

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 – JILL E. WALTER
UGI GAS STATEMENT NO. 4 – VIVIAN K. RESSLER
UGI GAS STATEMENT NO. 5 – AMY M. KELLER
UGI GAS STATEMENT NO. 6 – JOHN F. WIEDMAYER**

**UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63**

DOCKET NO. R-2025-3059523

Issued: January 28, 2026

Effective: March 29, 2026

UGI GAS STATEMENT NO. 1

HANS G. BELL

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

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**

Dated: January 28, 2026

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q. Please state your name and business address.**

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

4
5 **Q. By whom and in what capacity are you employed?**

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

11
12 **Q. Please briefly describe your responsibilities in that capacity.**

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

16
17 **Q. What is your educational and professional background?**

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

19
20 **Q. Have you testified previously before this Commission?**

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

1 **II. PURPOSE OF TESTIMONY AND RATE FILING OVERVIEW**

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

3 A. My testimony will present an overview of the rate filing, including a brief explanation of
4 the reasons for rate relief and an outline of the testimony of each witness in this proceeding.
5 I will also address UGI’s efforts to manage the affordability of service to customers with
6 the need to continue to undertake critical safety improvements on its distribution system.

7
8 **Q. Are you sponsoring any exhibits in this proceeding?**

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

12
13 **Q. Please identify the other witnesses providing direct testimony on behalf of UGI Gas**
14 **in this proceeding and the subject matter of their testimony.**

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

17 **Tracy A. Hazenstab** (UGI Gas Statement No. 2) holds the position of Sr. Manager –
18 Utility Rates for UGI Utilities, Inc. She addresses operating revenues and expenses and
19 the revenue requirement model supporting the Company’s proposed rate increase, UGI Gas
20 Exhibit A (Fully Projected). Ms. Hazenstab also sponsors the revenue requirement models
21 for the future and historic periods, UGI Gas Exhibit A (Future) and UGI Gas Exhibit A
22 (Historic), respectively.

1 **Jill W. Walter** (UGI Gas Statement No. 3) holds the position of Director Operations –
2 South Region at UGI Gas. Ms. Walter’s testimony addresses UGI Gas’s operations and
3 natural gas distribution system. In addition, Ms. Walter discusses UGI Gas’s Long-Term
4 Infrastructure Improvement Plan (“LTIIIP”), and the impact of the LTIIIP and other
5 initiatives on system performance, safety, and reliability, including an update on the
6 Company’s methane detection pilot that was agreed to in settlement of the 2025 Gas Base
7 Rate Case at Docket No. R-2024-3052716. Also, Ms. Walter addresses UGI Gas’s efforts
8 and future plans to investigate and, where necessary, remediate sites in Pennsylvania where
9 UGI Gas or corporate predecessors once owned and/or operated manufactured gas plants
10 in connection with gas utility operations.

11
12 **Vivian K. Ressler** (UGI Gas Statement No. 4) holds the position of Director – Utility
13 Financial Planning & Analysis (“FP&A”) at UGI. Ms. Ressler addresses the budgeting
14 process and certain operating expense adjustments, as well as the Company’s accounting
15 for information technology costs.

16
17 **Amy M. Keller** (UGI Gas Statement No. 5) holds the position of Sr. Manager – Regulatory
18 and Plant Accounting at UGI. Ms. Keller explains UGI Gas’s accounting processes used
19 to develop the Company’s actual book accounting results, which are the basis for the
20 Historic Test Year (“HTY”) ended September 30, 2025. Ms. Keller also presents UGI
21 Gas’s rate base claim for the HTY, Future Test Year (“FTY”), and Fully Projected Future
22 Test Year (“FPFTY”). Ms. Keller further addresses certain operating expense adjustments.

1 **John F. Wiedmayer** (UGI Gas Statement No. 6) holds the position of Senior Project
2 Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer
3 developed and supports UGI Gas’s claim for annual depreciation expense, and the
4 accumulated depreciation reserve. His studies are presented in UGI Gas Exhibit C (Fully
5 Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic).

