGI Gas Exhibit SAE-9 (Monthly Balancing Service ("MBS") Rate Calculation), UGI Gas Exhibit SAE-10 (Rider D-Merchant Function Charge ("MFC") Calculation), certain portions of UGI Gas Exhibit F

(Proposed Tariff), and UGI Gas Exhibit E (Proof of Revenue). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEAR SALES AND REVENUE

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by incorporating annualizing and normalizing adjustments to the Company's 2026 fiscal year sales and revenue budgets in order to reflect end of FPFTY conditions for ratemaking purposes. The development of the initial sales and revenue budgets which were utilized as the starting point prior to adjustments is described in the testimony of Vivian K. Ressler (UGI Gas Statement No. 3). Where similar adjustments are made across rate class groups, the methodology applied to develop normalized use per customer adjustments (for the FPFTY, FTY, and HTY) to budget values is the same for all three periods in order to present sales and revenue on a comparable ratemaking basis. A summary of projected use per customer by class group for the FPFTY, FTY, and HTY is included in UGI Gas Exhibit SAE-7. The projected Residential Heating use per customer was established for Rate R/RT-Heating per the UGI Gas model detailed in SDR-RR-11. Since, over time, switching occurs on a regular basis between residential Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." Weather normalized sales for Rate RT-Heating customers for the 12 months ended September 30, 2024, were then utilized to mathematically derive the separate Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per customer regression value).

Actual sales were normalized for Rate R-Non-Heating and Rate RT-Non-Heating, in total, for the 12-month period ended September 30, 2024, to eliminate potential switching impacts that could distort use per customer analyses. These data were used to project combined Rate R/RT-Non-Heating use per customer in total. Weather normalized sales for Rate RT-Non-Heating customers for the 12 months ended September 30, 2024, were then utilized to mathematically derive the separate Rate R-Non-Heating customer values (from the combined Rate R/RT-Non-Heating use per customer value).

The projected Commercial Heating use per customer was established on a combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression techniques detailed in SDR-RR-11. Given that, over time, switching occurs on a regular basis between Rates N (retail service), NT (transportation service) and DS (transportation service), the regression analysis was performed on a total Rates N/NT/DS basis to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." To separate the combined Rate N/NT/DS-Commercial Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Heating use per customer was established on the basis of weather normalized sales for Rate NT-Commercial Heating customers, for the 12 months ended September 30, 2024, as this class is much smaller in number than the Rate N-Commercial Heating class. Rate DS-Commercial Heating use per customer was then established based on budgeted 2026 sales for Rate DS-Commercial Heating, as Rate DS budgeting was performed on a detailed per-customer level. These Rate NT and Rate DS

Commercial Heating values were then utilized to mathematically derive the Rate N-Commercial Heating use per customer values (from the combined Rates N/NT/DS-Commercial Heating use per customer value).

Actual sales were normalized for Rate N-Commercial Non-Heating, Rate NT-Commercial Non-Heating and Rate DS-Commercial Non-Heating, in total, to reflect the 12 months ended September 30, 2024, in order to project combined Rates N/NT/DS-Commercial Non-Heating use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined Rate N/NT/DS-Commercial Non-Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Non-Heating was based on weather normalized sales for Rate NT-Commercial Non-Heating, for the 12 months ended September 30, 2024, and Rate DS-Commercial Non-Heating was based on budgeted 2026 sales for Rate DS-Commercial Non-Heating, which were done on a per-customer level. These Rate NT and Rate DS values were then utilized to mathematically derive the Rate N-Commercial Non-Heating use per customer values (from the combined Rates N/NT/DS-Commercial Non-Heating use per customer value).

Actual sales were normalized for Rate N-Industrial, Rate NT-Industrial, and Rate DS-Industrial to reflect the 12 months ended September 30, 2024, in order to project combined Rates N/NT/DS-Industrial use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined Rate N/NT/DS-Industrial value into respective Rate N, Rate NT and Rate DS values, Rate NT-Industrial was based on weather normalized sales for Rate NT-Industrial for the 12 months ended September 30, 2024. Rate DS-Industrial was based on budgeted 2026 sales for Rate DS-Industrial, which were done on a per-customer level. These Rate NT and Rate

DS values were then utilized to mathematically derive the Rate N-Industrial use per customer value (from the combined Rates N/NT/DS-Industrial use per customer value).

Q. How was temperature accounted for in developing sales and revenue forecasts?

A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree days of 5,568. This annual normal heating degree day calculation is derived from a composite sales weighted value (by system demand) for each of the Company's four delivery regions, and the respective normal heating degree values. Normal heating degree days are defined based upon an average over a 15-year period and are updated every five years; the most recent update was for the 15-year period ending December 31, 2019. UGI Gas Exhibit SAE-2 provides supporting detail by year for the 15-year normal heating degree days.

Q. Is the use of average temperature data for a 15-year period consistent with the methodology used for calculating normal heating degree days in previous UGI Gas base rate cases?

A. Yes. The Company has consistently used a 15-year period methodology in the past eight gas base rate cases that the Company or its former subsidiaries have filed (as listed below).

- UGI Central Penn Gas ("CPG") 2009 Base Rate Case, Docket No. R-2008-2079675
- UGI Penn Natural Gas ("PNG") 2009 Base Rate Case, Docket No. R-2008-2079660
- UGI CPG 2011 Base Rate Case, Docket No. R-2010-2214415
- UGI Gas 2016 Base Rate Case, Docket No. R-2015-2518438
- UGI PNG 2017 Base Rate Case, Docket No. R-2016-2580030
- UGI Gas 2019 Base Rate Case, Docket No. R-2018-3006814
- UGI Gas 2020 Base Rate Case, Docket No. R-2019-3015162
- UGI Gas 2022 Base Rate Case, Docket No. R-2022-3030218

Q. Please describe the adjustments made to the budget for the 12 months ending September 30, 2026, to develop FPFTY sales and revenues.

A. A summary of all adjustments made to the 2026 budget in order to develop FPFTY sales and revenue is shown on UGI Gas Exhibit SAE-4(a). Detail for each of these adjustments is provided on subsequent worksheets labeled 4(b) through 4(l). In total, these adjustments reflect an increase to sales of 30 MMcf and an increase to revenue of $17.488 million, inclusive of Purchased Gas Cost ("PGC") revenues.

Q. Please explain the "Adjustment for Customer/Contract Changes" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Customer/Contract Changes" annualizes customer counts to anticipated end-of-test-year levels based on the Company's most recent forecast for the FPFTY; it is inclusive of any large transportation contract customer changes related to customers served under Rates LFD, XD, and IS. In particular, among other adjustments, this adjustment includes a net decrease of 3,815 Residential Heating customers (Rate R) from budgeted levels to anticipated end-of-test-year levels and a net decrease of 1,497 Commercial Heating customers (Rate N) from budgeted levels to anticipated end-of-FPFTY levels on September 30, 2026.

Q. How were these adjustments calculated?

A. UGI Gas Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments for the stated customer counts. In total, these adjustments decrease sales by 895 MMcf and decrease projected revenues by $10.563 million, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit SAE-4(b) can be found on

UGI Gas Exhibit SAE-4(b)(1), which provides a breakout of customer data for large transportation customer classes.

Q. Please explain the adjustment titled "Adjustment for Customer/Contract Changes – Large Transport and Interruptible Detail" as shown on UGI Gas Exhibit SAE-4(b)(1).

A. The adjustments for large transportation customers were developed by UGI Gas's marketing personnel following their review of individual large customer accounts and market segments. The adjustments reflect annualizing anticipated increases or reductions from original individual customer budgeted sales and revenues. There were no adjustments to the original budget for the Large Transport and Interruptible customers.

Q. Please explain your next adjustment, "Adjustment for Normalized & Annualized Use/Customer" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Normalized & Annualized Use/Customer" normalizes and annualizes usage per customer to projected end-of-test-year levels. Specifically, in developing usage per customer projections for the Company's core Residential Heating rate groups (Rates R and RT), the Company utilized an econometric regression model that incorporates four independent variables: (1) use per customer; (2) heating degree days; (3) lagged heating degree days; and (4) weighted time trend. While use per customer, heating degree days, and lagged heating degree days capture weather related usage factors, which can then be used to project normalized and annualized customer usage under normal weather conditions, the weighted time trend variable of this regression captures non-weather trends that underlie changes in usage per customer over time (*e.g.*, conservation). These trends can vary, but as a comprehensive variable, "trend" will capture the impacts of conservation, including but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying, and tracking all variables over time, a trend variable is used to provide a comprehensive indicator of usage trends, which can then be used to forecast for a future period. Additionally, the trend variable is weighted by heating degree days to reflect a "weighted trend," which more accurately reflects that the trends' impacts are directly related to usage during heating time periods.

For the Residential Heating groups of Rates R and RT, the multi-year period regression methodology is the same base method that the Company has utilized in prior rate cases, updated for the use of a common data set period of October 2003 through September 2024. October 2003 is the earliest common data set available for the entire service territory, given the timing and data availability of historic service and former rate district level details for UGI Gas and its former subsidiaries, UGI PNG and UGI CPG.

For the Company's core Commercial Heating rate groups (inclusive of Rates N, NT, and DS), the Company utilized the same regression method as presented in UGI Gas's 2019, 2020, and 2022 Gas Rate Cases. Specifically, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per customer; (2) heating degree days; and (3) lagged heating degree days. For the Commercial Heating group, the Company used the period of October 2012 through September 2024 for regression modeling, or the period during which common non-residential rate structures existed for UGI Gas and its former subsidiaries.

The forecasts for end-of-FPFTY use per customer are generated using the regression results along with a projection of regression variable inputs, including normal annual heating degree days and, where applicable, a weighted trend variable. The results are presented in summary on UGI Gas Exhibit SAE-4(a) and in detail on UGI Gas Exhibit SAE-4(c). In total, the result is a net sales increase, from the fiscal 2026 budget, of 1,165 MMcf, and a net revenue increase, from the fiscal 2026 budget, of $11.683 million, inclusive of PGC revenues.

Q. Why did UGI Gas utilize a multi-year regression period?

A. The Company decided to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends. Consequently, the multi-year regression period more accurately projects usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last eight base rate cases of UGI Gas and its predecessor entities.

Q. Has UGI Gas compared the results of the multi-year regression method to develop normalized usage for Residential Heating and Commercial Heating customer groups with any other normalization method?

A. Yes. Please see UGI Gas Exhibits SAE-3(a) and SAE-3(b), which contain use per customer graphs that illustrate the results of both the multi-year normalized regression method I have explained above ("Normalized Multi-year") and a short-term normalized

("Normalized 12 Months ended") value for the same groups of Residential Heating and Commercial Heating customers. The short-term normalized values are computed via a simple determination of temperature sensitive load each month during the 12 month period ending September 30, 2024. As can be seen from these graphs, short-term trend fluctuations of the "Normalized 12 months ended" line occur in certain periods, but consistently revert to the long-term "Normalized Multi-year" trend which has been used to forecast FPFTY use per customer values, thus capturing the ongoing base trend in declining use per customer.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit SAE-4(a) annualizes FPFTY PGC revenues using the PGC rate in effect as of December 1, 2024. UGI Gas Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment increases PGC revenues for the FPFTY by $11.515 million.

Q. Please explain the following three adjustments shown in summary on UGI Gas Exhibit SAE-4(a): "Adjustment for MFC," "Adjustment for USP," and "Adjustment for GPC."

A. The "Adjustment for MFC" annualizes the Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rates in effect as of December 1, 2024. The MFC Adjustment increases projected revenues by $0.201 million.

The "Adjustment for USP" annualizes the Company's Universal Service Program ("USP") surcharge revenues for the FPFTY based on the USP Rider rate in effect as of December 1, 2024. The Adjustment for USP also updates the sales volume for Customer

Assistance Program ("CAP") customers in the USP Revenue calculation with end of Fiscal Year 2024 data in comparison to the budgeted sales volume for CAP customers, which was calculated using end of Fiscal Year 2023 data. The USP adjustment increases revenues by $4.790 million.

The "Adjustment for GPC" annualizes the Gas Procurement Cost ("GPC") revenues to reflect the impact of all volume adjustments to the original Fiscal Year 2026 planned budget. The GPC adjustment decreases revenues by $0.040 million. Additional details for these three adjustments are provided in UGI Gas Exhibit SAE-4(e), UGI Gas Exhibit SAE-4(f), and UGI Gas Exhibit SAE-4(g), respectively.

Q. Please explain "Adjustment for Excess Take Revenues" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Excess Take" detailed in UGI Gas Exhibit SAE-4(h) reflects the assumption that large transportation customers will evaluate new service elections and will make the necessary adjustments to avoid Excess Take penalties in the FPFTY. The Excess Take adjustment reduces revenue by $1.7 million.

Q. Please explain "Adjustment for STAS" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for STAS" detailed in UGI Gas Exhibit SAE-4(i) annualizes the revenue for the State Tax Adjustment Surcharge ("STAS") for the FPFTY based on the STAS Rider rate in effect as of December 1, 2024. This adjustment increases revenues by $0.082 million.

Q. Please explain the "Adjustment for EEC Rider" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Rider" annualizes the revenue from the Energy Efficiency and Conservation ("EE&C") Rider ("EEC Rider") for the FPFTY based on the EEC Rider rate in effect as of December 1, 2024. This adjustment decreases revenues by $0.024 million and is shown on UGI Exhibit SAE-4(j).

Q. Please explain the "Adjustment for EEC Conservation Impact" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Conservation Impact" annualizes the impact to revenues from UGI Gas's ongoing EE&C programs and associated reduced energy consumption as a result of measures implemented as part of the EE&C programs. This adjustment decreases FPFTY sales by 240 MMcf and decreases revenues by $2.564 million and can be seen on UGI Gas Exhibit SAE-4(k).

Q. Please explain the "Adjustment for DSIC" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for DSIC**"** annualizes Distribution System Improvement Charge ("DSIC") revenue based on the application of the 5% DSIC charge cap to FPFTY revenues. The FPFTY budget utilized a rate of 4.46%. This adjustment applies a 5% DSIC rate in order to annualize the DSIC to end of FPFTY conditions. The 5% rate is currently projected to be effective at the end of the FTY, and that 5% capped rate will remain in place through the FPFTY period. This allows the Company to properly quantify DSIC revenues, which will be rolled into the new base rates established in this proceeding as a result of re-setting the DSIC rate to zero pursuant to 66 Pa. C.S. § 1358(b)(1). This adjustment increases revenues by $4.107 million and is shown on UGI Gas Exhibit SAE-4(l).

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and non-jurisdictional revenue?

A. Yes. Pursuant to the terms of the Revenue Sharing Incentive Mechanism in Section 11 of the UGI Gas tariff, these revenues are appropriately treated as below the line for ratemaking purposes and, thus, have been excluded.

III. DEVELOPMENT OF SALES AND REVENUE FOR THE FTY AND HTY

Q. How were normalized and annualized sales and revenue determined for the FTY?

A. Budgeted sales and revenues serve as the starting point for developing the normalized and annualized FTY sales and revenues, as shown in UGI Gas Exhibit SAE-5. All of the adjustments that were made in the development of the FPFTY sales and revenues were also made in the development of the FTY sales and revenues, with the exception of the adjustments for the EEC Conservation Impact that are contained in the FPFTY but not the FTY.

Q. How were normalized and annualized sales and revenue determined for the HTY?

A. Historic sales and revenues serve as the starting point for developing the normalized and annualized HTY sales and revenues shown in UGI Gas Exhibit SAE-6. All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, with the exception of the adjustments for the Weather Normalization Adjustment (“WNA”), EEC Conservation Impact, Gas Delivery

Enhancement ("GDE") Rider, and DSIC. The "Adjustment for WNA" in the HTY removes the revenues associated with the actual WNA revenue recorded in the HTY revenues and margins in order to not double count certain weather-related impacts, as the Adjustment for Normalized & Annualized Use/Customer fully incorporates weather related usage impacts. The EEC Conservation Impact is not required, as the actual HTY sales and revenue reflect such impacts. The "Adjustment for GDE" in the HTY annualizes GDE Rider revenue based on the current rate as of September 1, 2024.

Q. Is the Company proposing any change to the rate assessed under Rate NNS (No Notice Service)?

A. Yes. Rate NNS is a daily balancing service offered by the Company. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make an election under Rate NNS up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The Company is proposing to update the tariffed Rate NNS charge to reflect current cost elements, using the methodology agreed to in the Settlement from the Company's 2019 Gas Rate Case.

Q. How was the proposed Rate NNS charge developed?

A. The Rate NNS charge is a monthly charge established using the Company's cost of interstate storage that can be utilized for balancing excess or shortfall requirements on the Company system. UGI Gas Exhibit SAE-8 shows the calculation of the Rate NNS charge. This charge was developed based on the same methodology used in the Company's 2019

Gas Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate is $0.2040 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity. This compares to a current NNS rate of $0.2200 per Mcf/d of elected NNA, which was established in the Company's 2022 Gas Rate Case (see Paragraph 44 in the Recommended Decision issued on July 28, 2022 at Docket Nos. R-2021-3030218, *et al.*).

Q. Will the Company continue to credit the revenues received from Rate NNS to PGC Rates?

A. Yes, revenues from Rate NNS will continue to be credited to the PGC Rates as part of the Company's annual 1307(f) proceeding.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excess volumes, or receipt of shortfalls, in subsequent months.

Q. Has the Company proposed any changes to the Rate MBS rates?

A. Yes. UGI Gas Exhibit SAE-9 provides the basis for the MBS rate calculation. As a result of the settlement in the Company's 2019 Gas Rate Case, storage demand charges were included in the calculation of Rate MBS on a 100% load factor basis and the Company is continuing that inclusion in the proposed rates presented. The MBS rate is updated annually on December 1st each year, using 12 months of data ending in September, for the average monthly imbalance utilized in development of the rate. The MBS rates most recently updated for December 1, 2024, are: $0.0115/Mcf for Rates DS and IS; $0.0069/Mcf for Rate LFD; and $0.0058/Mcf for Rate XD. As seen on UGI Gas Exhibit SAE-9, the proposed MBS rates will be: $0.0128/Mcf for Rates DS and IS; $0.0074/Mcf for Rate LFD; and $0.0075/Mcf for Rate XD. These Rate MBS increases are principally driven by increases to the average capacity charge.

Q. Will the Company continue to credit the revenues received from Rate MBS to PGC Rates?

A. Yes, revenues from Rate MBS will continue to be credited to the PGC as part of the Company's annual 1307(f) proceeding.

Q. Please describe the GPC.

A. The GPC recovers costs associated with gas procurement that were unbundled from base rates.

Q. Is the Company proposing to update its GPC in this proceeding?

A. No. The Company proposes to continue the $0.0660/Mcf blended rate that was approved in the Company's 2020 Gas Rate Case (see Joint Petition for Approval of Unopposed Settlement of All Issues, Appx. A, p. 12, filed on August 3, 2020, at Docket Nos. R-2019-3015162, *et al.*, which was approved by the Commission's Opinion and Order entered on October 8, 2020, in that proceeding).

Q. Please describe the MFC.

A. The MFC is equal to the fixed percentage of purchased gas costs that are expected to be uncollectible.

Q. Is the Company proposing to update its MFC in this proceeding?

A. Yes. The Company is updating the percentages for the MFC rates to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will be 2.56%, and the MFC for the commercial class will be 0.56%. Please see UGI Gas Exhibit SAE-10 for additional details.

Q. Please describe the USP Rider.

A. The USP Rider recovers those costs associated with the provision of universal service offerings approved by the Commission in the Company's Universal Service and Energy Conservation Plan.

Q. Is the Company proposing any changes to the USP Rider?

A. Yes. The Company is proposing changes to the annual reconciliation provisions of Rider F – Universal Service Program "USP" to update the threshold number of customers enrolled in CAP that is used in the calculation of the offset applied to recoverable CAP costs. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would arguably have occurred if not for CAP. The Company proposes to set the CAP enrollee threshold equal to the number of CAP participants as of September 30, 2025, to provide an enrollee figure that reflects the actual ongoing impacts on CAP enrollment. This proposal is consistent with the establishment of the CAP enrollee figure in the UGI Gas 2020 Rate Case at Docket No. R-2019-3015162.