6
7 **Vicky A. Schappell** (UGI Gas Statement No. 7) holds the position of Sr. Manager, Capital
8 Planning for UGI Gas. Ms. Schappell addresses capital expenditures and capital planning,
9 including the planned plant in service expenditures for the FTY and FPFTY.

10
11 **Dylan W. D’Ascendis** (UGI Gas Statement No. 8) holds the role of Partner at ScottMadden
12 Management Consultants. Mr. D’Ascendis presents expert testimony supporting the
13 Company’s claimed capital structure, cost of debt, cost of common equity, and overall fair
14 rate of return. Schedules and workpapers supporting Mr. D’Ascendis’s findings are set
15 forth in UGI Gas Exhibit B (Rate of Return).

16
17 **Darin T. Espigh** (UGI Gas Statement No. 9) holds the position of Sr. Manager – Natural
18 Gas Tax Accounting. Mr. Espigh addresses various tax issues, including the Company’s
19 claim for federal and state income taxes, taxes other than income taxes, the calculation of
20 the accumulated deferred income taxes (“ADIT”) offset to rate base, and the repairs
21 allowance.

22
23 **Sherry A. Epler** (UGI Gas Statement No. 10) holds the position of Senior Manager Tariff
24 and Supplier Administration for UGI. Ms. Epler’s testimony addresses the development

1 of the Company’s HTY, FTY and FPFTY test year sales and revenues. In addition, Ms.
2 Epler addresses several proposed tariff updates. Ms. Epler sponsors UGI Gas Exhibit E
3 (Proof of Revenue) and UGI Gas Exhibit F (Current and Proposed Tariffs).

4
5 **John D. Taylor** (UGI Gas Statement No. 11) is a Managing Partner of Atrium Economics
6 LLC. Mr. Taylor prepared and sponsors UGI Gas’s fully allocated cost of service study.
7 This study is contained in UGI Gas Exhibit D. The Allocated Cost of Service Study
8 (“ACOSS”) allocates the Company’s cost of service associated with Commission
9 jurisdictional operations to the Company’s customer classes. Mr. Taylor also addresses
10 the Company’s proposed revenue allocation and rate design, along with proposed changes
11 to the Company’s definition of normal weather and renewal of the Company’s Weather
12 Normalization Adjustment (“WNA”) pilot.

13
14 **Brian J. Meilinger** (UGI Gas Statement No. 12) is the Director – Customer Programs and
15 Public Relations at UGI. Mr. Meilinger’s testimony addresses the Company’s efforts to
16 provide affordable service. Mr. Meilinger also discusses the Company’s updates to its
17 WNA customer communications.

18
19 **III. NEED FOR RATE RELIEF**

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

22 A. UGI Gas is requesting an increase in its annual base rate operating revenues of \$99.368
23 million, or 8.05 percent on a total revenue basis, with a proposed effective date of March
24 29, 2026. The base rate increase requested in this filing utilizes a FPFTY ending September

1 30, 2027. UGI Gas continues to make substantial distribution system investments that are
2 necessary to: (1) continue the accelerated replacement of aging gas plant infrastructure; (2)
3 upgrade and improve system segments and modernize facilities; (3) serve new residential
4 and commercial customers, including natural gas conversions; (4) install and upgrade
5 supporting information technology systems; and, most importantly, (5) ensure the safety
6 of the Company's employees, customers, the communities it serves, and its distribution
7 system. Moving forward, these system improvements and investments will require the
8 Company to continue its efforts to attract, recruit, train, and retain those professional,
9 technical, and field-qualified personnel and resources necessary to implement, operate, and
10 maintain those investments, and to attract capital at a reasonable cost. These investments
11 are all necessary to grow and continue to maintain a safe and reliable distribution system
12 and provide quality customer service. As compared to pre-FPFTY gross plant levels, UGI
13 Gas is projecting an increase of approximately \$468 million in gross plant through the
14 FPFTY compared to the end of the FTY, and a total of \$879 million in gross plant when
15 compared to the end of the HTY. Based on this factor alone, UGI Gas's current rates will
16 not provide it with a reasonable opportunity to earn a fair rate of return on its increased rate
17 base investments.

18 Specifically, as reflected in UGI Gas Exhibit A (Fully Projected), Schedule A-1,
19 UGI Gas's operations are projected to produce an overall return on rate base of 6.55%,
20 which equates to a return on common equity of only 7.70% for the twelve-month period
21 ending September 30, 2027. As explained by UGI Gas witness Dylan W. D'Ascendis (UGI
22 Gas Statement No. 8), those returns are inadequate based on applicable financial analysis
23 and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief,
24 those projected returns will continue to decline. This could potentially jeopardize UGI

1 Gas's ability to attract the capital needed to make investments that support operating a safe
2 and reliable distribution system and enhance the reach and capacity of facilities that are
3 required for system growth. Moreover, with its requested rate relief, UGI Gas will have
4 the opportunity to earn a sufficient return on investments, serving as a needed source of
5 capital to continue replacing older, more risk prone facilities, systems, and equipment, each
6 of which is necessary to ensure continued system reliability, safety, and customer service
7 performance.

8
9 **Q. How have UGI Gas's expenses changed since its last base rate case?**

10 A. UGI Gas has been very successful in managing its expenses, and projects only an
11 approximate 1% increase in its overall Operations and Maintenance budget by the end of
12 the FPFTY. The expense increases include wage and salary adjustments where necessary
13 to maintain a productive and effective workforce, as well as increases in costs that are not
14 within the Company's direct control, such as PUC assessments and other price increases
15 for necessary products and services. UGI Gas continues to focus on efficient operations
16 and has seen stable customer growth over time.

17
18 **Q. Has the Company evaluated the impact of its proposed rate increase on average
19 customer bills generally?**

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

1

Table 1 – Average Customer Bill Impact

Average Residential Heating Customer Bill Impact				
Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
68.7 ccf	\$ 113.64	\$ 123.55	\$ 9.91	8.7%

Average Commercial Heating Customer Bill Impact				
Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
26.8 Mcf	\$ 336.74	\$ 358.17	\$ 21.43	6.4%

Average Industrial Customer Bill Impact				
Average Usage	Current	Proposed	Increase/ (Decrease)	% Change
54.6 Mcf	\$ 647.57	\$ 688.65	\$ 41.07	6.3%

2

3

4

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9

Q. Is the Company making any other key proposals in this general rate increase filing?

10

A. Yes. As required by the Joint Petition for Settlement in Docket No. R-2021-3030218, UGI

11

Gas must address its WNA Pilot program in a case filed before January 31, 2026. As such,

12

UGI Gas is proposing in this proceeding to extend and modify its WNA pilot for an

13

additional five years, ending October 31, 2032. Additionally, the Company is proposing

14

to establish Normal Heating Degree Days (“NHDD”) based on a 10-year weather history

15

for use in both its distribution rates and the calculation of the WNA. These proposals, as

1 well as the rate design and revenue allocation, are discussed in more detail in the testimony
2 of John D. Taylor (UGI Gas Statement No. 11).

3
4 **Q. Please describe UGI Gas's most significant accomplishments in recent years**
5 **demonstrating its commitment to customer safety, service reliability, and cost-**
6 **effective infrastructure investment.**