IV. TARIFF CHANGES

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement number, Notice language, Issue and Effective dates, and page numbers as necessary per this case. Apart from the proposed rate schedule changes, a complete list of tariff modifications can be found in the List of Changes Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 55 to UGI Gas Tariff No. 7 and Proposed Supplement No. 55 to UGI Gas Tariff No. 7S. As discussed in the direct testimony of John D. Taylor, UGI Gas Statement No. 10, the Company is proposing to complete the unification of Rate DS for the former North and South/Central Rate Districts, which is the only distribution rate remaining to be unified since the Commission-approved merger of UGI Central Penn Gas, Inc. and UGI Penn Natural Gas, Inc. into UGI Utilities, Inc.[1] Relatedly, UGI Gas is proposing to fully consolidate the listings of counties served in the Description of Territories Served, which are currently apportioned by the three former Rate Districts. More significant proposed changes to the tariffs include:

- The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset to 0.00%.
- Rider D – MFC has been set to 2.56% for PGC Residential Customers and 0.56% for Non-Residential PGC Customers, as described above.

[1] See Joint Application of UGI Utilities, Inc., UGI PNG and UGI CPG for Certificate of Public Convenience for Merger, Docket Nos. A-2018-30000381, A-2018-30000382 and A-2018-2018-30000383 (Opinion and Order entered Sept. 20, 2018).

- Section 15. Price to Compare ("PTC") has been updated to reflect changes to the MFC.
- Rider F – Universal Service Program has been revised so that the CAP credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2025, in place of the existing September 30, 2022 date.
- Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b)(1).
- Definitions – Added definitions for daily and monthly price publications and replaced references to Gas Daily and Inside FERC. Clarified that the closest applicable alternative price location may be used if reference price locations are unavailable to the Company. This change is intended to address possible changes in index publications whereby the Company will be able to update pricing, if needed, without interruption in tariff application.
- Rule 22 – Replaced references to index with Reference Prices to comport with the added definitions of daily and monthly price publications.
- Unauthorized Overruns – Aligned minimum charge across all rate classes, increasing the charge for Rate LFD and Rate XD customers to $50 from $27.50. Clarified that the Maximum Daily Excess Balancing Charge in Section 22.4 may also be used in the calculation of Unauthorized Overrun pricing.
- Updated residential and commercial purchase of receivables rates due to the change in the MFC.
- Aggregation Agreement Definitions – Clarified the nomination procedure's location on the Energy Management Website and added definitions for Choice Aggregator, Choice Broker, and Choice Natural Gas Supplier.

Q. Is the Company proposing any additional tariff changes?

A. Yes. The Company is proposing two updates to Rate IS. The first revision adds clarifying language which requires manual interruptible ("MI") customers to maintain the ability to transfer the fuel source of its interruptible equipment from natural gas to an alternate fuel manually. Additionally, the second revision is the elimination of tariff-defined take-or-pay minimum annual bill volumes for Rate IS (Automatic Temperature Controlled ("ATC) or MI) customers.

Q. Please describe the revision for the MI customers.

A. In lieu of the existing Off-Peak Period usage requirement of 5,000 MCF for the April through October seasonal period, the Company is proposing an annualized minimum usage requirement to qualify as an MI Rate IS customer. This revision better aligns customer obligations with the Company's application of its right to interrupt non-firm gas service for Rate IS at all times and aligns with the Company's peak day analysis, which assumes MI customers are off the system.

Q. Please describe the revision for the ATC customers.

A. In lieu of the existing annual usage requirement of 500 MCF for ATC customers, minimums will be incorporated in Rate IS service contracts. This revision better aligns customer obligations with the Company's application of its right to interrupt non-firm gas service for Rate IS at all times and aligns with the Company's peak day analysis, which assumes ATC customers are off the system.

Q. Will this update materially impact the MI customers?

A. No, the Company anticipates this will have a negligible impact on its customer base because MI customers are familiar with the nature of their service from the Company, as outlined in the tariff and their interruptible service agreements. Associated per customer minimums will be established and maintained on a per customers basis going forward.

Q. Please explain the elimination of tariff-defined annual minimum bill volumes for Rate IS customers.

A. The Company has determined that it would be simpler and more efficient to rely on the interruptible service agreements to define any minimal annual bill volumes, which can vary materially in accordance with customer equipment configurations and sizing. Today, the majority of Rate IS customers have a predetermined negotiated minimum annual bill volume in their interruptible service agreements. By removing the annual minimum bill volume from the tariff, UGI Gas will clarify that such minimum annual bill volumes may be subject to negotiation and may vary by customer.

Q. How many Rate IS customers have annual minimum bill values specified in their interruptible service agreements?

A. As of September 2024, the Company had 258 Rate IS customers in Pennsylvania. A majority of this population has a minimum annual bill volume specified in their interruptible service agreements with the Company. Upon contract renewals, related minimum bill amounts will be incorporated into contracts for those not already in place.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

<u>Work Experience</u>

<u>UGI Utilities, Inc., Denver, PA</u>

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

<u>UGI Utilities, Inc., Reading, PA</u>

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

<u>Education</u>

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

<u>Previous testimony provided before the Pennsylvania Public Utility Commission</u>:

Docket No. R-2021-3023618	UGI Electric Division Base Rate Case
Docket No. R-2021-3030218	UGI Gas Division Base Rate Case
Docket No. R-2022-3037368	UGI Electric Division Base Rate Case

UGI GAS

EXHIBIT SAE-2

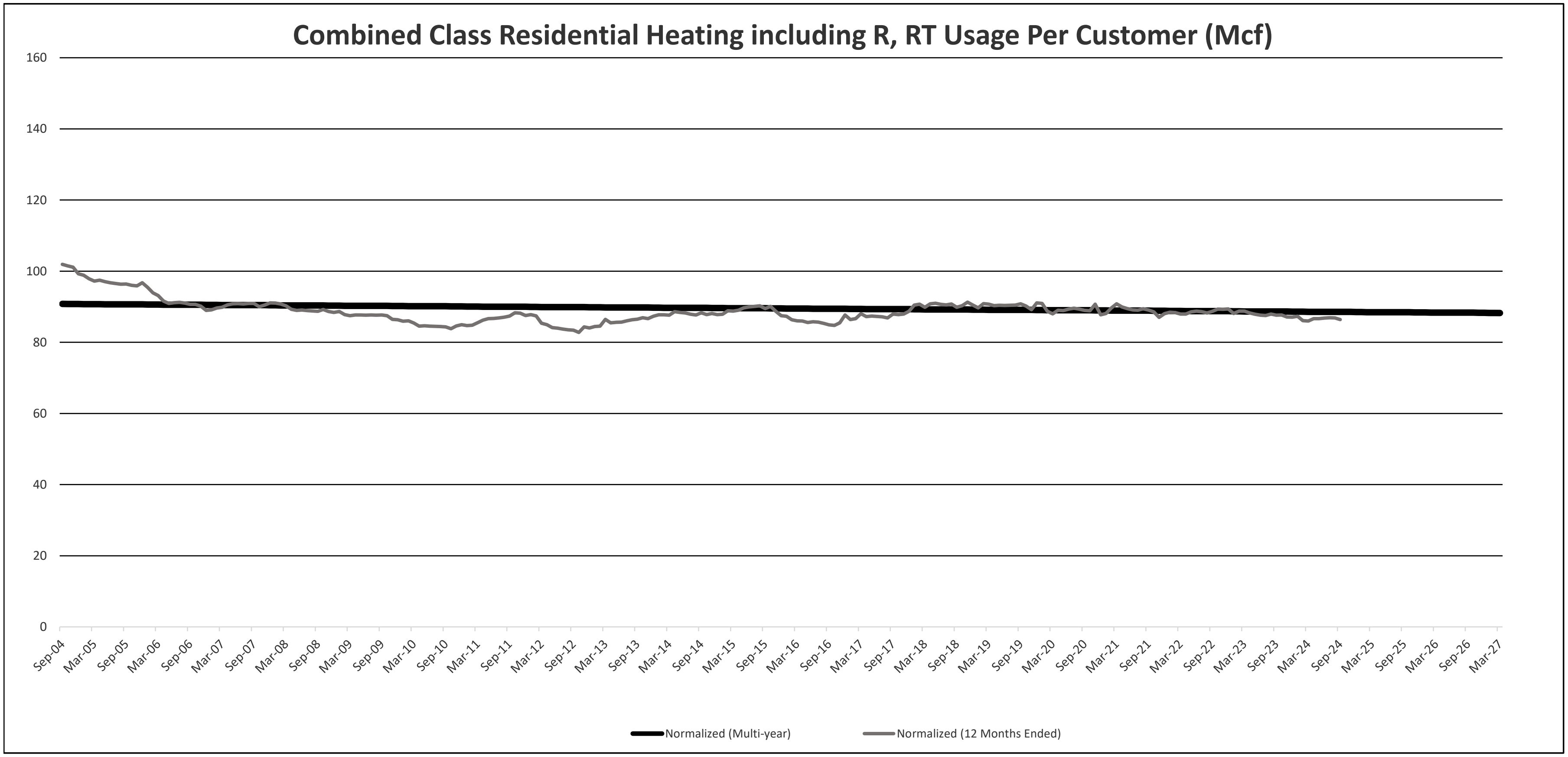
UGI Utilities, Inc. - Gas Divison
15 Year Normal Heating Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average *
Jan	1,195	891	996	1,053	1,292	1,154	1,251	999	1,042	1,313	1,236	1,132	956	1,150	1,140	1,120
Feb	943	953	1,178	977	931	1,018	947	813	975	1,114	1,282	915	714	769	900	962
Mar	950	774	816	823	777	627	834	484	882	974	961	578	865	904	826	805
Apr	391	391	550	373	425	327	414	431	424	464	409	464	261	567	318	414
May	282	198	144	279	180	154	126	70	175	153	88	221	206	62	119	164
Jun	21	46	27	26	43	25	20	37	21	15	36	24	32	30	27	30
Jul	4	4	20	7	20	5	1	1	5	14	6	3	3	3	1	0
Aug	5	11	24	23	19	9	11	8	15	16	11	2	20	2	7	16
Sep	47	129	79	85	116	68	75	110	140	100	47	53	90	58	34	83
Oct	357	431	227	467	436	383	399	336	330	305	385	319	230	365	272	350
Nov	613	555	741	724	569	670	559	782	774	764	516	586	687	771	769	672
Dec	1,121	814	1,008	1,016	1,052	1,162	841	844	1,009	916	631	974	1,086	883	926	952
Totals	5,929	5,197	5,810	5,853	5,860	5,602	5,478	4,915	5,792	6,148	5,608	5,271	5,150	5,564	5,339	5,568

*Average adjusted for rounding of 15 year calculation and normal representation of Heating Degree Days falling consecutively through normal year.

UGI GAS

EXHIBIT SAE-3(a) – (b)



Combined Class Residential Heating including R, RT Usage Per Customer (Mcf)
160
140
120
100
80
60
40
20
0
Sep-04
Mar-05
Sep-05
Mar-06
Sep-06
Mar-07
Sep-07
Mar-08
Sep-08
Mar-09
Sep-09
Mar-10
Sep-10
Mar-11
Sep-11
Mar-12
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Sep-21
Mar-22
Sep-22
Mar-23
Sep-23
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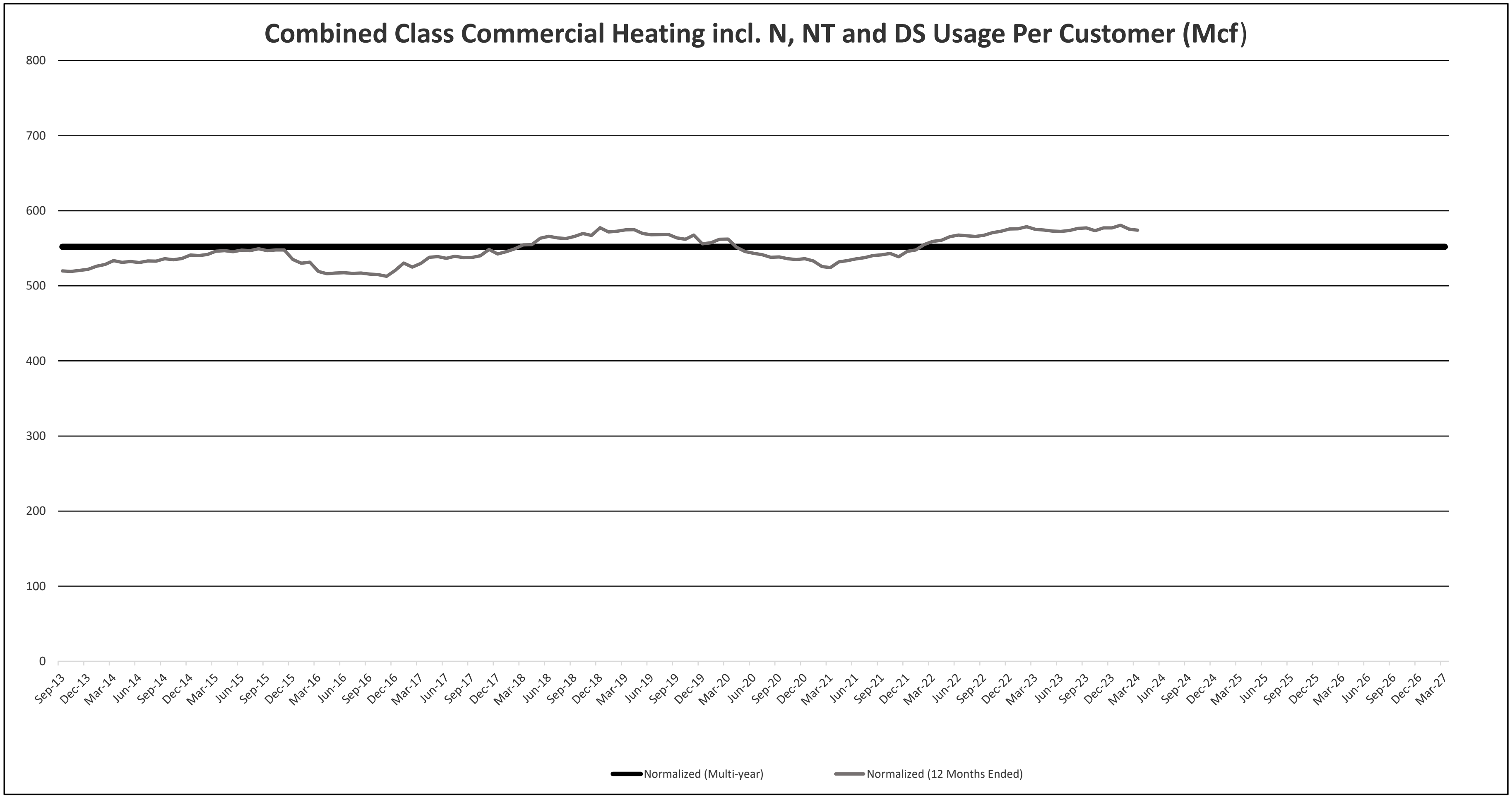
Mar-25
Sep-25
Mar-26
Sep-26
Mar-27
Normalized (Multi-year)
Normalized (12 Months Ended)



Combined Class Commercial Heating incl. N, NT and DS Usage Per Customer (Mcf)
800
700
600
500
400
300
200
100
0
Sep-13 Dec-13 Mar-14 Jun-14 Sep-14 Dec-14 Mar-15 Jun-15 Sep-15 Dec-15 Mar-16 Jun-16 Sep-16 Dec-16 Mar-17 Jun-17 Sep-17 Dec-17 Mar-18 Jun-18 Sep-18 Dec-18 Mar-19 Jun-19 Sep-19 Dec-19 Mar-20 Jun-20 Sep-20 Dec-20 Mar-21 Jun-21 Sep-21 Dec-21 Mar-22 Jun-22 Sep-22 Dec-22 Mar-23 Jun-23 Sep-23 Dec-23 Mar-24 Jun-24 Sep-24 Dec-24 Mar-25 Jun-25 Sep-25 Dec-25 Mar-26 Jun-26 Sep-26 Dec-26 Mar-27
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-4(a) – (l)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2026 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2026	344,714	1,108,563	723,506	
Adjustment for Customer/Contract Changes	(895)	(10,563)	(5,447)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	1,165	11,683	7,713	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		11,515	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		201	201	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		4,790	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(40)	(40)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(h)
Adjustment for STAS		82	82	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Rider		(24)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for EEC Conservation Impact	(240)	(2,564)	(1,277)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for DSIC		4,107	4,107	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Fully Projected Future Test Year 2026	344,744	1,126,050	727,146	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FPFTY Revenues (Unadjusted)	$ 7,433	$ 632,170	$ 55,406	$ 8,246	$ 175,058	$ 8,140	$ 67,290	$ 35,092	$ 119,727	$ 1,108,563
2	FPFTY PGC Revenues	$ (1,911)	$ (277,218)	$ (4,404)	$ (4,143)	$ (91,223)	$ (4,541)	$ (412)	(929)	(277)	(385,057)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 5,522	$ 354,952	$ 51,002	$ 4,103	$ 83,835	$ 3,599	$ 66,878	$ 34,163	$ 119,450	$ 723,506
4	FPFTY Average Effective Customers (Unadjusted)	20,046	530,780	81,425	2,945	46,215	609	21,251	1,330	1,002	705,603
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 0.275	$ 0.669	$ 0.626	$ 1.393	$ 1.814	$ 5.910	$ 3.147	$ 25.686	$ 119.212	$ 1.025
6	FPFTY Customers (Fully Adjusted)	19,875	526,965	81,425	2,905	44,718	596	21,251	1,330	1,002	700,067
7	Change in Customers during FPFTY (L6 - L4)	(171)	(3,815)	-	(40)	(1,497)	(13)	-	-	-	(5,536)
8	Annualization of Margin (L5 * L7)	$ (47)	$ (2,551)	$ -	$ (56)	$ (2,716)	$ (77)	$ -	$ -	$ -	$ (5,447)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.371	$ 1.191	$ 0.680	$ 2.800	$ 3.788	$ 13.366	$ 3.166	$ 26.385	$ 119.488	$ 1.571
10	Annualization of Total FPFTY Revenue (L7 * L9)	$ (63)	$ (4,544)	$ -	$ (112)	$ (5,671)	$ (174)	$ -	$ -	$ -	$ (10,563)
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	$ (16)	$ (1,993)	$ -	$ (56)	$ (2,955)	$ (97)	$ -	$ -	$ -	$ (5,117)
12	Total FPFTY UPC (Unadjusted) - MCF	15.60	85.60	80.80	256.80	359.50	1,360.20	700.30	6,763.20		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(3)	(327)	-	(10)	(538)	(18)	-	-	-	(895)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-4(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FPFTY Revenues (Unadjusted)	$ 56,288	$ 39,074	$ 2,395	$ 21,970	$ 119,727
2	FPFTY PGC Revenues	(277)	-	-	-	(277)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 56,012	$ 39,074	$ 2,395	$ 21,970	$ 119,450
4	FPFTY Average Effective Customers (Unadjusted)	631	55	58	258	1,002
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 88.767	$ 710.438	$ 41.286	$ 85.154	$ 119.212
6	FPFTY Customers (Fully Adjusted)	631	55	58	258	1,002
7	Change in Customers during FPFTY (L6 - L4)	-	-	-	-	-
8	Annualization of Margin	$ -	$ -	$ -	$ -	$ -
9	Average Annual Revenue Per Customer (L1 / L4)	$ 89.205	$ 710.438	$ 41.286	$ 85.154	$ 119.488
10	Annualization of Total FPFTY Revenue	$ -	$ -	$ -	$ -	$ -
11	Annualization of FPFTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FPFTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FPFTY Sales - MMCF	-	-	-	-	-

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Reconciliation Adj. *	[11] Total
1	FPFTY (Unadjusted) Use/Customer ("UPC") - MCF	15.60	85.60	80.80	256.80	359.50	1,360.20	700.30	6,763.20			
2	FPFTY UPC (Fully Adjusted) - MCF	16.30	88.70	81.90	249.70	340.20	905.40	727.70	6,763.20			
3	Change in UPC - MCF (L2 - L1)	0.70	3.10	1.10	(7.10)	(19.30)	(454.80)	27.40	0.00			
4	FPFTY Customers (Fully Adjusted)	19,875	526,965	81,425	2,905	44,718	596	21,251	1,330	1,002	-	700,067
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	14	1,634	90	(21)	(863)	(271)	582	-	-	-	1,165
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 167	$ 19,592	$ 558	$ (201)	$ (8,390)	$ (2,635)	$ 2,368	$ -		$ 224	$ 11,683
7	Total Unit Revenue Adjustment (L6 / L5)	$ 11.9932	$ 11.9932	$ 6.2309	$ 9.7217	$ 9.7217	$ 9.7217	$ 4.0676	$ -	$ -		
8	Distribution Margin Adjustment (L5 * L9)	$ 72	$ 8,456	$ 464	$ (79)	$ (3,312)	$ (1,040)	$ 2,235	$ -			$ 6,795
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.1755	$ -		
10	PGC Revenue (L5 * L11)	$ 78	$ 9,194	$ -	$ (116)	$ (4,857)	$ (1,526)	$ -	$ -		$ (99)	$ 2,675
11	PGC Unit Rate	$ 5.6281	$ 5.6281		$ 5.6281	$ 5.6281	$ 5.6281					
12	EE&C Revenue Adjustment (L5 * L13)	$ 3	$ 295	$ 16	$ (1)	$ (31)	$ (10)	$ 21	$ -			$ 293
13	EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0888	$ -		
14	USP Revenue Adjustment (L5 * L15)	$ 8	$ 943	$ 52	$ -	$ -	$ -	$ -	$ -	$ -		$ 1,002
15	USP Unit Rate	$ 0.5770	$ 0.5770	$ 0.5770	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 2	$ 209		$ (1)	$ (21)	$ (7)					$ 182
17	MFC Unit Rate	$ 0.1278	$ 0.1278		$ 0.0248	$ 0.0248	$ 0.0248					
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 4	$ 495	$ 27	$ (4)	$ (168)	$ (53)	$ 113	$ -			$ 414
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500			
20	Total Margin Adjustment (L8 + L16 + L18)	$ 78	$ 9,160	$ 490	$ (84)	$ (3,502)	$ (1,100)	$ 2,347	$ -		$ 322	$ 7,713
21	Total Unit Margin Adjustment (L20 / L5)	$ 5.6073	$ 5.6073	$ 5.4731	$ 4.0575	$ 4.0575	$ 4.0575	$ 4.0315	$ -	$ -		

Notes:

* Column (10) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for PGC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FPFTY	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FPFTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes	3,322	7,176	10,059	13,158	10,510	8,674	4,429	2,129	1,143	984	1,015	1,446	64,044
PGC Revenue Adjustment	$597	$1,290	$1,809	$2,366	$1,890	$1,560	$796	$383	$206	$177	$182	$260	$11,515

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for MFC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FPFTY	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FPFTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes-Rate R	2,390	5,164	7,207	9,399	7,525	6,230	3,186	1,517	791	673	697	1,019	
Total PGC Volumes-Rate N	933	2,011	2,851	3,759	2,984	2,443	1,243	611	352	310	318	428	
Total PGC Volumes	3,322	7,176	10,059	13,158	10,510	8,674	4,429	2,129	1,143	984	1,015	1,446	64,044
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	
MFC Rate N Adj Rate	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
Rate R Revenue Variance	$10	$21	$29	$38	$31	$25	$13	$6	$3	$3	$3	$4	
Rate N Revenue Variance	$1	$2	$2	$3	$2	$2	$1	$0	$0	$0	$0	$0	
Total Revenue Variance	$10	$23	$32	$41	$33	$27	$14	$7	$4	$3	$3	$4	$201

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for USP

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original FPFTY Budget USP Calculation	$1,226	$2,651	$3,702	$4,831	$3,864	$3,196	$1,632	$778	$408	$349	$361	$524	$23,521
Corrected FPFTY Budget USP Calculation	$1,200	$2,595	$3,624	$4,730	$3,782	$3,128	$1,598	$762	$400	$341	$353	$513	$23,027
Variance to Original FPFTY Budget Calculation	($26)	($56)	($78)	($101)	($81)	($67)	($34)	($16)	($9)	($7)	($8)	($11)	($494)
Original FPFTY Budget USP Rate	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	
FPFTY USP Rate	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	
USP Rate Variance	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	
Total Rate R Volumes	2,730	5,903	8,243	10,758	8,604	7,117	3,635	1,734	909	776	803	1,168	52,378
Total Rate R excl CAP Volumes	2,557	5,530	7,722	10,079	8,060	6,666	3,405	1,624	852	727	752	1,094	49,067
USP Rate Revenue Variance	$275	$596	$832	$1,085	$868	$718	$367	$175	$92	$78	$81	$118	$5,285
Total Revenue Variance	$250	$540	$754	$984	$787	$651	$332	$159	$83	$71	$73	$107	$4,790

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for GPC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
GPC Rate FPFTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FPFTY Budget	(31)	(65)	(94)	(123)	(98)	(80)	(41)	(21)	(13)	(11)	(12)	(15)	(604)
Revenue Variance	($2)	($4)	($6)	($8)	($6)	($5)	($3)	($1)	($1)	($1)	($1)	($1)	($40)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for STAS

		@ -0.14% Unadjusted 2026 TOTAL		@ -0.13% Adjusted 2026 TOTAL		Revenue Adjustment Total
Residential-Non Htg	$	(10)	$	(10)	$	0
Residential-Heating	$	(886)	$	(858)	$	28
Residential-RT	$	(78)	$	(74)	$	4
Total R/RT	$	(974)	$	(942)	$	33
Commercial-Non Htg	$	(12)	$	(11)	$	1
Commercial- Htg	$	(245)	$	(214)	$	32
Commercial-NT	$	(89)	$	(86)	$	3
Industrial	$	(11)	$	(7)	$	4
Industrial-NT	$	(6)	$	(5)	$	0
Total N/NT	$	(363)	$	(323)	$	40
Total DS	$	(49)	$	(46)	$	3
Total LFD	$	(79)	$	(72)	$	7
Total XD-F	$	-	$	-	$	-
Total Interruptible	$	-	$	-	$	-
Grand Total	$	(1,465)	$	(1,383)	$	82

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for EEC Rider

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget FPFTY R/RT Rate	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
FPFTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
R/RT Rate Variance	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	
R/RT Rate Volumes	2,730	5,903	8,243	10,758	8,604	7,117	3,635	1,734	909	776	803	1,168	52,378
R/RT Revenue Adjustment	($53)	($114)	($159)	($208)	($166)	($137)	($70)	($33)	($18)	($15)	($15)	($23)	($1,011)
Original Budget FPFTY N/NT Rate	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
FPFTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
N/NT Rate Variance	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	
N/NT Rate Volumes	1,790	3,611	5,001	6,505	5,213	4,318	2,304	1,233	787	715	729	921	33,126
N/NT Revenue Adjustment	$15	$30	$42	$55	$44	$36	$19	$10	$7	$6	$6	$8	$278
Original Budget FPFTY DS Rate	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
FPFTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
DS Rate Variance	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	
DS Rate Volumes	476	798	1,241	1,601	1,438	1,197	695	421	298	258	263	311	8,995
DS Revenue Adjustment	($4)	($7)	($11)	($14)	($13)	($11)	($6)	($4)	($3)	($2)	($2)	($3)	($81)
Original Budget FPFTY LFD Rate	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
FPFTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
LFD Rate Variance	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	
LFD Rate Volumes	2,101	2,372	2,662	2,894	2,593	2,490	2,153	1,981	1,831	1,804	1,834	1,875	26,589
LFD Revenue Adjustment	$62	$70	$79	$86	$77	$74	$64	$59	$54	$54	$54	$56	$790
Total Revenue Adjustment	$20	($20)	($49)	($81)	($58)	($38)	$7	$32	$41	$42	$43	$38	($24)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 10/01/2025)

Yearly Gas Savings by Rate Class 2026 - 2041 (Cumulative MMBtus)

Rate Class Description	Fiscal Year 2026	2027	2028	2029	2030	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY26 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	187,035	198,006	206,266	214,128	223,043	205,696	1.034	198,932	604,631	**(0.3)**
Nonresidential (N/NT)	35,354	38,780	41,988	46,016	48,158	42,059	1.034	40,676	65,020	**(0.6)**
Total	**222,389**	**236,786**	**248,254**	**260,144**	**271,201**	**247,755**		**239,608**	**669,651**	

Description	[1] Rate R Residential-Htg	[2] Rate RT Residential Htg-RT	[3] Rate N Commercial-Htg	[4] Rate NT Commercial Htg-NT	[5] Rate N Industrial	[6] Rate NT Industrial -NT	[7] Total
FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	88.7	85.0	340.2	703.3	905.4	2,085.5	
FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	88.4	84.7	339.6	702.7	904.8	2,084.9	
Change in UPC -MCF	(0.3)	(0.3)	(0.6)	(0.6)	(0.6)	(0.6)	
End of Year FPFTY Customers	526,965	77,666	44,718	19,240	596	466	669,651
Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(173)	(26)	(28)	(12)	(0)	(0)	(240)
Total Revenue Adjustment (L10 + L12 + L14 + L22)	$ (2,079)	$ (159)	$ (272)	$ (49)	$ (4)	$ (1)	$ (2,564)
Total Unit Revenue Adjustment (L6 / L5)	11.9932	6.2309	9.7217	4.0676	9.7217	4.0676	10.7021
Distribution Margin Adjustment (L5 * L9)	$ (897)	$ (132)	$ (107)	$ (46)	$ (1)	$ (1)	$ (1,186)
Distribution Unit Rate (Rates N, DS Weighted Value by District)	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	
PGC Revenue (L5 * L11)	$ (976)	$ -	$ (157)	$ -	$ (2)	$ -	$ (1,135)
PGC Unit Rate	$ 5.6281		$ 5.6281		$ 5.6281		
EE&C Revenue Adjustment (L5 * L13)	$ (31)	$ (5)	$ (1)	$ (0)	$ (0)	$ (0)	$ (37)
EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	
USP Revenue Adjustment (L5 * L15)	$ (100)	$ (15)					$ (115)
USP Unit Rate	$ 0.5770	$ 0.5770					
MFC Revenue/Margin Adjustment (L5 * L17)	$ (22)		$ (1)		$ (0)		$ (23)
MFC Unit Rate	$ 0.1278		$ 0.0248		$ 0.0248		
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ (53)	$ (8)	$ (5)	$ (2)	$ (0)	$ (0)	$ (68)
DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	
Total Margin Adjustment (L8 + L16 + L18)	$ (972)	$ (140)	$ (114)	$ (49)	$ (2)	$ (1)	$ (1,277)
Total Unit Margin Adjustment (L20 / L5)	$ 5.6073	$ 5.4731	$ 4.0575	$ 4.0315	$ 4.0575	$ 4.0315	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for DSIC

	@ 4.46% Unadjusted 2026 TOTAL	@ 5% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ 245	$ 278	$ 33
Residential-Heating	$ 16,448	$ 18,937	$ 2,489
Subtotal Residential-Rate R	$ 16,693	$ 19,214	$ 2,522
Residential-RT	$ 2,369	$ 2,704	$ 335
Total Residential	$ 19,062	$ 21,918	$ 2,857
Commercial-Non Htg	$ 177	$ 192	$ 15
Commercial- Htg	$ 3,610	$ 3,754	$ 144
Subtotal Commercial- Rate N	$ 3,786	$ 3,945	$ 159
Commercial-NT	$ 2,700	$ 3,143	$ 443
Commercial-DS	$ 1,219	$ 1,363	$ 144
Commercial-IS	$ 409	$ 459	$ 50
Commericial-XD-F	$ 293	$ 328	$ 35
Commercial-XD-I	$ 30	$ 34	$ 4
Commercial-LFD	$ 925	$ 1,020	$ 94
Total Commercial	$ 9,362	$ 10,292	$ 930
Industrial	$ 155	$ 117	$ (38)
Subtotal Industrial- Rate N	$ 155	$ 117	$ (38)
Industrial-NT	$ 177	$ 199	$ 22
Industrial-DS	$ 279	$ 312	$ 33
Industrial-IS	$ 511	$ 573	$ 62
Industrial-XD-F	$ 698	$ 782	$ 84
Industrial-XD-I	$ 60	$ 68	$ 7
Industrial-LFD	$ 1,475	$ 1,626	$ 151
Total Industrial	$ 3,356	$ 3,677	$ 321
Grand Total	$ 31,779	$ 35,886	$ 4,107

UGI GAS

EXHIBIT SAE-5(a) – (k)

UGI Utilities Inc.- Gas Division
Future Test Year 2025 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2025	344,089	1,094,422	720,427	
Adjustment for Customer/Contract Changes	(685)	(10,355)	(5,232)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	839	8,727	5,840	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		21,079	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		368	368	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		4,787	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(41)	(41)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(h)
Adjustment for STAS		107	107	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for EEC Rider		(28)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for DISC		3,831	3,831	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(k)
Future Test Year 2025	344,243	1,121,199	723,601	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FTY Revenues (Unadjusted)	$ 7,645	$ 620,137	$ 55,581	$ 8,432	$ 172,714	$ 8,401	$ 67,743	$ 35,089	$ 118,679	$ 1,094,422
2	FTY PGC Revenues	$ (1,939)	$ (268,341)	$ (4,423)	$ (4,182)	$ (88,870)	$ (4,624)	$ (415)	(928)	(272)	(373,996)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 5,706	$ 351,796	$ 51,158	$ 4,250	$ 83,845	$ 3,777	$ 67,328	$ 34,161	$ 118,407	$ 720,427
4	FTY Average Effective Customers (Unadjusted)	20,634	524,742	81,425	3,017	46,058	637	21,251	1,329	998	700,091
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 0.277	$ 0.670	$ 0.628	$ 1.409	$ 1.820	$ 5.929	$ 3.168	$ 25.704	$ 118.644	$ 1.029
6	FTY Customers (Fully Adjusted)	20,422	520,755	81,425	2,978	44,547	624	21,251	1,329	1,003	694,334
7	Change in Customers during FTY (L6 - L4)	(212)	(3,987)	-	(39)	(1,511)	(13)	-	-	5	(5,757)
8	Annualization of Margin (L5 * L7)	$ (59)	$ (2,673)	$ -	$ (55)	$ (2,751)	$ (77)	$ -	$ -	$ 382	$ (5,232)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.371	$ 1.182	$ 0.683	$ 2.795	$ 3.750	$ 13.189	$ 3.188	$ 26.403	$ 118.917	$ 1.563
10	Annualization of Total FTY Revenue (L7 * L9)	$ (79)	$ (4,712)	$ -	$ (109)	$ (5,666)	$ (171)	$ -	$ -	$ 382	$ (10,355)
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	$ (20)	$ (2,039)	$ -	$ (54)	$ (2,916)	$ (94)	$ -	$ -	$ -	$ (5,123)
12	Total FTY UPC (Unadjusted) - MCF	15.80	86.00	81.10	260.60	361.10	1,366.30	705.60	6,759.40		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(3)	(343)	-	(10)	(546)	(18)	-	-	235	(685)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-5(b)(1)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FTY Revenues (Unadjusted)	$ 55,640	$ 38,785	$ 2,365	$ 21,889	$ 118,679
2	FTY PGC Revenues	(272)	-	-	-	(272)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 55,367	$ 38,785	$ 2,365	$ 21,889	$ 118,407
4	FTY Average Effective Customers (Unadjusted)	627	55	58	258	998
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 88.305	$ 705.182	$ 40.779	$ 84.842	$ 118.644
6	FTY Customers (Fully Adjusted)	632	55	58	258	1,003
7	Change in Customers during FTY (L6 - L4)	5	-	-	-	5
8	Annualization of Margin	$ 654	$ (175)	$ -	$ (97)	$ 382
9	Average Annual Revenue Per Customer (L1 / L4)	$ 88.739	$ 705.182	$ 40.779	$ 84.842	$ 118.917
10	Annualization of Total FTY Revenue	$ 654	$ (175)	$ -	$ (97)	$ 382
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	380	(113)	-	(32)	235

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	FTY (Unadjusted) Use/Customer ("UPC") - MCF	15.80	86.00	81.10	260.60	361.10	1,366.30	705.60	6,759.40		
2	FTY UPC (Fully Adjusted) - MCF	16.30	88.90	81.90	253.60	339.70	978.40	727.70	6,759.40		
3	Change in UPC - MCF (L2 - L1)	0.50	2.90	0.80	(7.00)	(21.40)	(387.90)	22.10	0.00		
4	FTY Customers (Fully Adjusted)	20,422	520,755	81,425	2,978	44,547	624	21,251	1,329	1,003	694,334
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	10	1,510	65	(21)	(953)	(242)	470	-	-	839
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 122	$ 18,112	$ 406	$ (203)	$ (9,268)	$ (2,353)	$ 1,910	$ -	$ -	$ 8,727
7	Total Unit Revenue Adjustment (L6 / L5)	$ 11.9932	$ 11.9932	$ 6.2309	$ 9.7217	$ 9.7217	$ 9.7217	$ 4.0676	$ -	$ -	
8	Distribution Margin Adjustment (L5 * L9)	$ 53	$ 7,817	$ 337	$ (80)	$ (3,659)	$ (929)	$ 1,802	$ -	$ -	$ 5,342
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.1795	$ -	
10	PGC Revenue (L5 * L11)	$ 57	$ 8,499	$ -	$ (117)	$ (5,365)	$ (1,362)	$ -	$ -	$ -	$ 1,712
11	PGC Unit Rate	$ 5.6281	$ 5.6281		$ 5.6281	$ 5.6281	$ 5.6281				
12	EE&C Revenue Adjustment (L5 * L13)	$ 2	$ 273	$ 12	$ (1)	$ (34)	$ (9)	$ 17	$ -	$ -	$ 260
13	EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0888	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ 6	$ 871	$ 38	$ -	$ -	$ -	$ -	$ -	$ -	$ 915
15	USP Unit Rate	$ 0.5770	$ 0.5770	$ 0.5770	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 1	$ 193		$ (1)	$ (24)	$ (6)				$ 164
17	MFC Unit Rate	$ 0.1278	$ 0.1278		$ 0.0248	$ 0.0248	$ 0.0248				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 3	$ 458	$ 19	$ (4)	$ (186)	$ (47)	$ 91	$ -	$ -	$ 334
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500		
20	Total Margin Adjustment (L8 + L16 + L18)	$ 57	$ 8,468	$ 357	$ (85)	$ (3,868)	$ (982)	$ 1,893	$ -	$ -	$ 5,840
21	Total Unit Margin Adjustment (L20 / L5)	$ 5.6073	$ 5.6073	$ 5.4731	$ 4.0575	$ 4.0575	$ 4.0575	$ 4.0315	$ -	$ -	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for PGC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget PGC Rate FTY	$4.5259	$4.5259	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$1.1022	$1.1022	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes	3,296	7,117	9,978	13,072	10,446	8,626	4,415	2,162	1,185	1,026	1,057	1,436	63,815
PGC Revenue Adjustment	$3,632	$7,845	$1,794	$2,350	$1,878	$1,551	$794	$389	$213	$184	$190	$258	$21,079

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for MFC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget PGC Rate FTY	$4.5259	$4.5259	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$1.1022	$1.1022	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes-Rate R	2,362	5,106	7,128	9,309	7,457	6,176	3,164	1,534	816	699	722	1,007	
Total PGC Volumes-Rate N	933	2,011	2,850	3,763	2,990	2,450	1,250	628	369	327	334	429	
Total PGC Volumes	3,296	7,117	9,978	13,072	10,446	8,626	4,415	2,162	1,185	1,026	1,057	1,436	63,815
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	$0.0250	$0.0250	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	
MFC Rate N Adj Rate	$0.0048	$0.0048	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
Rate R Revenue Variance	$59	$128	$29	$38	$30	$25	$13	$6	$3	$3	$3	$4	
Rate N Revenue Variance	$5	$10	$2	$3	$2	$2	$1	$0	$0	$0	$0	$0	
Total Revenue Variance	$64	$138	$31	$41	$33	$27	$14	$7	$4	$3	$3	$4	$368