7 A. UGI Gas will accomplish a major safety milestone in 2026, when it completes the
8 retirement of all known cast iron on its distribution system. The Company also remains
9 on track to replace all of its bare steel mains by 2041. Additionally, as discussed above,
10 UGI Gas has maintained strong Operations and Maintenance (“O&M”) cost control
11 between the FTY and FPFTY, with only a 1% budgeted increase (excluding Gas Supply
12 and Depreciation & Amortization expenses). This discipline is best reflected in four key
13 drivers: (1) controlled salary costs, particularly in back-office functions; (2) minimal
14 growth in health benefits expenses; (3) an improved uncollectible rate; and (4) strategic
15 procurement efforts that optimized vendor pricing. Finally, the Company took significant
16 voluntary steps to protect low-income customers from the recent Federal Government
17 shutdown and its resulting impact on LIHEAP funding. The full range of the situation, its
18 potential impacts, and the Company’s response are described in the direct testimony of
19 Brian J. Meilinger, UGI Gas Statement No. 12. However, UGI Gas’s most critical actions
20 included making an additional \$500,000 contribution to Operation Share in fiscal year 2026
21 and suspending terminations for LIHEAP qualifying customers.

1 **Q. What actions has UGI taken to assist customers having difficulty paying their bills in**
2 **recent years?**

3 A. Since 2020, UGI has donated more than \$7.5 million dollars to Operation Share to support
4 customers facing economic hardship that are struggling to pay their bills. For Fiscal Year
5 2026, alone, UGI has donated more than \$1.5 million, including the \$500,000 donated in
6 response to the delay in the funding of LIHEAP.

7
8 **Q. Is UGI committing to any other actions to support the affordability of service for its**
9 **customers at this time?**

10 A. Yes. As part of this case, UGI is committing to contribute \$1,000,000 annually each year
11 for fiscal years 2027 to 2029 to its Operation Share program. These annual donations will
12 assist thousands of qualifying customers, who may receive up to \$600 in assistance in
13 paying their energy bills. This funding for Operation Share is a donation from UGI that is
14 not recoverable from or included in rates paid by customers, similar in nature to the many
15 other charitable donations and community giving made by UGI each year to support the
16 communities it operates in. Examples of the charitable donations and community giving
17 undertaken by UGI include annual donations of \$52,000 to the American Red Cross and
18 \$182,330 to 25 local organizations through United Way.

19

20 **Q. Does this conclude your direct testimony?**

21 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 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

P-2016-2537609 UGI Central Penn Gas, Inc., Distribution System Improvement Charge Cap Waiver

P-2016-2537594 UGI Penn Natural Gas, Inc., Distribution System Improvement Charge Cap Waiver

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

R-2024-3052716 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-2025-3059523

UGI Gas Utilities, Inc. – Gas Division

Statement No. 2

**Direct Testimony of
Tracy A. Hazenstab**

**Topics Addressed: Revenue Requirement
 Operating Revenues and Expenses**

Dated: January 28, 2026

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

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

5
6 **Q. By whom are you employed and in what capacity?**

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

12
13 **Q. What are your responsibilities as Sr. Manager - Utility Rates?**

14 A. I am primarily responsible for various tariff filings and related computations for UGI Gas
15 and UGI Electric rate and regulatory filings before federal and state regulatory
16 commissions. As part of these responsibilities, I am responsible for preparing and
17 supporting the Company’s revenue requirement models for this base rate filing, which is
18 included as UGI Gas Exhibit A. I report directly to the Vice President – Rates and
19 Regulatory Affairs of UGI.

20
21 **Q. What is your educational background?**

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

1 **Q. Please describe your professional experience.**

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

3

4 **Q. Have you testified previously before this Commission?**

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

8

9

II. PURPOSE OF TESTIMONY

10 **Q. What is the purpose of your testimony?**

11 A. I am providing testimony on behalf of UGI Gas in support of the Company's proposed
12 revenue requirement. First, I provide an overview of the Company's revenue requirement
13 exhibits for the historic year ended September 30, 2025 ("HTY"), future year ending
14 September 30, 2026 ("FTY") and the fully projected future test year ending September 30,
15 2027 ("FPFTY") (Section III). Second, I present UGI Gas's ratemaking presentation for
16 the FPFTY, including its revenues and operating expenses claims, and certain pro forma
17 adjustments (Section IV). The Company's rate proposal in this case is predicated on its
18 FPFTY exhibit, which demonstrates the need for a revenue increase of \$99.368 million.