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for USP

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original FTY Budget USP Calculation	$1,213	$2,622	$3,663	$4,788	$3,830	$3,169	$1,622	$788	$421	$362	$374	$519	$23,371
Corrected FTY Budget USP Calculation	$1,188	$2,570	$3,589	$4,692	$3,754	$3,106	$1,589	$772	$413	$355	$367	$508	$22,902
Variance to Original FTY Budget Calculation	($24)	($53)	($73)	($96)	($77)	($64)	($33)	($16)	($8)	($7)	($7)	($10)	($468)
Original FTY Budget USP Rate	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	
FTY USP Rate	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	
USP Rate Variance	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	
Total Rate R Volumes	2,703	5,845	8,163	10,670	8,537	7,065	3,615	1,755	939	807	833	1,156	52,089
Total Rate R excl CAP Volumes	2,532	5,476	7,648	9,997	7,998	6,618	3,387	1,645	880	756	781	1,083	48,801
USP Rate Revenue Variance	$273	$590	$824	$1,077	$861	$713	$365	$177	$95	$81	$84	$117	$5,256
Total Revenue Variance	$248	$537	$750	$981	$785	$649	$332	$161	$86	$74	$77	$106	$4,787

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for GPC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
GPC Rate FTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FTY Budget	(31)	(66)	(95)	(126)	(100)	(81)	(42)	(22)	(14)	(12)	(13)	(15)	(616)
Revenue Variance	($2)	($4)	($6)	($8)	($7)	($5)	($3)	($1)	($1)	($1)	($1)	($1)	($41)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for STAS

	@ -0.14% Unadjusted 2025 TOTAL	@ -0.13% Adjusted 2025 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (11)	$ (10)	$ 1
Residential-Heating	$ (869)	$ (810)	$ 60
Residential-RT	$ (78)	$ (73)	$ 5
Total R/RT	$ (958)	$ (893)	$ 65
Commercial-Non Htg	$ (12)	$ (11)	$ 1
Commercial- Htg	$ (242)	$ (225)	$ 17
Commercial-NT	$ (89)	$ (83)	$ 6
Industrial	$ (12)	$ (11)	$ 1
Industrial-NT	$ (6)	$ (5)	$ 0
Total N/NT	$ (361)	$ (336)	$ 25
Total DS	$ (49)	$ (37)	$ 12
Total LFD	$ (78)	$ (73)	$ 5
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (1,446)	$ (1,339)	$ 107

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for EEC Rider

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget FTY R/RT Rate	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
FTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
R/RT Rate Variance	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	
R/RT Rate Volumes	2,703	5,845	8,163	10,670	8,537	7,065	3,615	1,755	939	807	833	1,156	52,089
R/RT Revenue Adjustment	($52)	($113)	($158)	($206)	($165)	($136)	($70)	($34)	($18)	($16)	($16)	($22)	($1,005)
Original Budget FTY N/NT Rate	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
FTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
N/NT Rate Variance	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	
N/NT Rate Volumes	1,790	3,611	5,000	6,517	5,226	4,331	2,319	1,270	823	752	766	922	33,327
N/NT Revenue Adjustment	$15	$30	$42	$55	$44	$36	$19	$11	$7	$6	$6	$8	$280
Original Budget FTY DS Rate	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
FTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
DS Rate Variance	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	
DS Rate Volumes	478	799	1,239	1,599	1,436	1,195	693	419	297	257	261	309	8,984
DS Revenue Adjustment	($4)	($7)	($11)	($14)	($13)	($11)	($6)	($4)	($3)	($2)	($2)	($3)	($81)
Original Budget FTY LFD Rate	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
FTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
LFD Rate Variance	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	
LFD Rate Volumes	2,057	2,320	2,612	2,851	2,553	2,455	2,117	1,945	1,796	1,785	1,829	1,869	26,189
LFD Revenue Adjustment	$61	$69	$78	$85	$76	$73	$63	$58	$53	$53	$54	$56	$778
Total Revenue Adjustment	$20	($21)	($49)	($81)	($58)	($38)	$6	$31	$39	$41	$42	$38	($28)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for DSIC

	@ 4.46% Unadjusted 2025 TOTAL	@ 5% Adjusted 2025 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$253	$284	$31
Residential-Heating	$16,302	$18,276	$1,974
Subtotal Residential-Rate R	$16,555	$18,560	$2,004
Residential-RT	$2,376	$2,664	$288
Total Residential	$18,932	$21,224	$2,292
Commercial-Non Htg	$183	$205	$22
Commercial- Htg	$3,610	$4,047	$437
Subtotal Commercial- Rate N	$3,793	$4,252	$459
Commercial-NT	$2,718	$3,047	$329
Commercial-DS	$1,217	$1,364	$147
Commercial-IS	$412	$462	$50
Commericial-XD-F	$285	$320	$35
Commercial-XD-I	$30	$34	$4
Commercial-LFD	$916	$1,027	$111
Total Commercial	$9,371	$10,506	$1,135
Industrial	$163	$183	$20
Subtotal Industrial- Rate N	$163	$183	$20
Industrial-NT	$178	$200	$22
Industrial-DS	$281	$315	$34
Industrial-IS	$503	$564	$61
Industrial-XD-F	$697	$782	$84
Industrial-XD-I	$59	$66	$7
Industrial-LFD	$1,457	$1,633	$176
Total Industrial	$3,338	$3,743	$404
Grand Total	$31,641	$35,472	$3,831

UGI GAS

EXHIBIT SAE-6(a) – (l)

UGI Utilities Inc.- Gas Division
Historic Test Year 2024 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2024	326,816	1,015,745	703,526	
Adjustment for Customer/Contract Changes	(641)	(5,949)	(4,600)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	11,696	101,563	59,138	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for WNA		(40,911)	(40,911)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for PGC		(16,562)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for MFC		(297)	(297)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for USP		909	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for GPC		522	522	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for Excess Take		(1,615)	(1,615)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for STAS		(15)	(15)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for EEC Rider		127	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(k)
Adjustment for GDE		(3)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(l)
Historic Test Year 2024	337,872	1,053,514	715,748	

UGI Utilities Inc.- Gas Division
Historic Test Year 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	HTY Revenues net of WNA (Unadjusted)	$ 7,816	$ 526,578	$ 51,549	$ 7,258	$ 138,092	$ 6,380	$ 63,154	$ 50,862	$ 123,145	$ 974,834
2	HTY PGC Revenues	$ (1,784)	$ (210,614)	$ (3,711)	$ (3,345)	$ (66,342)	$ (3,332)	$ (391)	(17,239)	(5,462)	(312,219)
3	HTY Revenues net of PGC and WNA - Margin (Unadjusted)	$ 6,032	$ 315,964	$ 47,838	$ 3,913	$ 71,751	$ 3,048	$ 62,763	$ 33,622	$ 117,683	$ 662,614
4	HTY Average Effective Customers (Unadjusted)	21,757	517,734	82,936	3,094	44,682	661	21,337	1,316	987	694,504
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 0.277	$ 0.610	$ 0.577	$ 1.265	$ 1.606	$ 4.611	$ 2.942	$ 25.549	$ 119.233	$ 0.954
6	HTY Customers (Fully Adjusted)	21,199	516,400	79,579	3,088	44,383	667	20,986	1,302	987	688,591
7	Change in Customers during HTY (L6 - L4)	(558)	(1,334)	(3,357)	(6)	(299)	6	(351)	(14)	-	(5,913)
8	Annualization of Margin (L5 * L7)	$ (155)	$ (814)	$ (1,936)	$ (8)	$ (480)	$ 28	$ (1,032)	$ (358)	$ 155	$ (4,600)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.359	$ 1.017	$ 0.622	$ 2.346	$ 3.091	$ 9.652	$ 2.960	$ 38.649	$ 124.767	$ 1.404
10	Annualization of Total HTY Revenue (L7 * L9)	$ (200)	$ (1,357)	$ (2,087)	$ (14)	$ (924)	$ 58	$ (1,039)	$ (541)	$ 155	$ (5,949)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	$ (46)	$ (543)	$ (150)	$ (6)	$ (444)	$ 30	$ (6)	$ (183)	$ -	$ (1,349)
12	Total HTY UPC (Unadjusted) - MCF	14.90	74.60	70.90	217.10	306.60	1,043.20	646.20	6,821.60		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(8)	(100)	(238)	(1)	(92)	6	(227)	(96)	114	(641)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-6(b)(1)

UGI Utilities Inc.- Gas Division
Historic Test Year - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	HTY Revenues (Unadjusted)	$ 58,682	$ 39,899	$ 2,268	$ 22,295	$ 123,145
2	HTY PGC Revenues	(4,205)	(749)	(47)	(462)	(5,462)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 54,477	$ 39,150	$ 2,221	$ 21,834	$ 117,683
4	HFTY Average Effective Customers (Unadjusted)	614	56	58	259	987
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 88.725	$ 699.111	$ 38.301	$ 84.301	$ 119.233
6	HTY Customers (Fully Adjusted)	622	56	58	251	987
7	Change in Customers during FTY (L6 - L4)	8	-	-	(8)	-
8	Annualization of Margin	$ 572	$ (122)	$ 20	$ (315)	$ 155
9	Average Annual Revenue Per Customer (L1 / L4)	$ 95.573	$ 712.489	$ 39.103	$ 86.083	$ 124.767
10	Annualization of Total FTY Revenue	$ 572	$ (122)	$ 20	$ (315)	$ 155
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	304	(171)	(0)	(20)	114

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	HTY (Unadjusted) Use/Customer ("UPC") - MCF	14.90	74.60	70.90	217.10	306.60	1,043.20	646.20	6,821.60		
2	HTY UPC (Fully Adjusted) - MCF	16.30	89.00	81.90	234.10	316.90	1,235.70	727.50	7,598.10		
3	Change in UPC - MCF (L2 - L1)	1.40	14.40	11.00	17.00	10.30	192.50	81.30	776.50		
4	HTY Customers (Fully Adjusted)	21,199	516,400	79,579	3,088	44,383	667	20,986	1,302	987	688,591
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	30	7,436	875	52	457	128	1,706	1,011	-	11,696
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 320	$ 80,101	$ 5,373	$ 452	$ 3,934	$ 1,105	$ 6,925	$ 3,353		$ 101,563
7	Total Unit Revenue Adjustment (L6 / L5)	$ 10.7719	$ 10.7719	$ 6.1381	$ 8.6056	$ 8.6056	$ 8.6056	$ 4.0588	$ 3.3168	$ -	$ 8.6833
8	Distribution Margin Adjustment (L5 * L9)	$ 154	$ 38,493	$ 4,531	$ 201	$ 1,754	$ 493	$ 6,548	$ 3,095		$ 55,269
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.0611	$ -	
10	PGC Revenue (L5 * L11)	$ 134	$ 33,655		$ 238	$ 2,069	$ 581				$ 36,677
11	PGC Unit Rate	$ 4.5259	$ 4.5259		$ 4.5259	$ 4.5259	$ 4.5259				
12	EE&C Revenue Adjustment (L5 * L13)	$ 6	$ 1,488	$ 175	$ 1	$ 13	$ 4	$ 47	$ 99		$ 1,833
13	EE&C Unit Rate	$ 0.2001	$ 0.2001	$ 0.2001	$ 0.0277	$ 0.0277	$ 0.0277	$ 0.0277	$ 0.0978	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ 14	$ 3,490	$ 411	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,915
15	USP Unit Rate	$ 0.4693	$ 0.4693	$ 0.4693							
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 3	$ 764		$ 1	$ 9	$ 3				$ 780
17	MFC Unit Rate	$ 0.1027	$ 0.1027		$ 0.0199	$ 0.0199	$ 0.0199				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 9	$ 2,212	$ 256	$ 10	$ 89	$ 25	$ 330	$ 160		$ 3,090
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500		
20	Calculated Total Margin Adjustment (L8 + L16 + L18)	$ 166	$ 41,468	$ 4,787	$ 213	$ 1,852	$ 520	$ 6,878	$ 3,254		$ 59,138
21	Total Unit Margin Adjustment (L20 / L5)	$ 5.5766	$ 5.5766	$ 5.4687	$ 4.0520	$ 4.0520	$ 4.0520	$ 4.0311	$ 3.2190	$ -	$ 5.0561

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for WNA Revenues

			WNA Revenue/Margin
Rate R	Residential-Non Htg	$	(112)
Rate R	Residential-Htg	$	(25,159)
Rate RT	RT	$	(3,630)
Rate N	Commercial-Non Htg	$	(152)
Rate N	Commercial-Htg	$	(6,395)
Rate N	Industrial	$	(313)
Rate NT	NT Total	$	(5,151)
	Total	$	(40,911)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for PGC

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual PGC Rate HTY	$7.5238	$7.5238	$4.3683	$4.3683	$4.3683	$3.9805	$3.9805	$3.9805	$4.5259	$4.5259	$4.5259	$4.5259	
September HTY PGC Rate	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	
PGC Rate Variance	($2.9979)	($2.9979)	$0.1576	$0.1576	$0.1576	$0.5454	$0.5454	$0.5454	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	2,650	6,606	8,428	11,047	8,875	6,697	3,933	1,689	1,139	1,048	1,073	865	54,050
PGC Revenue Adjustment	($7,944)	($19,805)	$1,328	$1,741	$1,399	$3,653	$2,145	$921	$0	$0	$0	$0	($16,562)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for MFC

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual PGC Rate HTY	$7.5238	$7.5238	$4.3683	$4.3683	$4.3683	$3.9805	$3.9805	$3.9805	$4.5259	$4.5259	$4.5259	$4.5259	
September HTY PGC Rate	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	
PGC Rate Variance	($2.9979)	($2.9979)	$0.1576	$0.1576	$0.1576	$0.5454	$0.5454	$0.5454	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes-Rate R	1,954	4,838	6,104	7,906	6,387	4,860	2,866	1,229	819	702	733	579	
Total PGC Volumes-Rate N	696	1,768	2,323	3,141	2,488	1,838	1,067	460	320	346	341	286	
Total PGC Volumes	2,650	6,606	8,428	11,047	8,875	6,697	3,933	1,689	1,139	1,048	1,073	865	54,050
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	($0.0681)	($0.0681)	$0.0036	$0.0036	$0.0036	$0.0124	$0.0124	$0.0124	$0.0000	$0.0000	$0.0000	$0.0000	
MFC Rate N Adj Rate	($0.0132)	($0.0132)	$0.0007	$0.0007	$0.0007	$0.0024	$0.0024	$0.0024	$0.0000	$0.0000	$0.0000	$0.0000	
Rate R Revenue Variance	($133)	($329)	$22	$28	$23	$60	$35	$15	$0	$0	$0	$0	
Rate N Revenue Variance	($9)	($23)	$2	$2	$2	$4	$3	$1	$0	$0	$0	$0	
Total Revenue Variance	($142)	($353)	$23	$30	$25	$65	$38	$16	$0	$0	$0	$0	($297)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for USP

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual HTY USP Rate	$0.4477	$0.4477	$0.4311	$0.4311	$0.4311	$0.4184	$0.4184	$0.4184	$0.4693	$0.4693	$0.4693	$0.4693	
September HTY USP Rate	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	
USP Rate Variance	$0.0216	$0.0216	$0.0382	$0.0382	$0.0382	$0.0509	$0.0509	$0.0509	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes	2,251	5,586	7,063	9,131	7,348	5,568	3,275	1,406	944	812	838	669	44,889
Total Rate R excl CAP Volumes	2,110	5,237	6,621	8,559	6,886	5,216	3,068	1,317	884	761	785	627	42,071
USP Rate Revenue Variance	$46	$113	$143	$185	$149	$113	$66	$28	$19	$16	$17	$14	$909
Total Revenue Variance	$46	$113	$143	$185	$149	$113	$66	$28	$19	$16	$17	$14	$909

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for GPC

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
GPC Rate HTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to HTY	405	972	1,226	1,581	1,279	977	582	260	178	158	159	130	7,909
Revenue Variance	$27	$64	$81	$104	$84	$65	$38	$17	$12	$10	$11	$9	$522

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(269)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,615)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for STAS

	Unadjusted 2024 TOTAL	Adjusted 2024 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (7)	$ (7)	$ (0)
Residential-Heating	$ (467)	$ (476)	$ (9)
Residential-RT	$ (47)	$ (48)	$ (1)
Total R/RT	$ (521)	$ (531)	$ (10)
Commercial-Non Htg	$ (6)	$ (6)	$ (0)
Commercial- Htg	$ (123)	$ (126)	$ (2)
Commercial-NT	$ (55)	$ (56)	$ (1)
Industrial	$ (6)	$ (6)	$ (0)
Industrial-NT	$ (3)	$ (4)	$ (0)
Total N/NT	$ (194)	$ (197)	$ (3)
Total DS	$ (42)	$ (43)	$ (1)
Total LFD	$ (49)	$ (49)	$ (1)
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (806)	$ (821)	$ (15)

UGI Utilities Inc.- Gas Division
Historic Test Year - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for EEC Rider

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Original Budget FTY R/RT Rate	$0.1625	$0.1625	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
FTY R/RT Rate	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
R/RT Rate Variance	$0.0376	$0.0376	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
R/RT Rate Volumes	2,251	5,586	7,063	9,131	7,348	5,568	3,275	1,406	944	812	838	669	44,889
R/RT Revenue Adjustment	$85	$210	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$295
Original Budget FTY N/NT Rate	$0.0316	$0.0316	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
FTY N/NT Rate	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
N/NT Rate Variance	($0.0039)	($0.0039)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
N/NT Rate Volumes	1,490	3,328	4,199	5,696	4,531	3,399	2,114	1,032	811	806	789	653	28,849
N/NT Revenue Adjustment	($6)	($13)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($19)
Original Budget FTY DS Rate	$0.0474	$0.0474	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
FTY DS Rate	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
DS Rate Variance	$0.0504	$0.0504	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	511	1,252	1,162	1,465	1,206	963	704	411	316	315	328	345	8,978
DS Revenue Adjustment	$26	$63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$89
Original Budget FTY LFD Rate	$0.0632	$0.0632	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
FTY LFD Rate	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
LFD Rate Variance	($0.0583)	($0.0583)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,855	2,219	2,334	2,789	2,478	2,275	1,961	1,683	1,485	1,461	1,586	1,549	23,675
LFD Revenue Adjustment	($108)	($129)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($238)
Total Revenue Adjustment	($4)	$131	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$127

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for GDE Rider

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual HTY DS Rate	$0.0060	$0.0060	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
September HTY DS Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
DS Rate Variance	($0.0005)	($0.0005)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	511	1,252	1,162	1,465	1,206	963	704	411	316	315	328	345	8,978
DS Revenue Adjustment	($0)	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)
Actual HTY LFD Rate	$0.0060	$0.0060	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
September HTY LFD Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
LFD Rate Variance	($0.0005)	($0.0005)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,855	2,219	2,334	2,789	2,478	2,275	1,961	1,683	1,485	1,461	1,586	1,549	23,675
LFD Revenue Adjustment	($1)	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)
Total Revenue Adjustment	($1)	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)

UGI GAS

EXHIBIT SAE-7(a) – (c)

Detail for Usage per Customer for FPFTY by Class as shown on UGI Gas Exhibit SAE-4(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.4	23,634	387,598
Rate R	16.3	19,875	323,319
Rate RT	17.1	3,759	64,279

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	88.2	604,631	53,328,454
Rate R	88.7	526,965	46,726,844
Rate RT	85.0	77,666	6,601,610
Rate RT Total	81.9	81,425	6,665,889

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	410.1	4,474	1,834,787
Rate N	249.7	2,905	725,429
Rate NT	622.0	1,545	960,990
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	552.0	65,074	35,920,848
Rate N	340.2	44,718	15,214,480
Rate NT	703.3	19,240	13,531,492
Rate DS	6,429.1	1,116	7,174,876
Rate Commercial NT Total	697.3	20,785	14,492,482

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,542.6	1,252	3,183,335
Rate N	905.4	596	539,625
Rate NT	2,085.5	466	971,843
Rate DS	8,799.3	190	1,671,867
Rate NT Total	727.7	21,251	15,464,325
Rate DS Total	6,763.2	1,330	8,995,111

Detail for Usage per Customer for FTY by Class as shown on UGI Gas Exhibit SAE-5(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.4	24,181	396,568
Rate R	16.3	20,422	332,290
Rate RT	17.1	3,759	64,279