19

20 **Q. What exhibits are you sponsoring in this proceeding?**

21 A. In addition to UGI Gas Exhibit TAH-1 mentioned above, I am sponsoring UGI Gas Exhibit
22 A (Fully Projected), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Historic). I am

1 also sponsoring certain responses to the Commission's standard filing requirements, as
2 indicated on the master list accompanying this filing.

3
4 **III. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS**

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

7 A. UGI Gas Exhibit A (Fully Projected) provides the calculation of the revenue requirement
8 for the FPFTY, including principal accounting exhibits, rate base claims, revenue at present
9 rates, operating expense claims, taxes and certain *pro forma* adjustments. The FPFTY
10 information is derived from UGI Gas's operating and capital budgets for the 12-month
11 period ending September 30, 2027. UGI Gas Exhibit A (Future) is the principal accounting
12 exhibit for the FTY, including certain *pro forma* adjustments. The FTY information is
13 derived from UGI Gas's operating and capital budgets for the 12-month period ending
14 September 30, 2026. UGI Gas Exhibit A (Historic) is the principal accounting exhibit for
15 the HTY, with appropriate ratemaking adjustments. The HTY information is derived from
16 the book accounting data for the 12-month period ended September 30, 2025. The future
17 and historic schedules are provided as a benchmark for comparison with the FPFTY claim,
18 which, as explained above, is the basis for UGI Gas's proposed revenue increase of \$99.368
19 million.

1 **Q. Please provide an overview of UGI Gas’s principal accounting exhibits.**

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

4 Section A summarizes UGI Gas’s requested *pro forma* rate base, revenues, and
5 expenses at present rates and the calculation of its requested revenue increase.

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

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

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

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

2 A. UGI Gas Exhibits A (Future) and A (Historic) follow the format of UGI Gas Exhibit A
3 (Fully Projected), but reflect data for the fiscal year ended September 30, 2026, and the
4 fiscal year ending September 30, 2025, respectively. This information is provided to
5 comply with the Commission’s filing requirements and provides a basis for comparing and
6 supporting the FPFTY claims with actual and projected results from the FTY and HTY.

7
8 **Q. What are the data sources for the UGI Gas Exhibit A (Future) and UGI Gas Exhibit
9 A (Historic)?**

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

13
14 **IV. REVENUE REQUIREMENT FOR THE FULLY PROJECTED FUTURE**
15 **TEST YEAR**

16 **Q. How is your discussion of UGI Gas’s FPFTY revenue requirement presentation
17 organized?**

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

1 **A. FPFTY REVENUE REQUIREMENT SUMMARY**

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

4 A. This calculation is shown at a summary level on Schedule A-1, column 3, of UGI Gas
5 Exhibit A (Fully Projected). Lines 1-9 summarize the *pro forma* measure of value (rate
6 base). Lines 10-19 show the following items at present rates: *pro forma* revenues, *pro*
7 *forma* expenses, taxes, taxes on the revenue increase, *pro forma* net operating income, and
8 the calculated rate of return. Lines 20-23 show the increase in net operating income
9 required to permit UGI Gas to earn the claimed overall rate of return of 8.20%. Application
10 of the Gross Revenue Conversion Factor establishes the revenue increase shown on line 25
11 needed to generate the change in operating income. Column 4 of Schedule A-1 shows the
12 level of the revenue increase and the increase in expenses associated with the revenue
13 increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at
14 proposed rates, as well as the resulting rate of return of 8.20%.

15
16 **Q. What is the overall requested increase in revenue?**

17 A. The overall requested increase in revenue is \$99.368 million. This represents the difference
18 between the *pro forma* FPFTY revenue requirement of \$1.334 billion and the annual level
19 of operating revenues of \$1.235 billion under existing rates. These figures are shown on
20 line 13 of Schedule A-1 of UGI Gas Exhibit A (Fully Projected). Please also see the direct
21 testimony of Hans G. Bell (UGI Gas Statement No. 1) for a discussion on certain
22 considerations made by UGI Gas in establishing this revenue increase amount.