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	88.4	598,421	52,900,416
Rate R	88.9	520,755	46,298,806
Rate RT	85.0	77,666	6,601,610
Rate RT Total	81.9	81,425	6,665,889

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	410.1	4,547	1,864,725
Rate N	253.6	2,978	755,367
Rate NT	622.0	1,545	960,990
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	552.0	64,902	35,825,904
Rate N	339.7	44,547	15,131,875
Rate NT	703.3	19,240	13,531,492
Rate DS	6,423.8	1,115	7,162,537
Rate Commercial NT Total	697.3	20,785	14,492,482

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,542.6	1,280	3,254,528
Rate N	978.4	624	610,552
Rate NT	2,085.5	466	971,843
Rate DS	8,800.7	190	1,672,133
Rate NT Total	727.7	21,251	15,464,325
Rate DS Total	6,759.2	1,329	8,983,038

Detail for Usage per Customer for HTY by Class as shown on UGI Gas Exhibit SAE-6(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.4	24,851	407,556
Rate R	16.3	21,169	344,594
Rate RT	17.1	3,682	62,962

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	88.5	592,297	52,418,285
Rate R	89.0	516,400	45,967,040
Rate RT	85.0	75,897	6,451,245
Rate RT Total	81.9	79,579	6,514,207

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	410.1	4,619	1,894,252
Rate N	234.1	3,076	720,197
Rate NT	622.0	1,522	946,684
Rate DS	10,827.2	21	227,371

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	552.0	64,510	35,609,520
Rate N	316.9	44,383	14,066,457
Rate NT	703.3	19,007	13,367,623
Rate DS	7,299.5	1,120	8,175,440
Rate Commercial NT Total	697.3	20,529	14,314,307

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,542.6	1,285	3,267,241
Rate N	1,235.7	667	824,225
Rate NT	2,085.5	457	953,074
Rate DS	9,254.3	161	1,489,942
Rate NT Total	727.5	20,986	15,267,381
Rate DS Total	7,598.1	1,302	9,892,754

UGI GAS

EXHIBIT SAE-8

UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation

Notes:

1/ Storage Trip Cost ($/mcf) 0.1460

2/ Weekend Load Reduction Factor (%) 15.2%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 **WD = (1/(1 - WELF)) * WE**
= (1/(1 - 0.15)) * WE
WD = 1.18 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7**
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.15)) + 2] * WE] / 7
7.90 * WE / 7
Step 2 WE = 0.89 * AVERAGE

4/ EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE)
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) - 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.15)) - 2) * WE] - (3 * AVERAGE)
3.90 * WE - (3 * AVERAGE)
0.47 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.47 x Average) / (7 x AVERAGE)] x 0.133
0.07 x 0.146
0.0102

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0102 x 20
0.2040

Notes:

1/ Weighted average of storage trip costs based on SCQ of storages

2/ Aggregate load reduction for all non-Choice transportation customers electing NNS
Weekend Load Reduction factor percentage based on historical data for the period Oct 2023 through Sep 2024

3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days

4/ Assumes levelized deliveries on all days

UGI GAS

EXHIBIT SAE-9

UGI Utilities, Inc. - Gas Division
Monthly Balancing Service (MBS) Rate Calculation

Notes:

1/	Average Capacity Charge for Storage ($/mcf)	1.3070	(A)
2/	Anticipated Average Monthly Imbalance %	0.6786%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.2%	(C)
LFD	57.7%	(C)
XD Firm	57.3%	(C)
Transportation System Average	50.6%	(D)

MBS Rate Formula
E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0128	(E)
LFD	0.0074	(E)
XD Firm	0.0075	(E)

1/ Weighted average of storage capacity and demand costs based on SCQ of storages
2/ Average monthly imbalance percentage includes all non-Choice transportation customers electing MBS
Average monthly imbalance percentage based on historical data for the period Oct 2023 through Sep 2024
3/ Load Factors based on FPFTY throughput and peak capacity for applicable customers by rate class

UGI GAS

EXHIBIT SAE-10

UGI Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

		Rate R/RT	Rate N/NT
Total Uncollectible Revenue Requirement	$ 22,245,065		
Allocator 1/		92.92%	6.96%
Uncollectible Revenue Requirement		$ 20,670,114	$ 1,548,257
Total Proposed Revenue		$ 806,644,967	$ 275,340,828
MFC % 2/		2.56%	0.56%

1/ The allocator is based on a 3-year average of uncollectible expenses.
2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS STATEMENT NO. 9

CHRISTOPHER R. BROWN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. - Gas Division

Statement No. 9

Direct Testimony of
Christopher R. Brown

Topics Addressed:	**Natural Gas Operations** **Regulatory Compliance** **System Safety and Reliability** **Leak Reductions & Emergency Response** **Safety Initiatives** **Environmental Programs**

Dated: January 27, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed as the Vice President of Operations by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two (2) operating divisions, the Gas Division ("UGI Gas" or the "Company) and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit CRB-1 to my testimony.

Q. What are your responsibilities as Vice President of Operations?

A. As Vice President – Operations, I am UGI's senior executive accountable for approximately 830 individuals including management, clerical, and field technicians that operate and maintain the Company's gas transmission and distribution system. I am also responsible for overseeing activities and personnel involved with the Company's capital planning department, buildings and grounds, fleet, physical security, and business continuity programs.

Q. Have you presented testimony in proceedings before the Commission?

A. Yes. UGI Gas Exhibit CRB-1 identifies my prior testimony.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the following topics: (1) natural gas system operations; (2) regulatory compliance; (3) system safety and reliability; (4) leak reductions and emergency response; (5) safety initiatives; and (6) environmental programs. Within these topics, I support several adjustments related to the Company's claim, specifically related to: (1) leak surveys; (2) pipeline material verification; and (3) pipeline contractor price increases.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibit CRB-1.

II. NATURAL GAS SYSTEM OPERATIONS

Q. Please provide an overview of the Company's distribution system.

A. UGI Gas provides service to approximately 700,000 residential, commercial, and industrial customers located in 45 of Pennsylvania's 67 counties and spanning more than 700 municipalities. As of September 30, 2024, the Company operates more than 12,000 miles of gas distribution mains and 300 miles of natural gas transmission mains in the Commonwealth of Pennsylvania.

Q. Please describe UGI Gas's operations centers and support facilities.

A. UGI Gas has operations centers and support facilities throughout its service territory. Additionally, a stand-alone centralized training center facility ("Learning Center") in Reading, PA, which includes a "safety town" for real-life indoor and outdoor training inclusive of leak pinpointing and investigation, a separate welding and tapping center, a safety lab, a service lab, a measurement and regulation lab, and a construction and maintenance lab. The UGI Gas Learning Center supports Operator Qualification training for both UGI Gas employees as well as contractors.

Q. How does UGI Gas staff its operations?

A. UGI Gas relies upon a mix of employees and contractor resources for its capital, operations, and maintenance programs to accomplish many of its initiatives, including gas main and service replacement and installation, roadway and landscape restoration, leak repairs, meter reading, new business activities, and general system operation and maintenance. Further, UGI Gas's parent company, UGI Corp., provides management, administrative, and support services (*e.g.*, executive management, human resources, legal, finance, accounting, procurement, treasury, IT, and corporate governance).

Q. As related to the use of contractor resources, has UGI Gas seen an increase in the pipeline construction costs since its budget was finalized?

A. Yes, late in 2024, UGI Gas received the results from its request for proposal ("RFP") for pipeline construction and maintenance, contained within a Master Pipeline Construction Agreement ("MPCA") (the "2025 RFP"). The results of the 2025 RFP reflect an expected increase of 17.5% over the expense base budget amount of $9.196 million (base budget reflects no pricing change).

Q. Please describe the Company's use of contractors for its main replacement and other maintenance activities.

A. UGI Gas utilizes contractor resources to perform construction and maintenance activities on the natural gas distribution system, including main and service line replacement, valve inspections, leak repairs, spotting facilities, corrosion mitigation, traffic control, sidewalk and roadway restoration, and others.

Q. How are contractors selected to perform work at UGI Gas?

A. UGI Gas utilizes a competitive bid process, typically on a three-year cycle, and awards blanket style construction agreements to multiple incumbent and incremental contractors who bid on each region within the Company's service territory. The contracts are awarded based on key factors of price, capability, and safety record. Using this process, UGI Gas was successful in maintaining consistent costs for a majority of the pipeline construction contractors from 2022 until the most recent RFP in which pricing will become effective on March 1, 2025.

Q. Please describe the 2025 RFP process.

A. UGI Gas typically uses three-year contract terms for its blanket construction contractors. The table below shows the critical date for the 2025 RFP impacting contractor costs in this proceeding:

Table 1: Critical Dates for the 2025 RFP

Category	Contract	RFP Issued	Contract Effective	Contract Expiration
Pipeline/Construction	MPCA	7/24/2024	3/1/2025	2/29/2028

Q. Please describe the results of the 2025 RFP.

A. The results of the 2025 RFP reflect price increases across the range of services provided by the bidders. As intended, UGI Gas was successful in attracting several additional contractor bids throughout the various bid regions established within these contracts. RFPs were sent to 29 contractors (including 16 who were not currently under a blanket contract with UGI Gas), and 22 contractors responded with a bid, indicating a competitive market.

Q. What is driving the increase in prices reflected in the RFP results?

A. The pipeline construction labor market is constrained. To secure skilled labor, contractors must pay higher labor rates, and those higher rates are passed on to UGI Gas. In addition, the scope of units included in the contract includes more work than the previous contract. For example, a contractor is now required to collect certain installed distribution asset data that previously was not required, resulting in longer times to complete a similar number of units of work. This is just one example where the requirements within the Company's Gas Operations Manual ("GOM") have increased since the last contract negotiation, and contractors are reflecting the cost to comply with these requirements in their bids.

Q. Have you quantified the impact of the increased contractor costs on the operating expense claim for the FPFTY?

A. Yes, the Company has quantified the impact of the increased contractor costs on its operating expense claim, as shown on Schedule D-18 of UGI Gas Exhibit A – Fully Projected. As shown on Schedule D-18, UGI Gas's budget for pipeline contractor expense in this case for the FPFTY was $10.116 million, with this amount being inclusive of an estimated increase in contractor cost of 10% to address cost increases that would likely result from the RFP process described above. However, the actual increase realized through the RFP process was 17.5%, bringing the total contractor costs for the FPFTY to $10.803 million. Accordingly, a proforma adjustment of $687,000 ($10.803-$10.116) is included to reflect these known incremental cost increases for the FPFTY, as shown on Line 4 of Schedule D-18.

III. <u>REGULATORY COMPLIANCE</u>

Q. What regulations govern the safe transportation of natural gas transmission and distribution pipelines?

A. UGI Gas is subject to the minimum federal pipeline safety regulations in 49 CFR § 192 - Transportation of Natural and Other Gas by Pipeline ("Part 192"). The Company must also follow the applicable state pipeline safety requirements found in Pennsylvania Title 52, Chapter 59 - Gas Service and Hazardous Liquid Service ("Chapter 59"). Pennsylvania natural gas pipeline safety regulations found in Chapter 59 of the Commission's regulations generally follow the Part 192 regulations.

Q. What are the regulatory topics included in Part 192 regulations?

A. Part 192 covers all aspects pertaining to the design, construction, operation, and maintenance of natural gas pipelines owned and operated by the Company. Federal natural gas pipeline safety regulations mandate that Operators have procedures and processes touching upon the following:

- Design & Construction Standards
- Operation & Maintenance Procedures
- Emergency Plans
- Integrity Management Plans
- Damage Prevention Plans
- Public Awareness Programs
- Control Room Management Plans

Q. How has the Company complied with these regulations?

A. UGI Gas has several plans and procedural manuals in place to address all required regulations found in Part 192. Due to the requirements found in Part 192, specifically Subpart M which promulgate the maintenance requirements in Part 192, UGI Gas performs a multitude of safety checks annually across its distribution system to maintain system safety and reliability.

Q. Can you provide examples of compliance safety checks UGI Gas performs annually on its distribution system to comply with Part 192?

A. The Company's Gas Operations personnel perform several activities to comply with applicable Part 192 regulations as well as internal Company procedures. Some of these activities include, but are not limited to, the following:

- Pipeline Leak Surveys and Patrols
- Valve Maintenance and Inspection
- Regulator Station Inspection and Maintenance

- Service Line Leak Survey and Meter Inspection
- Atmospheric Corrosion Inspection
- Cathodic Protection Inspection and Maintenance
- Odorant Intensity Inspection
- Transmission Integrity Management Assessments

The activities mentioned above are performed throughout the year and in certain situations, multiple times on the same distribution or transmission asset annually. This work also requires significant work management scheduling and record retention management. Throughout the year, the Company's Gas Operations personnel perform several thousand safety checks across its distribution system.

Q. Does the Company undertake any voluntary actions that exceed federal requirements found in Part 192?

A: Yes, UGI Gas's plans and procedures exceed federal safety standards in a number of areas. Additionally, UGI Gas voluntarily adopted and implemented programs identified as industry wide best practices. One such example includes UGI Gas's implementation of American Petroleum Institute ("API") Recommended Practice 1173 – Pipeline Safety Management Systems ("PSMS"). UGI Gas's PSMS program is still in development and continues to work toward full implementation in order to promote an enhanced safety culture and provide safe and reliable natural gas service to its customers.

In other situations, UGI Gas has elected to implement other voluntary actions that arise from national events or recommendations by the National Transportation Safety Board ("NTSB") and other governmental agencies. As an example, following over-pressurization prevention guidance issued by the NTSB in 2019, UGI Gas evaluated the over-pressurization protection ("OPP") utilized on its low-pressure systems. A total of 73 regulator stations serving over 80,000 customers required supplemental OPP to implement the NTSB's recommendations on OPP. The supplemental OPP recommended by the NTSB exceeded the minimum requirements specified in Part 192. UGI Gas implemented a plan to address supplemental OPP at all 73 stations. As of September 30, 2024, 72 of the 73 stations have been addressed through the installation of supplemental OPP, station abandonment, or regulator station replacement. These projects were prioritized on a risk reduction basis seeking to maximize the customers served by regulator stations that included the supplemental OPP. The final station, which provides service to the last approximately 150 customers of the 80,000 total customers, is expected to meet the NTSB recommendations on OPP by September 30, 2025, which will complete the OPP enhancement program.

Q. Does the Company have integrity management plans?

A. Yes, the Company maintains a Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP") as mandated in 49 C.F.R. § 192, Subpart O – Gas Transmission Pipeline Integrity Management, and Subpart P – Gas Distribution Integrity Management.

Under Subpart O, UGI Gas must continually identify threats to its pipelines in high consequence areas ("HCAs"), moderate consequence areas ("MCAs"), and other designated areas along transmission lines to determine the risk posed by any identified threats. UGI Gas also must schedule and perform integrity assessments to address all applicable threats, collect information about the condition of the pipelines, and take risk reduction actions to minimize and mitigate applicable threats.

Under 49 C.F.R. § 192, Subpart P, operators of gas distribution pipelines are mandated to gather information regarding their distribution pipelines and identify and evaluate relevant threats to their distribution systems. Operators are also required to assess and prioritize risks associated with the distribution system, implement accelerated action aimed at mitigating the risks of pipeline failures, and assess the effectiveness of these actions. Furthermore, operators must establish and execute a process for the regular review and enhancement of their programs, as well as report their findings to regulatory authorities. Unlike TIMP, DIMP encompasses the entire distribution system rather than focusing solely on pipelines located in select areas along transmission lines. This is due to distribution pipelines being predominantly situated in urbanized, densely populated regions to supply gas to these communities.

Q. Does the Company train and qualify its field personnel prior to performing operations and maintenance activities on natural gas pipelines?

A. Yes, UGI Gas maintains an Operator Qualification Plan ("OQ Plan") complying with the requirements of 49 CFR § 192, Subpart N. The OQ Plan establishes requirements for and management of qualifications for pipeline personnel who perform covered tasks on a pipeline. UGI Gas's OQ Plan includes over 145 unique covered tasks. Pipeline personnel are trained and qualified under the tasks needed to perform their various work activities on a UGI Gas pipeline. Covered tasks ensure internal and external pipeline personnel are educated, tested, and competent to perform specific natural gas activities on UGI Gas's distribution system.

Q. Are revisions made to the federal regulations found in Part 192?

A. Yes, periodically the Pipeline and Hazardous Material Safety Administration ("PHMSA") issues notices of proposed and final rulemakings that inform natural gas pipeline operators of proposed and final revisions made to federal regulations. A list of recent PHMSA rulemakings and their status are available publicly online. Rulemakings generally takes months to years to complete depending on the extent of the proposed revisions.

Q. What impacts do revisions to federal regulations pose to the Company?

A. Recently, PHMSA proposed and adopted substantial revisions to the federal regulations, which significantly affected the Company. As an example, PHMSA promulgated a rulemaking titled "Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure ("MAOP") Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" ("Gas Transmission Final Rule") published in the Federal Register on October 1, 2019, with an effective date of July 1, 2020. This rulemaking was arguably the single largest change to natural gas transmission pipeline safety regulations since Part 192 was originally published in 1970. More specifically, two new regulations out of many revisions were introduced under Title 49:

- § 192.607 - Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.
- § 192.624 - MAOP reconfirmation: Onshore steel transmission pipelines.

These new regulations require UGI Gas to reconfirm the MAOP and, when applicable, material specifications of transmission pipelines that do not have a traceable, verifiable, and complete MAOP records. Accordingly, UGI Gas reviewed its records and documentation pertaining to all its transmission assets and created a schedule in accordance with the MAOP reconfirmation timelines specified under 49 CFR § 192.624.

PHMSA also proposed rulemakings regarding Leak Detection and Repair ("LDAR") and Safety of Gas Distribution Pipelines, which are still not finalized and published in Part 192. These are extensive changes (as described further herein) to the current federal regulations and would require UGI Gas to increase financial and labor resources to comply with the proposals. The Company continues to closely monitor the status of all proposed PHMSA rulemakings as well as other agencies, such as the U.S. Environmental Protection Agency ("EPA") and the Occupational Safety and Health Administration ("OSHA").

Q. Please discuss UGI Gas's Material Verification Plan.

A. UGI Gas has a formal Material Verification ("MV") Plan as part of its TIMP that outlines the procedures and requirements to meet the MV requirements in federal code under 49 CFR § 192.607. The verification of material properties and attributes for transmission pipelines is required when an operator does not have traceable, verifiable, and complete ("TVC") records. Federal code stipulates that for pipeline populations (segments of pipe that have the same material characteristics such as wall thickness, grade, manufacturing process and dates, and construction dates), MV must occur at a minimum of one excavation per mile along the pipeline.

UGI Gas's MV Plan defines what pipeline segments require MV, which includes pipeline segments that have missing or incomplete TVC pressure test data needed for MAOP reconfirmation. UGI Gas has also committed to voluntarily gather material and component attributes on an opportunistic basis for all other transmission pipeline segments without TVC records to provide material attributes for anomaly repairs, Engineering Critical Assessments, and predicted failure pressure calculations.

Q. How many pipeline segments does UGI Gas have in the MV Plan?

A. UGI Gas has identified 36 transmission pipelines that have segments that need material verification. Since August 2020, UGI Gas has completed 87 MV tests (approximately 22 per year) based primarily on opportunistic excavations, which are those related to other pipeline activities. UGI Gas has an estimated 323 MV tests remaining, which can be reduced to 262 MV tests, if the Company accounts for anticipated bare steel main replacements planned to occur before the applicable reconfirmation timelines, thereby eliminating the need to perform MV. The MV process requires technical expertise and equipment. Historically, costs for targeted MV tests including labor, materials, and overhead have averaged near $38,000 per test. These costs have historically been treated as expense items.

Q. How will UGI Gas accelerate its MV Plan?

A. UGI Gas anticipates that as material verification is completed for certain pipeline segments, future opportunistic excavations will be limited based on the remaining required segment population. In other words, UGI Gas will need to proactively plan and execute on MV activities to complete the work. UGI Gas will strategically target specific pipeline populations. Starting in Fiscal Year 2026, UGI Gas will increase the number of material verifications to an average target of 35 per year, which will allow for a targeted completion by Fiscal Year 2032. These annual MV targets will include a combination of opportunistic and strategic approaches. The additional 13 MVs over the historic yearly average of 22 will cost an additional estimated $494,000 per year over the current program and is included in Schedule D-17 of UGI Gas Exhibit A – Fully Projected. This will allow UGI Gas to complete its MV Plan for transmission pipelines and stay in compliance with MAOP reconfirmation timelines.

IV. SYSTEM RELIABILITY AND SAFETY

Q. Please describe the physical composition of UGI Gas's distribution system.

A. Due to its long-term operation, the Company's distribution system includes a mixture of pipeline materials indicative of the industry's technological advancement over time. Cast iron mains can be found in the oldest parts of the initial system. UGI Gas, and the industry in general, then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include polyethylene ("PE") and coated steel piping. Overall, approximately ninety percent (90%) of UGI Gas's distribution mains consist of contemporary materials, which UGI Gas defines as cathodically protected steel and modern plastic. UGI Gas's natural gas distribution system has the highest percentage of contemporary mains among major natural gas distribution companies in Pennsylvania.

Q. Please discuss the Company's actions to improve and enhance its distribution system.

A. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis through Commission-approved Long Term

Infrastructure Improvement Plans ("LTIIP"). The Company's Initial LTIIP[1] and Second LTIIP[2] have resulted in UGI Gas successfully removing more than 730 miles of main over the 11-year period from 2014 to 2024, including ninety-three percent (93%) of its total cast iron mains and forty-three percent (43%) of its total bare steel/wrought iron mains.

UGI Gas will continue to invest in improving and modernizing its distribution facilities serving customers throughout the Company's service territory. The Company filed its Third LTIIP in August 2024, and this plan was approved by the Commission on December 5, 2024, at Docket No. P-2024-3050769. The Third LTIIP includes the replacement of another 310-340 total miles of cast iron, bare steel, wrought iron, and priority plastic main during the 5-year LTIIP period. In addition to main replacements in the Third LTIIP, the Company is pursuing other infrastructure initiatives including replacing service lines, meter sets, valves, farm taps, as well as addressing safety upgrades relating to measurement and regulation facilities (e.g., making improvements to over-pressure protection equipment) and remediating mechanical tees. Additionally, the Company outlined a plan for replacement of priority plastic, which includes plastic installed between 1965 and 1985. These initiatives will make UGI Gas's system safer and more reliable. Continuing UGI Gas's infrastructure replacement program will allow the Company to provide safe and reliable service both now and into the future.

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[1] On December 12, 2013, each of UGI Gas's three predecessor natural gas distribution companies filed Petitions, and received Commission approval, for LTIIPs at Docket Nos. P-2013-2398833, P-2013-2397056, and P-2013-2398835 (collectively referred to as the "Initial LTIIP"). In the Initial LTIIP, the Company identified its plan to replace all its cast iron main over the 13-year period ending in February 2027 and all of its bare steel and wrought iron main over the 28-year period ending September 2041. The Initial LTIIP period ended on December 31, 2019.

[2] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Petition filed on August 21, 2019) (the "Second LTIIP"). The Second LTIIP builds off the significant acceleration in the rate of infrastructure repairs, improvements, and replacements (including the accelerated replacement of cast iron and bare steel pipe) that was achieved by the Initial LTIIP and reflects even further acceleration.

Q. How does UGI Gas prioritize its pipeline replacement projects?

A. In 2019, UGI Gas began using the Data-Driven risk model ("DDRM"). The DDRM is a quantitative model incorporating leak repair data, incident data, and asset population data to calculate a risk index score for facility groupings referred to as Asset Threat Groups ("ATGs"). The DDRM is utilized in conjunction with the Subject Matter Expert ("SME") driven risk model in order to validate DDRM results by incorporating SME input. Optimain, a risk evaluation software tool, also continues to be utilized to evaluate risk on an individualized main segment level and assists in validating DDRM outputs for cast iron and steel mains.

The DDRM provides a quantitative basis for evaluating risk and creates a stable foundation for comparing year-over-year changes because of the consistent quantitative underpinning utilized. Finally, the DDRM helps UGI Gas better evaluate other effective approaches for addressing risk, including effective operations and maintenance programs, additional leak survey activities and damage prevention measures.

Q. What are the Company's current goals for main replacement?

A. UGI Gas is on track to replace all its cast iron main no later than February 2027, consistent with its initial completion plan and prior commitments. Further, the Company plans to complete its bare steel and wrought iron main replacement no later than September 2041, also consistent with its initial completion plan. Specifically, to maintain a pace of replacement that would achieve these objectives, the Company's Third LTIIP established the objective of replacing between 50 and 60 miles of main in calendar year 2025, and between 60 to 70 miles of main per year in calendar years 2026 - 2029. An additional 15 miles of wrought iron and bare steel are planned to be replaced in calendar year 2027 due to corrosion.

Q. Did UGI Gas achieve its mileage objective in the first four years of its Second LTIIP?

A. Yes, the Company achieved and exceeded its mileage objective, by replacing or retiring over 295 miles of main in 2020 through 2023.

Q. What is UGI Gas's projection of its replacement and betterment plant in service for the future test year ("FTY") and the fully projected future test year ("FPFTY")?

A. For the FTY, the replacement and betterment budget reflects $315.5 million plant in service. The FPFTY plant placed in service for replacement and betterment is budgeted to be $327.8 million. For more detail on the Company's budgeting process related to all planned capital activities, please refer to the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

Q. What is the Company's basis for showing a further increase in plant placed in service in the FTY and FPFTY?

A. Foremost, the Company's annual plant additions related to replacement and betterment activities increased nearly $70 million over the 2020-2024 period, from $306 million in 2020 to $376 million in 2024. The Company anticipates that the cost of its replacement and betterment work will continue to increase through the FPFTY due to a number of different elements. First, the Company is further accelerating the number of miles it will accomplish in the FTY and FPFTY. In addition, these miles of main include large portions of the remaining cast iron main replacement projects, which are planned to be completed by 2027, and consist of projects featuring increased complexity, challenging locations, and in many cases larger diameter pipes. Additionally, the cost of contractor labor to complete this work is continuing to increase. For these reasons, UGI Gas's budget for the FTY and the FPFTY reflects increased plant additions beyond the amount that the Company had accomplished during the HTY.

Q. What other system reliability improvements has the Company performed recently?

A. In addition to pipeline replacement, the Company's Third LTIIP includes a project related to natural gas system over pressure protection ("OPP") as discussed above. UGI Gas also recently completed an implementation plan to add remote pressure monitoring capabilities to its low-pressure systems. These capabilities include real-time alarm notifications to allow expedited system pressure correction and adjustment. As of September 30, 2024, all remote pressure monitoring deployment was completed.

Additionally, UGI Gas completed pressure reinforcement projects in the Jersey Shore, Macungie, and Wyomissing areas of its service territory within the last two years. Finally, the Company completed significant improvements to four city gate stations as well as two district regulator stations.

V. LEAK REDUCTIONS AND EMERGENCY RESPONSE

Q. Please discuss UGI Gas's efforts to identify, manage, and reduce system leaks.

A. UGI Gas monitors safety and reliability indicators for its natural gas distribution system on an ongoing basis to evaluate corrosion and leak identification and resolution performance, track emergency response, and pursue damage prevention – all of which will drive improvements in employee and public safety. As a part of its DIMP,[3] UGI Gas regularly re-assesses system risks and leak trends to determine if additional or accelerated actions are required to further reduce system leaks.

Leak surveys are an important tool for discovering, monitoring, and remediating leaks. To enhance its leak identification capabilities, UGI Gas is currently working to finish evaluation of Advanced Mobile Leak Detection ("AMLD") technology, including completed pilot surveys in 2024 to discover leaks on mains and adjacent service lines. AMLD is a recent development in methane detection technology that offers higher methane detection sensitivities when compared to traditional leak survey technologies that the Company employs. AMLD involves the collection of various data points while performing a mobile leak survey; once data is collected, a list of prioritized leak indications is generated for the Company to review and investigate. AMLD technologies incorporate methane detection capabilities in parts per billion (ppb) which provides highly precise data that is 1,000 times more sensitive than most leak detection sensors currently available. AMLD technologies allow natural gas leak plume data to be collected and interpreted from a distance and at a speed and scale not previously possible.

An additional benefit of the AMLD technology is the ability to quantify methane emissions associated with UGI Gas's distribution system. AMLD technology can measure large volume leaks, over 10 standard cubic feet per hour (scfh), allowing UGI Gas to prioritize leaks that are a hazard to the environment. Methane emission quantification also allows for the highest-emitting leaks to be identified and targeted for expedited repair or replacement. This technology is a more efficient method that may be used to identify

[3] 49 C.F.R. § 192.1007.

methane emission sources over a greater number of miles in a more rapid and cost effective manner than traditional survey methods.

This work by UGI Gas is of particular importance as PHMSA is proposing significant regulatory revisions within its proposed LDAR rulemaking, which is anticipated to become final in early 2025. Significant changes to leakage survey and patrolling requirements, performance standards for advanced leak detection programs, enhanced leak survey frequencies for vintage plastic mains, and several other revisions to Part 192 are part of this rulemaking. These newly proposed regulatory requirements regarding leak detection and repair will have significant impacts to UGI Gas's operating expenditures. When finalized, the new rules will introduce more frequent leak survey frequencies for most transmission and distribution asset mains and service lines. With the increase in leak survey frequency requirements and use of new advanced leak detection technologies, UGI Gas will be positioned to detect, classify, and schedule for repairing natural gas leaks in a more proactive manner, while giving further considerations to environmental risk factors, consistent with the new rules.

Q. What impact will these new LDAR requirements have on the Company's claimed costs in this proceeding?

A. The incremental cost related to compliance with the new LDAR rules was not included in the Company's budget for the FPFTY period. Accordingly, the table below summarizes the estimated annual cost impact that UGI Gas anticipates based upon these new LDAR federal requirements for accelerated leak surveys of transmission and distribution mains.

These amounts are reflected as an adjustment, Adjustment #1, in Schedule D-13 of UGI Gas Exhibit A (Fully Projected).

Table 2: Transmission & Distribution Line Surveys

Description	Annual OPEX Cost
Transmission Line Leak Surveys & Patrols	$ 1,531,607.40
Distribution Line Leak Surveys	$ 328,898.61

Q. Are there other leak survey impacts related to the LDAR rules which UGI Gas is implementing?

A. Yes, the required leak survey frequency for priority plastic is increased as part of the rulemaking. Priority plastic installed in the UGI Gas system contains DuPont Aldyl A plastic pipe, which can be susceptible to failures over time dependent upon local environmental conditions and installation practices. Aldyl A has long been documented by the natural gas industry as susceptible to early failures and has been highlighted in the Commission's recent Tentative Order.[4] The total length of priority plastic mains installed on UGI Gas's distribution system between the years of 1965 and 1985 is approximately 1,100 miles. Current leak survey frequencies for this asset population are generally on a 5-year cycle in line with federal regulations, although UGI Gas typically performs these surveys on a 4-year cycle. UGI Gas is proposing to perform annual leak surveys on this asset population beginning in Fiscal Year 2026. This proposed leak survey frequency is consistent with the proposed frequency in PHMSA's LDAR rulemaking. Regardless of the pending LDAR rule, UGI Gas is moving forward with making this survey frequency

[4] See *Replacement of Older Plastic Pipe in Natural Gas Distribution Systems*, Docket No. M-2024-3050313 (Tentative Order entered Aug. 26, 2024).

change in recognition of the need to increase monitoring and data collection on priority plastic assets. The expansion of leak surveys on the Company's priority plastic main population will provide additional safety checks to detect any leaks or failures more proactively. Importantly, this data feeds into the Company's DIMP for evaluation, risk ranking, and replacement prioritization.

Q. What impact will the increase in vintage plastic leak survey frequency have on the Company's claimed costs in this proceeding?

A. The incremental cost related to moving to annual surveys for vintage plastic assets is estimated at $200,000. This amount is reflected as an adjustment, Adjustment #2, in Schedule D-13 of UGI Gas Exhibit A (Fully Projected).

Q. How has the Company implemented AMLD Technology to date?

A. UGI Gas began its initial pilot of AMLD in 2021. The Company purchased one AMLD device and subsequently installed it on a Company vehicle. During the initial phase, the vehicle was driven along 445 miles of main in the Northern district. In subsequent years, UGI Gas continued to pilot this unit and other competing AMLD technologies within its service territory to aid in the analysis and development of its AMLD program. AMLD technology allowed UGI Gas to perform mobile main-line leak survey at speeds five to 10 times greater than traditional main line survey. A variety of distribution materials were included within these survey pilots, such as bare steel, coated steel, and various vintages of plastic to better understand each populations' emission rates. When leaks were detected through AMLD, they were investigated using traditional leak survey methods to ensure current compliance with internal and regulatory standards. Through this entire process, UGI Gas was able to analyze the full range of capabilities AMLD can offer to the Company.

Q. What are UGI Gas's long-term plans for AMLD Technology?

A. UGI Gas will leverage the AMLD vehicle in Fiscal Year 2025 to continue quantifying methane emission rates in targeted geographic areas of UGI Gas's distribution system. The Company will also finalize its processes and resources related to AMLD technology for the full integration of AMLD technology into UGI Gas's leak detection program.

Beyond Fiscal Year 2025, UGI Gas is proposing to utilize AMLD technology on 20% of its drivable mains annually in addition to the Company's traditional leak survey schedule for mains and service lines in compliance with all current standards and federal regulations. The Company's AMLD plan will quantify the emission rates of its entire distribution system within five years. This new proposed survey cycle will add meaningful data points regarding the Company's mains and service lines while identifying new environmental risk reduction opportunities not otherwise afforded to UGI Gas. This information will also be leveraged within UGI Gas's DIMP to provide additional information and knowledge to the asset populations contained within the DIMP.

UGI Gas will leverage this technology to quantify methane emissions from transmission and distribution pipelines owned and operated by UGI Gas. With the increase in leak survey frequencies, UGI Gas will be better positioned to detect, classify, and schedule the repair of natural gas leaks in a proactive manner while providing further considerations to environmental risk factors.

Q. Does the use of AMLD technology align with the anticipated finalized PHMSA LDAR rules?

A. Yes. UGI Gas's leak detection program which continues to pilot AMLD technology, aligns with PHMSA's proposed regulations. It is important that UGI Gas continue expanding its efforts not only to position itself for compliance with PHMSA's proposed regulations, but also to recognize that the AMLD technology benefits the Company, its customers, and the public by improving system safety and reliability and reducing greenhouse gas emissions.

Q. What are the expected annual operating costs of UGI Gas's AMLD plan?

A. UGI Gas expects the annual financial operating expenditures to be approximately $1.7 million based upon the 5-year proposed frequency rate. This cost was based upon the piloted use of UGI Gas's AMLD vehicle as well as the additional costs associated with new leak indications that UGI Gas would expect to encounter and investigate.

Q: Have the increased costs for AMLD been included within the Company's claim in this proceeding?

A: Yes, these incremental costs are reflected as an adjustment, Adjustment #3, as shown on Schedule D-13 of UGI Gas Exhibit A (Fully Projected).

Q. How does UGI Gas classify leaks?

A. UGI Gas uses a standardized leak classification system consistent with general industry protocols. Specifically, underground leaks are classified as 'A,' 'B,' and 'C.' Class 'C' leaks are deemed hazardous and repair work is undertaken immediately. Class 'B' leaks are non-hazardous at the time of detection but justify a scheduled repair. Pursuant to UGI Gas's practice, Class 'B' leaks must be repaired or cleared within one calendar year, but no later than 15 months from the date of the latest Class 'B' leak classification. UGI Gas has been focused on continuous improvement for Class 'B' leak repairs. To that end, the Company repaired 97.3% of Class 'B' leaks within six months of classification in Fiscal Year 2024. These accelerated repairs reduced the leak hazards as well as methane emissions. Class 'A' leaks are deemed non-hazardous and are monitored for changes in severity.

In December 2023, UGI Gas established formal classifications and procedures for aboveground leaks on UGI Gas owned facilities. Prior to this, UGI Gas did not classify aboveground leaks. These aboveground leaks are classified as Class 'G' and 'H.' Class 'G' leaks are defined as a minor escape of gas from aboveground UGI Gas piping or related gas facilities that is in a location that does not endanger the public and should be repaired or cleared within five calendar years, not to exceed 63 months from the date of the latest Class 'G' leak classification. Class 'H' leaks are defined as an unintentional escape of gas from aboveground UGI Gas piping or related gas facilities that requires immediate repair or make safe action.

Q. How have UGI Gas's system leaks improved since 2018?

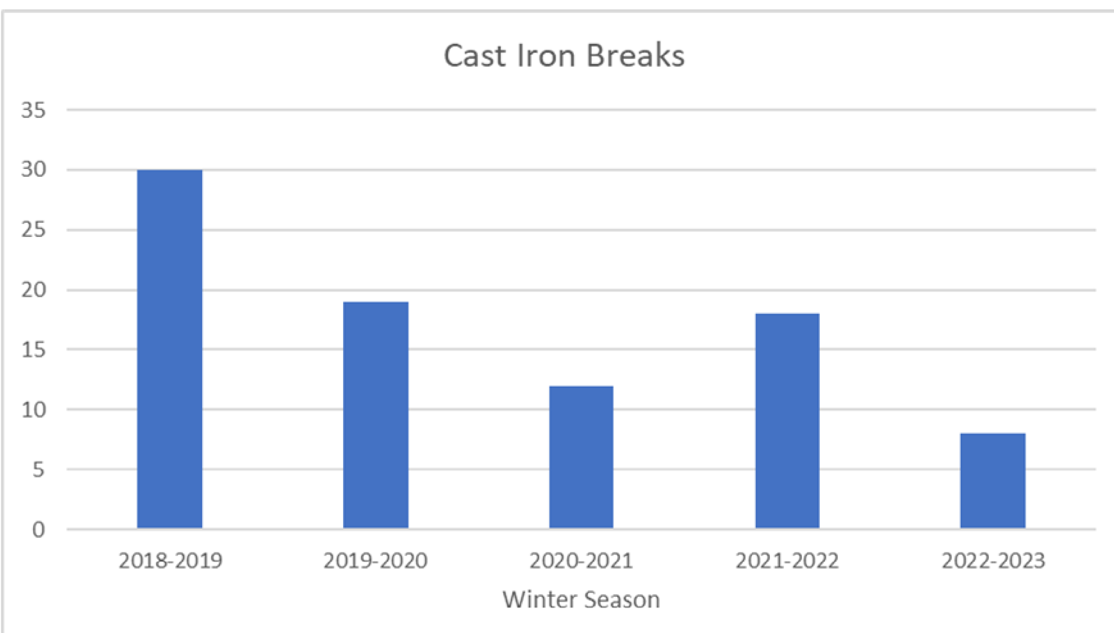
A. UGI Gas has seen a significant reduction in the number of leaks found on its system. This is directly attributable to its prioritization and aggressive replacement of leak-prone mains, services, and other assets. As Table 3 below demonstrates, since 2018, Class 'C' leak repairs have decreased by 29.4%, Class 'B' leak inventories have decreased by 36.5%, and Class 'A' leak inventories have decreased by 43.4%.

Table 3. Leak Inventories & Repairs

	Calendar Year 2018	Calendar Year 2023	Percent Change
C Leak Repairs	1,188	839	29.4% decrease
B Leak Inventory	285	181	36.5% decrease
A Leak Inventory	5,234	2,962	43.4% decrease

Figure 1 below shows the reduction in the number of cast iron breaks each winter season since the 2018-2019 season. There has been an overall 73% reduction in break frequency since the 2018-2019 season. The reduction helps demonstrate effectiveness of cast iron replacement activities.

Figure 1. Cast Iron Main Breaks (2018-2023)



Q. Please discuss UGI Gas's performance in the area of emergency response.

A. UGI Gas performs exceptionally well in the timely response to emergency notifications/calls. For the Fiscal Year ended September 30, 2024, 98.8% of the time, a first responder arrived on the premises within 45 minutes (or less) of receipt of an emergency call. UGI Gas utilizes a combination of shift coverage and on-call schedules to leverage internal field and supervisory resources to provide emergency response coverage 24-hours per day, 365 days per year. I also note that UGI Gas sets performance goals on a 45-minute response, which is more stringent than the benchmark response time as defined by the Commission's Safety Division.[5] Moreover, for Fiscal Year 2024, 99.9% of the time a UGI Gas first responder arrived onsite within one hour of the emergency call. This compares very favorably to the industry average. UGI Gas also had an average emergency dispatch time of only 3.2 minutes for Fiscal Year 2024, which is well below the 15-minute benchmark.