1 **B. FPFTY RATE BASE**

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

4 A. UGI Gas’s rate base presentation is shown in UGI Gas Exhibit A (Fully Projected),
5 Schedule C-1. Schedule C-1 summarizes the UGI Gas rate base values for the FPFTY.
6 Column 1 indicates the schedule upon which the calculation of each of the rate base
7 elements is found. Columns 3 and 5 show the amounts at present and proposed rates,
8 respectively. UGI Gas’s total FPFTY rate base claim is \$4.319 billion. Please see the
9 direct testimony of Amy M. Keller (UGI Gas Statement No. 5) for a discussion of the rate
10 base components.

11
12 **C. FPFTY REVENUES AND EXPENSES**

13 **Q. How were revenues at present rates determined?**

14 A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect
15 the anticipated change in the number of customers, the projected change in existing
16 customer usage, the roll-in of revenues from the Distribution System Improvement Charge
17 (“DSIC”), and other *pro forma* annualizing and normalizing ratemaking adjustments. The
18 net effect of these adjustments is shown in UGI Gas Exhibit A (Fully Projected), Schedule
19 D-5, and is discussed in the direct testimony of Sherry A. Epler (UGI Gas Statement No.
20 10).

1 **Q. Please provide an overview of UGI Gas’s principal accounting exhibits relative to**
2 **operating expense claims.**

3 A. UGI Gas’s principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which
4 includes a presentation for the FPFTY ending September 30, 2027. Section D of UGI Gas
5 Exhibit A (Fully Projected) presents UGI Gas’s claims and necessary adjustments to
6 budgeted levels of expense items and revenues. The *pro forma* adjustments related to
7 expense are summarized in Schedules D-3 and D-6 through D-34. These expense
8 adjustments are used, in part, to derive UGI Gas’s *pro forma* income at present and
9 proposed rates as set forth in Schedule D-1.

10 UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) follow the format
11 of UGI Gas Exhibit A (Fully Projected) but reflect data for the appropriate test years ending
12 September 30, 2026, and 2025, respectively. This information is provided in accordance
13 with the Commission’s filing requirements and provides a basis for comparing and
14 supporting UGI Gas’s FPFTY claims with prior results.

15
16 **1. Summary**

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

18 A. Schedule D-1 presents a summary income statement that includes UGI Gas’s claimed gas
19 revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of
20 Sherry A. Epler (UGI Gas Statement No. 10) addresses the presentation of *pro forma*
21 revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the
22 proposed revenue increase of \$99.368 million on line 4 in column 2.

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

2 A. As shown on column 3, line 21, net income at proposed rates is \$354.186 million. This
3 represents a \$71.369 million increase from the level under current rates (\$282.817 million),
4 as shown on line 21 in column 1 of Schedule D-1.

5
6 **Q. Please describe Schedule D-2.**

7 A. Schedule D-2 shows the development of the various line items found on Schedule D-1.
8 Column 2 contains the Company's budgeted level of revenues and expenses for the 12-
9 month period ending September 30, 2027. Column 3 shows adjustments to the column 2
10 figures, where applicable, to reflect various annualization and/or normalization
11 adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase
12 and related expenses are shown in column 5 with the resulting revenues and expenses at
13 proposed rates shown in column 6.

14

15 **Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-**
16 **2, column 3?**

17 A. Yes. The derivation of the various column 3 revenue adjustments is included in UGI Gas
18 Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-13, and
19 then listed by individual adjustment on Schedule D-5. Customer charge and distribution
20 rate revenue adjustments for each customer class are shown on lines 1-5 of Schedule D-3.
21 Gas cost revenue adjustments for each customer class are shown on lines 6-10 and details
22 of other revenue adjustments are shown on lines 11-13 of Schedule D-3. Details for each
23 revenue adjustment are shown in Schedules D-5 (including supporting Schedule D-5A)

1 and are discussed in the direct testimony of witness Sherry A. Epler (UGI Gas Statement
2 No. 10). Another revenue adjustment, shown in Schedule D-5B, is sponsored by Darin T.
3 Espigh (UGI Gas Statement No. 9). This adjustment, in the amount of \$712,000, represents
4 the amortization of the CIAC Tax Gross Up Regulatory Liability for interconnects.
5 Regarding *pro forma* expenses, the derivation of the various adjustments is summarized
6 individually on pages 1-2 of Schedule D-3, lines 16-55. The details for these adjustments
7 are found in Schedules D-6 through D-31 and are sponsored by multiple witnesses, as
8 described in the Table of Contents of UGI Gas Exhibit A (Fully Projected) and as listed on
9 the header of each schedule.

12 2. Operating Expense

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

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

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

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

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

3 A. The detail for this adjustment is shown in Schedule D-6. This adjustment is designed to
4 increase purchased gas cost expense by the same amount as the gas cost revenue adjustment
5 contained in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 10) and as
6 shown on Schedule D-5, column 4, lines 7-11. UGI Gas recovers its purchased gas costs
7 on a dollar-for-dollar basis with no profit through an automatic adjustment clause
8 mechanism pursuant to Section 1307(f) of the Public Utility Code. Therefore, the decrease
9 in purchased gas costs of \$24.749 million equals the decrease in gas cost revenue as
10 detailed by Ms. Epler. Thus, with this adjustment, purchased gas cost expense has no effect
11 on the revenue requirement calculation.

12
13 **Q. Please discuss the Salaries and Wages adjustment shown on Schedule D-7 in the**
14 **amount of \$942,000.**

15 A. Schedule D-7, Column 4, shows a \$942,000 increase to budgeted salaries and wages to
16 reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense
17 and is distributed among the various cost accounts. Page 2 of Schedule D-7 shows the
18 development of this adjustment.

19
20 **Q. Please describe the annualization adjustment.**

21 A. This adjustment annualizes the effect of wage increases for unionized employees that will
22 take place during the FPFTY. Schedule D-7, page 2, line 2 reflects the increased

1 percentages for each classification of employee. Lines 3 through 5 indicate the percentage
2 of the year for which the salary and wage increases are not reflected in the budget.

3
4 **Q. How did you determine the split of the budgeted salaries among the various employee**
5 **classifications shown on Schedule D-7?**

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

11
12 **Q. What adjustments are shown on Schedule D-8?**

13 A. Schedule D-8 represents an adjustment in the amount of \$2.363 million for environmental
14 remediation expense. The adjustments are described in further detail in the direct
15 testimony of Amy M. Keller (UGI Gas Statement No. 5).

16
17 **Q. Please discuss Schedule D-10, which shows an adjustment for Rate Case Expense.**

18 A. Lines 1 through 4 show the rate case expense that UGI Gas expects to incur in this case of
19 \$1.760 million. That amount is then normalized over a one-year period given the
20 anticipated timing related to the next UGI Gas rate case. The budgeted amount of rate case
21 expense in the FPFTY was \$2.267 million. The budget was decreased by \$537,000 as
22 shown in Column 3, line 8 to reflect more current costs.

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

2 A. Schedule D-11 represents adjustments in the amount of (\$330,000) for uncollectible
3 expense. The adjustments are described in further detail in the direct testimony of Vivian
4 K. Ressler (UGI Gas Statement No. 4).

5
6 **Q. Please explain the adjustment in the amount of \$3.071 million shown on Schedule D-
7 14.**

8 A. Schedule D-14 represents an adjustment in the amount of \$3.071 million for pension
9 benefit expense. This adjustment is described in further detail in the direct testimony of
10 Amy M. Keller (UGI Gas Statement No. 5).