VI. SAFETY INITIATIVES

Q. What programs does UGI Gas have in place regarding employee, customer, and system safety?

A. Safety performance is a core value to UGI Gas. The Company's success depends on its employees' commitment and dedication to safety. Therefore, UGI Gas maintains a culture that drives employees to perform their day-to-day responsibilities with a high degree of

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[5] The Commission's Bureau of Audits issued a Management and Operations Audit Report of the Company in October 2019 (at Docket Nos. D-2018-3002234, D-2018-3002235 and D-2018-3002236), which stated:

> The PUC Gas Safety Division defines acceptable emergency dispatch and response times as 15 minutes and 60 minutes, respectively. However, UGI has established a more stringent 45-minute emergency response key performance indicator of 97.8%. (Audit Report, p. 41).

safety. UGI Gas has advanced several initiatives to further develop its safety culture and drive sustainable improvements in safety performance. As an example, in September 2021, UGI Gas implemented a robust telematics and in-cab driver coaching system for all drivers of Company vehicles and continues to enhance and develop its safe driving program through intentional supervisory coaching of "events" triggered by the system, as well as positive recognition of safe defensive driving maneuvers.

UGI Gas is also introducing a focus on High Energy Hazard Assessment and Energy Control in line with the Edison Electric Institute's Safety & Classification Learning Model, an industry-standard approach to categorizing safety learning opportunities to reduce potentially serious or fatal injuries. The UGI Safety team has been trained in use of the model for hazard assessment at crew visits and categorization of incidents or near misses. Employee training in the hazard recognition elements of the model began in October 2024 and will continue through FY2025.

Finally, as discussed previously, UGI Gas incorporates API RP 1173, which establishes a PSMS framework for corporations that operate hazardous liquids and gas pipelines under the U.S. Department of Transportation's jurisdiction. API RP 1173 provides a framework to reveal and manage risk, promotes a learning environment, and continuously improves pipeline safety and integrity. This continuous improvement effort and framework reduces hazards and prevents incidents. UGI Gas completed training in Fiscal Year 2023 and Fiscal Year 2024 of key personnel in root cause analysis to facilitate continuous improvement in both employee safety and pipeline and public safety.

Q. What other ongoing safety programs does the Company have?

A. Other ongoing safety measures and tools include Smith System driver training and a 24-hour Triage Nurse Hotline. The Company has also adopted multiple programs to enhance its safety protocols. One such program is the UGI "Making a Difference by Living Our Values" incentive program, which rewards employees who demonstrate positive safety behaviors, including, but not limited to, leading safety meetings, reporting safety issues, or participating in safety education. UGI has further implemented a "Near Miss/Good Catch" program, which seeks to proactively prevent safety incidents by learning from issues that had the potential for, but did not result in, damage or harm. In addition, the Company uses EcoOnline, a safety incident software, which facilitates incident management and data collection for various types of incidents and tracks those incidents through the investigation process. Moreover, the Company utilizes ISNetworld vendor safety software to qualify contractors and monitor their performance trends. ISNetworld collects safety information from these contractors and compares them against UGI Gas's established safety standards to make sure their safety performance is at a satisfactory level in order to perform work for the Company. ISNetworld conducts ongoing monitoring of the contractor's safety information and alerts UGI Gas if a contractor falls below the Company's minimum safety standards – either in UGI Gas's service territory or anywhere else in the country. This helps ensure that UGI Gas's contractors provide safe and reliable service to the Company's community and customers.

Q. What training initiatives is the Company undertaking?

A. The Company has advanced its offerings at its Learning Center and continues to enhance the training program abilities at the Learning Center. The Learning Center is used for all new hire and employee progression field training. It is also used for ongoing training and operator re-qualification for employees and contractors. Key enhancements in Fiscal Years 2023-2024 were the implementation of robust Emergency Response training exercises utilizing the Leak Town, where trainees respond to real but controlled gas leaks on underground and aboveground, indoor and outdoor leak scenarios under the supervision of instructors.

The Company's operator qualification and technical training team has completed reorganizing, revising, and reformatting the training curriculum to enhance learning through incorporation of additional hands-on practice elements and interaction afforded at the UGI Learning Center. In addition, UGI Gas has nearly completed aligning the evaluation requirements of the Company's operator qualification tasks with the American Society of Mechanical Engineers ("ASME") B31Q Standard and expects to be complete by June of 2025. When that process completes, the Company's evaluation requirements will align with the latest industry best practices.

VII. ENVIRONMENTAL PROGRAMS

A. ENVIRONMENTAL REMEDIATION PROGRAM

Q. Please discuss environmental management at UGI Gas.

A. The environmental group at UGI Gas is focused on three main activities: (1) the investigation and remediation of environmental impacts related to historical operations; (2)

environmental compliance activities, such as permitting and operational improvements; and (3) sustainability and methane reduction activities.

Q. Please describe the Company's investigation and remediation of environmental impacts related to historical operations.

A. From the mid-1800s through the mid-1900s, UGI Gas and its predecessors owned and operated a number of manufactured gas plants ("MGPs") that, prior to the general availability of natural gas, generated gas from other fuel stocks for residential, commercial, and industrial customer use. In Pennsylvania, this process generally used coal as a fuel stock. Some byproducts of this manufacturing process, including coal tars and other residues of the manufactured gas process, are today considered potentially hazardous substances under state and federal environmental laws.

Historically, UGI Gas operated its environmental remediation programs under three consent orders and agreements ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP"). UGI Gas's former utility companies, UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), were each parties to separate COAs with PADEP, and a UGI Gas COA was executed in 2016. Following UGI CPG and UGI PNG's merger into UGI Gas, on October 1, 2020, the three separate UGI COAs were consolidated into a single UGI Gas COA that covers the period through October 1, 2035. This COA obligates the Company to either meet an annual minimum environmental spend commitment of $5.35 million or achieve a minimum annual point total of 9,000 points,[6] with points being issued for the completion of various designated environmental tasks under the COA through October 1, 2035.

Q. What types of costs does UGI Gas incur with respect to addressing MGP site conditions?

A. UGI Gas incurs costs for site investigations, remediation, and site restoration as well as related PADEP oversight costs. Costs may also be incurred to obtain an environmental covenant at the site to prevent certain uses of the site, and costs associated with transferring the site to a third party (such as with a dedication for public use) once the site has been restored. Costs may also be incurred to purchase a property to secure access to investigate and remediate. Additionally, expert and legal costs are sometimes incurred in interactions with insurance carriers or other potentially responsible parties to ensure that UGI Gas's customers are only paying their equitable share of investigation and remediation costs. These costs may also be incurred to implement PADEP workplans if the Company faces opposition to the investigation or remediation of the site. Costs may also be incurred to recover compensation under historical insurance policies to offset the costs that would otherwise be recovered from customers.

Q. What is UGI Gas's projected spending on the MGP program?

A. UGI Gas has held the COA annual minimum spend of $5.35 million as the target projected spend for each year to meet the COA objectives, if minimum annual points cannot be

[6] The COA includes an "accounting system" with provisions to track progress with respect to the investigation, characterization, and remediation of the MGP properties. In any given fiscal year, the Company is required to achieve a minimum of 9,000 points, which demonstrates efforts and progress toward remediation, or exceed the minimum required spend of $5.35 million.

achieved. UGI Gas's average aggregate annual spending over the past three fiscal years is $5.429 million, as shown below in Table 4.

Table 4. Environmental Spent per Fiscal Year

Fiscal Year	Total
2022	$3,244,000
2023	$5,441,000
2024	$7,602,000
Average	$5,429,000

The three-year average amount is used in the calculation of the environmental adjustment shown in UGI Gas Exhibit A, Schedule D-8, as discussed in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement. No. 2).

Forecasted MGP activity costs are anticipated to be higher than the $5.35 million target per the COA and potentially higher than the three-year average of spend of $5.43 million in the next few years, as remediation activities are planned to address areas of impacted soils and groundwater that were identified from prior investigation activities and that are required to move the sites to closure under PADEP Act 2 protocols and COA requirements.

Q. Why does environmental spend vary from the minimum environmental spend set by the COA?

A. While the Company uses the COA minimum spend as a benchmark for environmental cost budgeting, actual costs may exceed the minimum in certain years due to PADEP requirements, varied levels of investigation and remediation activity to address MGP site program priorities, addressing public concerns, changing environmental standards, and site-specific issues such as sensitive habitat and concentration of contaminants. Investigation activities tend to involve lower costs than remediation activities, which have higher costs associated with the active removal or neutralization of impacted soil or groundwater. For example, the 2022 spend shown in Table 5 was lower due to being influenced by a heightened level of investigation activities and lower remediation activity, noting COA requirements were met in that year by completing tasks to achieve the minimum points. However, additional funds beyond the target of $5.35 million were spent in 2023 and 2024, when remediation activities at several sites were conducted.

Q. What is UGI Gas's goal for restoration of the MGP sites?

A. UGI Gas strives to restore each site for beneficial reuse that becomes an asset to the Company or the community. Because these MGP sites are located within the Company's existing service territory, restoration of the sites for beneficial reuse, whether in the form of use by the Company, urban redevelopment, or the creation of a new public space, directly benefits the customers and communities served by the Company.

B. EMISSIONS REDUCTIONS PROGRAMS

Q. How does UGI Gas quantify the environmental impact of its operations?

A. In addition to the environmental stewardship actions discussed in Mr. Bell's testimony (*e.g.*, oil to gas conversion, energy efficiency and conservation, etc.) (UGI Gas Statement No. 1) that reduce emissions, UGI Gas was a partner in the United States Environmental Protection Agency's ("EPA") voluntary Natural Gas STAR Partnership Program from inception until it was sunset by the agency in 2022. The Natural Gas STAR Partnership provided a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities.

On March 30, 2016, UGI Gas joined with 32 other natural gas utilities to launch the EPA's Natural Gas Methane Challenge Partnership. As a founding member of the Methane Challenge Partnership, UGI Gas has committed to tracking and achieving certain emissions reductions. Participation in this voluntary program includes a commitment to replace infrastructure to achieve a reduction in fugitive methane emissions. UGI Gas reduced fugitive methane emissions associated with pipeline mains and services by 9.8% in 2021-2022 as documented in its most recent program filing. Note that the EPA has also chosen to sunset the Natural Gas Methane Challenge Partnership at the end of 2024 due to updates to the regulatory framework advanced to reduce methane emissions.

In other activity, UGI Gas continues to add Compressed Natural Gas ("CNG") vehicles to its fleet. Currently, over 25% of the fleet is made up of CNG-powered vehicles, with plans to increase the number to approximately 25% by the end of Fiscal Year 2026. Three of the Company's operations locations have CNG filling stations (Archbald, Wilkes-Barre, and Bethlehem), and UGI Gas will install a new station near its Middletown office by the end of the FPFTY. In other locations, utilizing nearby commercial CNG fueling stations makes it feasible to convert fleets to CNG in smaller operations centers. Since 2016, it is estimated that the conversion of gasoline and diesel fueled fleet vehicles to CNG has reduced Company emissions by almost 1,000 metric tons of carbon dioxide equivalent ("$MTCO_2e$").

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT CRB-1

CHRISTOPHER R. BROWN

VICE PRESIDENT – OPERATIONS

UGI Utilities, Inc.

Vice President – Operations	November 2023 - Present
Vice President – Finance and Chief Financial Officer	January 2023 – November 2023
Vice President and General Manager, Rates and Supply (Denver, Pa.)	May 2019 – January 2023
Sr. Director- Operations South Region (Reading, Pa.)	July 2015- May 2019
Manager - Operations (Reading, Pa.)	July 2013 – July 2015
Director- Central Services (Reading, Pa.)	October 2010 – July 2013
Manager – Strategy Processes and Implementation (Reading, Pa.)	February 2010 – October 2010
Manager – Customer Accounting Services (Reading, Pa.)	May 2009 – February 2010
Marketing Manager – East Region (Allentown, Pa.)	April 2008 – May 2009

Amerigas Propane, Inc.

Market Manager (Stroudsburg, Pa.)	June 2005 to April 2008

UGI Utilities, Inc.

Supervisor – Gas Supply and Transportation (Reading, Pa.)	September 2003 – June 2005
Distribution Superintendent (Harrisburg, Pa.)	September 2001 – September 2003
Staff Engineer – Commercial Marketing (Reading, Pa.)	September 1999 – September 2001
New Business Engineer (Allentown, Pa.)	June 1997 – September 1999

Education

MBA, Lebanon Valley College, Annville, Pa.
BS, Civil Engineering, Lehigh University, Bethlehem, Pa.

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-00050539	UGI Utilities Inc. - Annual 1307(f) Filing
Docket No. C-2015-2516051	Centre Park Historic District v. UGI Utilities, Inc.
Docket No. C-2016-2530475	City of Reading v. UGI Utilities, Inc.
Docket No. R-2019-3015162	UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding
Docket No. R-2021-3023618	UGI Utilities, Inc. Electric Division - Base Rate Case Proceeding
Docket No. R-2021-3030218	UGI Utilities, Inc. Gas Division – Base Rate Case Proceeding
Docket No. R-2022-3037368	UGI Utilities, Inc. Electric Division – Base Rate Case Proceeding

UGI GAS STATEMENT NO. 10

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed: **Cost of Service**
Revenue Allocation
Rate Design

Dated: January 27, 2025

Table of Contents

Glossary of Acronyms

A&G	Administrative and General
ACOSS	Allocated Cost of Service Study
Atrium	Atrium Economics, LLC
CAP	Customer Assistance Program
Commission	Pennsylvania Public Utility Commission
DSIC	Distribution System Improvement Charge
FERC	Federal Energy Regulatory Commission
FPFTY	Fully Projected Future Test Year
LIHEAP	Low-Income Home Energy Assistance Program
LIURP	Low-Income Usage Reduction Program
NARUC	National Association of Regulatory Utility Commissioners
O&M	Operating and Maintenance
Rate DS	Delivery Service
Rate IS	Interruptible Service
Rate LFD	Large Firm Delivery Service
Rate N	General Service – Non-Residential & Non-Residential Transportation
Rate R	General Service – Residential & Residential Transportation
Rate XD Firm	Extended Large Firm Delivery Service
UGI Gas	UGI Utilities, Inc. – Gas Division

I. WITNESS IDENTIFICATION AND BACKGROUND

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of UGI Utilities, Inc. – Gas Division's ("UGI Gas" or the "Company").

Q. What is the purpose of your testimony in this proceeding?

A. I prepared and am sponsoring UGI Gas's fully allocated cost of service study ("ACOSS"), which is found in UGI Gas Exhibit D. The ACOSS determines the embedded costs of serving UGI Gas's distribution customers associated with the Pennsylvania Public Utility Commission ("Commission") jurisdiction. I also support the apportionment, or allocation, of the class revenue increase and the Company's rate design proposal.

Q. Please describe your educational background and professional experience.

A. UGI Gas Exhibit JDT-1 contains background information summarizing my education, presentation of expert testimony, and other industry-related activities.

Q. Please summarize the content of your testimony.

My testimony consists of this introduction section (I) and the following five additional sections: (II) Purpose and Principles of Cost Allocation, (III) UGI Gas's Allocated Cost of Service Study, (IV) Principles of Sound Rate Design, (V) UGI Gas's Class Revenues, and (VI) UGI Gas's Rate Design.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Book IX, labeled as UGI Gas Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. I also am sponsoring portions of Book I and Book II, Section 53.53 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation.

II. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. What is the general purpose and use of an ACOSS in regulatory proceedings?

A. The purpose of an ACOSS is to allocate the gas distribution utility's overall fully projected future test year ("FPFTY") costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. An ACOSS represents an analysis of which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop the ACOSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes, or the cost of providing multiple products to the same rate class, use the same facilities and the use by one rate class precludes the use by another rate class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, the ACOSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and commodity developed in the ACOSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Is the preparation of an ACOSS an exact science?

A. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. The allocation of costs using an ACOSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers, with such return on being reflective of a fair rate of return. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. Is there a guiding principle that supports the appropriate allocation of costs?

A. Yes, a fundamental foundational principle, cost causation, should be followed to produce accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs, so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How do you establish the cost and utility service relationships?

A. An important element in the selection and development of a reasonable ACOSS methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. To accomplish this, I reviewed UGI Gas's expense and plant accounts, operational data, usage information, and conducted interviews with UGI Gas employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for the utility's plant and expense elements.

Q. What are the steps to performing an ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the basis to conduct an ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Gas's primary functional cost categories associated with natural gas distribution services include gas supply, transmission, distribution, and customer. Indirect costs that support these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Q. Please describe cost classification.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the gas distribution system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the ACOSS as: (1) customer costs; (2) demand costs; and (3) commodity costs, respectively.

Q. Please describe the types of costs contain in the customer, demand, and commodity costs categories.

A. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to UGI Gas's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by UGI Gas for its customers.

Q. Please describe the cost allocation process.

A. The final step is the allocation of each functionalized and classified cost element to the individual rate class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors. From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service. Notably, UGI Gas has performed direct assignment analysis of its most competitive negotiated rate customers who receive service under Rate XD, and those direct assignment results are reflected in the ACOSS presented in UGI Gas Exhibit D.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors that can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting UGI Gas's ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study is conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. How does the availability of data influence an ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

III. UGI GAS'S ALLOCATED COST OF SERVICE STUDY

Q. Please describe the Atrium Model used in conducting the ACOSS filed in this proceeding.

A. UGI Gas has selected the Atrium excel based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. Atrium developed the Atrium ACOSS Model on a proprietary basis for its consulting engagements and has been used in multiple jurisdictions. This is similar to the Atrium ACOSS Model that UGI Utilities, Inc. – Electric Division presented and that I sponsored in its base rate cases at Dockets No. R-2021-3023618 and No. R-2022-3037368.

Q. Please describe the process of performing UGI Gas's ACOSS presented in this filing.

A. The detailed process description of UGI Gas's ACOSS analysis is presented in Exhibit D, providing a full scope of the process including the development of allocation factors that support various cost of service studies presented in this proceeding as discussed below.

Q. Please discuss the content of Exhibit D?

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(1) and, in particular, Exhibit A - Gas Utilities, by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(1), Exhibit A. The studies contained in UGI Gas Exhibit D are based on costs and operating conditions for the FPFTY ending September 30, 2026.

Exhibit D consists of three sections detailing the process of developing the ACOSS. Section I – Introduction includes an introduction, the general purpose and process of the ACOSS, as well as an overview of the excel-based fully functional ACOSS model presented in this proceeding. Section II – UGI Gas's Cost of Service Procedures presents the ACOSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section II.3) describes all internal and external allocation factors and the allocation processes used in the ACOSS. The last section, Section III – UGI Gas's Cost of Service Results depicts the results of the ACOSS, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the content and schedules included in Exhibit D.

A. Exhibit D contains a narrative description of the ACOSS procedures, provides details on the allocation factors, and contains the following Schedules:

- Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates
- Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 3 - Cost of Service Allocation Study Detail by Account
- Schedule 4 - Account Balances and Allocation Methods
- Schedule 5 - External Allocation Factors
- Schedule 6 - Internal Allocation Factors Summary

Q. What was the source of the cost data analyzed in UGI Gas's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (*i.e.*, total revenue requirement) and schedules contained in this general rate case filing for the FPFTY ending September 30, 2026. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are UGI Gas's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Gas's ACOSS, I included six rate classes:

- Rate R - General Service – Residential & Residential Transportation
- Rate N - General Service – Non-Residential & Non-Residential Transportation
- Rate DS - Delivery Service
- Rate LFD - Large Firm Delivery Service
- Rate XD Firm - Extended Large Firm Delivery Service
- Rate IS - Interruptible Service

Q. How did you classify and allocate the cost of distribution mains?

I classified distribution mains as 100% demand related and allocated their costs in two steps. First, a portion of the costs was directly assigned to Rate XD Firm based on an analysis provided by the Company. Second, I allocated the remaining balance using the Average and Excess ("A&E") method.

Q. Please describe the methodology used for the costs directly assigned to the XD customers.

A. For each customer, a distribution system analysis is performed to determine which assets (including footage, diameter, material type, and vintage year) of the distribution system are utilized to physically serve the customer. Using the Company's plant records, the costs and footage for these assets are summarized based on the footage assigned to the customer as a percentage of the total footage for that asset. A portion of this cost is allocated to that customer based on the customer's throughput on that asset as a percent of the asset total. The calculated costs for all assets assigned to that customer are summed to determine the directly allocated costs for that customer.

Q. Please describe the A&E method.

A. The A&E method allocates costs based on a combination of average usage and peak usage levels. This method is used to allocate costs on both the consistent usage (average demand), and the additional capacity needed during peak times (excess demand). The average demand is determined by the average daily throughput volumes per customer class. The excess demand represents the additional capacity needed to meet the peak demand or maximum usage levels for each customer class. These two factors are weighted based on the system load factor, which is the ratio of average demand to peak demand for the entire system. This factor determines the proportion of costs attributed to average daily usage versus peak capacity requirements.

Q. Can you explain the system load factor and its significance in this method?

A. The system load factor is calculated as follows:

$$\text{Load Factor} = \text{Average Daily Throughput} \div \text{Peak Day Demand}$$

It indicates the efficiency of the system's utilization. A higher load factor suggests that demand is relatively stable, reducing the need for excess capacity. This metric helps balance the cost allocation between average usage and peak demand. UGI Gas's firm service load factor for the FPFTY is 41.27%, which is the system load factor excluding interruptible load. Therefore, the allocation assigns 41.27% of the costs to average daily usage and 58.73% to peak demand.

Q. Why is the interruptible load excluded from the load factor calculations?

A. Interruptible load is excluded from the load factor calculations because it does not contribute to the system's peak day demand, which is a critical driver of infrastructure. In addition, interruptible customers are not assigned any excess load. Interruptible customers agree to reduce or halt their gas usage during periods of high demand, meaning they do not place the same capacity requirements on the distribution system as firm customers. Including interruptible load would misrepresent the true cost drivers and unfairly allocate costs to customers who do not rely on guaranteed peak capacity.

Q. Has the A&E method been approved by the Commission?

A. Yes. The A&E method was approved by the Commission in the last two fully litigated gas rate cases in Pennsylvania. Specifically, the A&E method was upheld in the orders at Docket Nos. R-2020-3018929 and R-2020-3018835, involving rate cases for PECO Energy Company and Columbia Gas of Pennsylvania, respectively.

Q. Did you consider other classification or allocation methods?

A. Yes. I considered the customer/demand classification method and the Peak and Average ("P&A") allocation method. However, the Commission has not traditionally recognized the customer component of gas mains, which makes the customer/demand classification method less viable.[1]

The P&A allocation method has also been evaluated for use in past Pennsylvania rate cases and applies a fixed 50/50 weighting instead of relying on the system load factor.

Q. How do the allocation results differ between the A&E method and the P&A method for UGI Gas in this case?

A. The allocation results for each method are presented below in Table 1. The A&E method allocates a higher percentage of costs to Rate R (46.5% vs. 44.8%) and Rate N (32.0% vs. 29.4%), reflecting its reliance on the system load factor and its balanced approach to cost distribution. On the other hand, the P&A method allocates a higher percentage of costs to Rate LFD (14.7% vs. 11.3%) and Interruptible (4.4% vs. 3.6%), due to its 50/50 weighting of average demand within the peak portion. These differences illustrate how the P&A method allocates more costs to higher-load customers than the A&E method.

[1] *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order entered February 19, 2021), p. 217.

Table 1 – Comparison of Mains Allocators of the Company's ACOSS

	Rate R	Rate N	Rate DS	Rate LFD	Interruptible
A&E	46.5%	32.0%	6.6%	11.3%	3.6%
P&A	44.8%	29.4%	6.7%	14.7%	4.4%

Q. Does UGI Gas's ACOSS include gas commodity costs?

A. Yes. The gas costs reflected in the ACOSS correspond to gas cost revenues that have a neutral impact on the study's results, resulting in a net-zero effect.

Q. Please summarize the results of the Company's ACOSS.

A. Table 2 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 1 of Book IX, UGI Gas Exhibit D. The ACOSS shows an overall revenue requirement of $1,251.3 million and a resulting deficiency of $110.4 million. The revenue deficiency/excess for each rate class shows revenue increases or decreases necessary to get the classes to their cost to serve.

Table 2 - Summary Results of the Company's ACOSS ($000)[2]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
Rate R	$ 723,552	$ 829,647	$ (106,095)	14.7%	5.0%	0.87	0.96
Rate N	248,001	275,116	(27,115)	10.9%	6.4%	0.90	0.99
Rate DS	35,191	34,482	710	-2.0%	9.1%	1.02	1.12
Rate LFD	55,628	51,559	4,069	-7.3%	10.0%	1.08	1.18
Rate XD Firm	39,193	28,840	10,353	-26.4%	15.5%	1.32	1.45
Rate IS	24,486	16,803	7,683	-31.4%	16.1%	1.45	1.59
Total Base	**1,126,051**	**1,236,446**	**(110,395)**	**9.8%**	**6.5%**	**0.91**	**1.00**
Other Revenues	14,836	14,836	-				
Total Company	**1,140,887**	**1,251,282**	**(110,395)**				

The ACOSS shows that Rate R and Rate N classes are being charged rates that recover less than their indicated costs of service, whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. In other words, to set each classes' revenues equal to their cost to serve indicated in the ACOSS, Rate R and Rate N would require an increase in revenues, while all other classes would require a decrease. Additionally, Table 2 provides helpful insights into UGI Gas's class financial metrics, such as the current Rate of Return and corresponding Relative Rate of Return and Current Revenue to Cost Ratio with the corresponding Parity Ratio.

Q. Have you prepared more detailed reports of UGI Gas's ACOSS results?

A. Yes, additional details are included in Exhibit D. Schedule 4 "Account Balances and Allocation Methods" of Exhibit D includes revenue requirement information by FERC account provided by UGI Gas and shows assigned functions, categories, and allocation factors. Schedule 3 "Cost of Service Allocation Study Detail by Account" of Exhibit D

[2] See Exhibit D, Schedule 1, lines 13, 52, 57, 24, 26, and 27.
Percent Change = Class Revenue (Deficiency)/Sufficiency ÷ Current Revenues

presents the resulting allocations by customer class of UGI Gas's proposed revenue requirement based on the results of the computations included in the ACOSS.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles help inform the apportionment of revenues (i.e., revenue targets for each rate class) and the rate design of rate components within each rate class. They include:

1. Cost of Service;
2. Efficiency;
3. Value of Service;
4. Stability/Gradualism;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3] Each of these principles plays an important role in analyzing the rate design proposals of UGI Gas. In addition, these principles are consistent with Pennsylvania practice and precedent,

[3] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

including the *Lloyd* decision,[4] where the Commonwealth Court indicated that cost of service is the "polestar" of ratemaking but that other factors, including those listed above, can be considered as well.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. There are tensions between the cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between the value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and

[4] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

V. <u>UGI GAS'S CLASS REVENUES</u>

Q. Please describe the approach generally followed in allocating UGI Gas's proposed revenue increase of $110.4 million to its various rate classes.

A. To reflect the results of the class cost-of-service study, the Company is proposing to move all rate classes closer to the overall system rate of return and, as a result, reduce the current subsidies occurring between classes. This movement of classes towards the overall system rate of return is consistent with regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement of that case.

Q. Please describe the proposed approach to apportion UGI Gas's proposed revenue increase to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The benchmark option evaluated under UGI Gas's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. This is shown above in Table 2 where the changes in each classes revenues would be set to their deficiency or surplus. It was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue, given the large increase required to move some classes to parity. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time while addressing issues of gradualism. The decision was made to provide rate decreases to competitively negotiated classes XD and IS equivalent to incorporating the present Distribution System Improvement Charge ("DSIC") rider into base rates. These decrease amounts have then been effectively constrained within the Company's "contract customer" group (DS, LFD, XD, IS) by increases being allocated to classes DS and LFD. Rate R and Rate N would receive increases to move them closer to parity, equivalent to 1.25 the system increase. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the reduction in the subsidies occurring between classes. With these considerations, the Company is proposing the revenue changes shown in the table below.

Table 3 – Proposed Class Revenue Apportionment
Base Distribution Margin ($000)[5]

Customer Classes	Current Revenues	Proposed Revenues	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return	Proposed Revenue to Cost Ratio
Rate R	$ 723,552	$ 806,648	$ (83,096)	11.5%	7.1%	0.97
Rate N	248,001	$ 275,342	(27,341)	11.0%	7.9%	1.00
Rate DS	35,191	$ 36,291	(1,100)	3.1%	8.9%	1.05
Rate LFD	55,628	$ 56,729	(1,101)	2.0%	9.5%	1.10
Rate XD Firm	39,193	$ 38,083	1,110	-2.8%	13.6%	1.29
Rate IS	24,486	23,353	1,133	-4.6%	13.9%	1.39
Total Base	**$ 1,126,051**	**$ 1,236,446**	**$ (110,395)**	**9.8%**	**7.9%**	**1.00**

[5] See Exhibit D, Schedule 1, lines 10, 52, 58, 61, 70, and 72.

Q. To what degree does the Company's proposed revenue apportionment move the classes toward their cost of service?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes and moves classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable such that class revenues and rates are closer to the indicated cost of service for each rate class.

Table 4 below compares the current and proposed rate of returns and parity ratios. The Company's proposal moves the return for all rate classes closer to the Company's proposed return. Likewise, parity ratios move closer to the desired 1.0 level.

Table 4- Comparison of Relative Rate of Return by Rate Class
Base Distribution Margin ($000)[6]

Customer Classes	Current Revenues	Proposed Revenues	Current Return	Proposed Return	Current Parity Ratio	Proposed Parity Ratio
Rate R	$ 723,552	$ 806,648	5.0%	7.1%	0.96	0.97
Rate N	$ 248,001	$ 275,342	6.4%	7.9%	0.99	1.00
Rate DS	$ 35,191	$ 36,291	9.1%	8.9%	1.12	1.05
Rate LFD	$ 55,628	$ 56,729	10.0%	9.5%	1.18	1.10
Rate XD Firm	$ 39,193	$ 38,083	15.5%	13.6%	1.45	1.29
Rate IS	$ 24,486	$ 23,353	16.1%	13.9%	1.59	1.39
Total Base	**$ 1,126,051**	**$ 1,236,446**	**6.5%**	**7.9%**	**1.00**	**1.00**

Q. To what degree does the Company's proposed revenue apportionment decrease the existing subsidies between rate classes?

A. Table 5 below summarizes the current and proposed subsidies and the reduction in all customer classes' subsidies resulting from the Company's proposed revenue apportionment.

[6] Exhibit D, Schedule 1, lines 10, 52, 24, 70, 27, and 73.

Table 5 - Comparison of Present and Proposed Subsidies ($000)[7]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Rate R	$ (33,713)	$ (22,999)	$ 10,714
Rate N	(832)	226	1,058
Rate DS	4,491	1,810	2,682
Rate LFD	9,693	5,170	4,523
Rate XD Firm	11,791	9,243	2,548
Rate IS	8,569	6,550	2,019
Total Company	$ -	$ -	$ -

VI. <u>UGI GAS'S RATE DESIGN</u>

Q. Please summarize the rate design changes UGI Gas has proposed in this rate proceeding.

A. In general, UGI Gas's rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide natural gas distribution service to those customers. UGI Gas has proposed the following rate design changes to its current tariff schedules:

- Rate R – Increase in the Monthly Customer Charge from $15.00 to $19.95, with the remaining proposed increase to be recovered in the Volumetric Charge.
- Rate N – Increase in the Monthly Customer Charge from $27.38 to $36.42, with the remaining proposed increase to be recovered in the Volumetric Charge.
- Rate DS – Increase in the Monthly Customer Charge from $260 to $300, with the remaining proposed increase to be recovered in the Volumetric Charge, with no difference between the former South & Central District and the former North District.

[7] See Exhibit D, Schedule 1, lines 35 and 63. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

- Rate LFD – Increase in the Demand Charge from $5.9965 per Mcf to $7.6956 per Mcf.
- Rate XD Firm – Decrease equivalent to the DSIC rider amount.
- Rate IS – Decrease equivalent to the DSIC rider amount.

Q. What is the impact on customers in the former North District under Rate DS from applying the same rates as those in the former South and Central Districts?

A. The overall impact on customers in the former North District under Rate DS, as a result of applying the same rates as those in the former South and Central Districts, is an increase of 17.9%. This increase is approximately 1.24 times the system-wide average increase of 14.4%. This increase reflects the adjustment necessary to align the former North District rates with the existing structure in the former South and Central Districts, ensuring consistency across the system.

Q. Has the Company prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?

A. Yes. UGI Gas Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A. Epler, presents a detailed comparison of present and proposed revenues for each of UGI Gas's rate classes.

Q. How does the ACOSS support the proposed increases to customer charges?

A. Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. Table 6 below provides the information related to the current and proposed customer charges for Rates R, N, and DS, compared to the customer related unit cost – per customer, per month.

Table 6 - Customer Charge Current, Proposed, and ACOSS Unit Cost Results ($)[8]

Customer Classes	Current Basic Facilities Charge	Proposed Basic Facilities Charge	Customer Related Unit Cost	Demand and Customer Related Unit Cost
Rate R	15.00	19.95	51.19	76.07
Rate N	27.38	36.42	68.13	221.76
Rate DS	260.00	300.00	537.96	2,174.94

As seen in the above table, the proposed increases in customer charges are still under the customer related unit cost identified in the ACOSS. These include the customer portion of distribution facilities and customer service and billing costs.

Q. Can you please discuss the results in Table 6 above within the context of the Company's proposed customer charges and past Commission precedent?

A. Yes, past Commission precedent defines customer-related costs for inclusion in a customer charge as costs associated with meters and services and related O&M expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The Company is proposing a Rate R customer charge of $19.95, which is below the $51.19 within Table 6

[8] See Exhibit D, Schedule 2, lines 118 and 119.

above, and represents meter reading, customer service, and billing and collection expenses. These are all costs historically allowed by the Commission in a customer charge. Taking into consideration past precedent in Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company is proposing to move the Rate R customer charge to $19.95. Similarly, the Company is proposing customer charge increases to Rate N and Rate DS that are still below the customer related unit cost for these rates.

Q. Why are setting customer charges more in alignment with the fixed cost of service an important outcome of ratemaking?

A. These proposed customer charges help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood, convey more appropriate price signals with respect to recovery of fixed utility costs, benefit low-income customers that have higher than average use, and are not regressive in application to low-income customers who may have little control over their use of energy and are negatively impacted when recovering more costs in volumetric charges.

Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric block prices, which has the effect of causing some customers to pay too much while others pay too little. The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether natural gas is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure the Company's recovery of a greater portion of its fixed costs of providing service. Inasmuch as costs are not related to usage, they should be recovered, to the extent possible, through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers easily recognize fixed cost charges and are used to these pricing structures in their everyday lives. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is cold, and conversely should not pay less when the weather is warm.

Q. Please expand on why an increase in the Rate R customer charge would benefit low-income customers.

A. There is a common misconception that low-income customers are low-usage customers. This is not a correct characterization of low-income customers who are indeed higher-use customers. As recorded in the Company's Universal Service Program effective December 1, 2024, the average use for a customer in the Customer Assistance Program ("CAP") is

113.6 Mcf/year.[9] This is almost 30% higher than the average of other Company's residential customers use of 88.4 Mcf/year.

Also, all else equal, higher customer charges necessitate lower variable charges. The collection of costs through fixed or volumetric charges is only the means of collecting the revenue to cover costs for a specific customer class. The amount of total revenue does not change. Higher usage customers pay more when more fixed customer costs are embedded in the volumetric rates. This creates a social equity concern, as customers who can afford to reduce their usage through energy efficiency investments can decrease their bills by making such investments, while those customers who cannot afford to make energy efficiency investments will see increases in their bills. Examples of those who could possibly afford to reduce their usage include higher-income households who can undertake more expensive energy efficiency measures or through a living situation such as a single individual versus a family with infant children.

Further, recovering fixed costs in volumetric charges places regressive burdens on low-income households who have to make decisions to reduce their gas usage that impacts their quality of life. While some environmental advocates may prefer that households stop using natural gas altogether, families still use gas for basic human needs such as keeping themselves warm and to cook and care for themselves.

[9] UGI Gas, Docket No. R- 2024-3048828; Purchased Gas Cost Compliance Filing Including Quarterly Adjustment; Supplement No. 54 to Tariff UGI Gas - Pa. P.U.C. No. 7 and Pa. P.U.C. No. 7S; Effective December 1, 2024, Supporting Documentation Schedule B.

Lastly, considerations relating to the intersection of income and rate design would be amiss if they did not include discussions relating to UGI Gas's low-income programs. UGI Gas offers a continuum of low-income targeted programs, beyond CAP, including Low-Income Home Energy Assistance Program ("LIHEAP"), Low-Income Usage Reduction Program ("LIURP"), and weatherization assistance. There is no reason to send the wrong price signal to all customers when the impacts on low-income customers are mixed (i.e., their ability to respond to higher variable charges, the lower quality of living they may choose to respond to higher variable charges, and the fact that low-income customers that use higher than average will disproportionately be impacted by higher variable charges) and when there are robust programs in place that target bill and weatherization assistance for low-income customers.

Q. Have you conducted an analysis of the difference between the current $15.00 monthly residential customer charge and the proposed $19.95 a month charge on low-income customers?

A. Yes. Table 7 compares the amount a low-income customer with an average usage of 113.6 Mcf/year would pay between the customer charge and the volumetric charge under the Company's proposal (Scenario A) of increasing the monthly customer charge to $19.95, and Scenario B, which keeps the monthly customer charge unchanged at $15.00.

Table 7 – Comparison of Annual Charges for Average CAP Customer[10]

Average CAP Customer	Scenario A	Scenario B	B - A	% change
Customer Charges	$ 239.40	$ 180.00	$ (59.40)	-33.0%
Distribution Charges	727.93	807.04	$ 79.11	9.8%
Total Annual Charges	**$ 967.33**	**$ 987.04**	$ 19.71	2.0%

The comparison shows that while the Company's proposal increases the annual customer charges by $59.40 or 33%, the increase is more than offset by the $79.11 or 9.8% lower distribution charges. In other words, by not changing the current customer charge, customers ultimately face higher overall costs because of the substantial increase in distribution charges. This suggests that any policy or pricing adjustment leading to keeping the customer charge unchanged would shift more costs to the distribution component, increasing the financial burden on low-income customers, as much as 2%, over the year. As previously stated, a volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the utility's system; and (4) needlessly inflate bills in the winter months. The important policy point in this discussion is that it makes no economic sense to send the wrong economic price signals to all customers in order to supposedly benefit a small

[10] Scenario A uses a monthly customer charge of $19.95 and distribution charges of $6.4078/Mcf, as proposed by the Company. Scenario B uses the current monthly customer charge of $15.00 and distribution charges of $7.1042/Mcf, which would be necessary to recover Rate R's proposed revenue.

subset of low-income customers. It is far more efficient to address the issues of low-income customers directly through programs and assistance, such as the Company's CAP.

VII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Gas's ACOSS, class revenues, and rate design.

A. My conclusions and recommendations are as follows:

- The Commission should accept the results of the Company's ACOSS as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system.
- The Commission should accept the results from the Company's ACOSS as a guide to evaluate and set UGI Gas's class revenues and rate design in this proceeding.
- The Commission should accept the Company's proposed apportionment of revenues to its rate classes because it reasonably balances the various criteria that the Company considered in the revenue apportionment process and moves classes towards their cost to serve.
- The Commission should approve the rate design proposed by the Company because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6)

recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JDT-1

John D. Taylor

MANAGING PARTNER

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

- California Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.

- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the development of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

TRANSACTION EXPERIENCE

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

FINANCIAL ANALYSIS AND MARKET RESEARCH

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost-of-service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.