11
12 **Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Injuries and Damages.**

13 A. Schedule D-15, column 2, line 6, represents an adjustment in the amount of \$876,000 for
14 injuries and damages. This adjustment is described in further detail in the direct testimony
15 of Vivian K. Ressler (UGI Gas Statement No. 4).

16
17 **Q. Please discuss the Customer Accounts Expense Adjustment on Schedule D-15 in the
18 amount of \$1.624 million.**

19 A. The Company is required to pay interest on Customer Deposits that it holds in accordance
20 with its tariff requirements. Further discussion on customer deposits can be found in the
21 direct testimony of Vivian K. Ressler (UGI Gas Statement No. 4).

1 **Q. Please explain the PUC Assessment Adjustment also shown on Schedule D-15 in the**
2 **amount of \$875,000.**

3 A. This adjustment reflects an update to the budgeted PUC assessment expense in the amount
4 of \$875,000, column 2, line 10. Further discussion on this adjustment can be found in Ms.
5 Ressler’s testimony (UGI Gas Statement No. 4).

6
7 **Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service**
8 **expense.**

9 A. This adjustment normalizes the amount of Universal Services Program (“USP”) expense
10 recovered through the Company’s USP Rider based on the level of the Universal Service
11 Rider charge effective at the time of the Company’s filing in this matter. The USP Rider
12 recovers the Company’s Customer Assistance Program (“CAP”) Credits, Pre-Program
13 Arrearages, third party administrator expense, LIURP expense, and administrative costs
14 associated with its Operation Share program. The Company’s claim represents the ongoing
15 normalized level of costs based on anticipated levels of CAP program participation. This
16 adjustment decreases the Company’s budgeted expense by \$1.416 million, to align the
17 expense with the annualized amount of the Company’s current USP Rider charge. As the
18 USP Rider is a fully reconcilable rider, the USP adjustment assures that expenses related
19 to the existing rider are aligned with revenues and that no impact related to USP flows
20 through to the revenue requirement calculation and into net income. Please see the direct
21 testimony of Ms. Epler (UGI Gas Statement No. 10) for additional discussion of the USP
22 Rider.

1 **Q. Please explain the adjustment for Energy Efficiency and Conservation (“EE&C”)**
2 **Programs shown on Schedule D-19.**

3 A. As with the PGC and USP Rider adjustments discussed above, this adjustment in the
4 amount of \$(340,000) aligns the amount of EE&C expense with the EE&C Rider charge
5 (based on the level of the EE&C Rider charges effective at the time of the Company’s filing
6 in this matter). The EE&C Rider recovers the Labor and Administrative, Prescriptive
7 Program, Retrofit Program, New Construction Program, Legal and Consulting, Combined
8 Heat and Power, and other Costs associated with the Company’s Energy Efficiency and
9 Conservation Program. This adjustment decreases the Company’s budgeted expense to
10 align with the annualized amount of the Company’s current EE&C charge. As the EE&C
11 Rider is a fully reconcilable rider, the EE&C adjustment assures that expenses related to
12 the existing rider are aligned with revenues and that no impact related to EE&C flows
13 through to the revenue requirement calculation and into net income. Please see the direct
14 testimony of Ms. Epler (UGI Gas Statement No. 10) for additional discussion of the EE&C
15 Rider.

16
17 **3. Depreciation Expense**

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

19 A. UGI Gas’s depreciation study is set forth in UGI Gas Exhibit A (Fully Projected) and shows
20 the determination of *pro forma* depreciation expense. This study uses the FPFTY plant in
21 service and the applicable depreciation rates, service lives, and procedures. A summary of
22 the budgeted depreciation expense and adjustments thereto is found in UGI Gas Exhibit A
23 (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John
24 F. Wiedmayer (UGI Gas Statement No. 6).

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

2 A. UGI Gas witness Mr. Wiedmayer (UGI Gas Statement No. 6) presents the depreciation
3 analysis that serves as the foundation of the depreciation adjustment. The adjustment for
4 depreciation expense of (\$231,000) set forth on Schedule D-21, page 2, column 3, line 64,
5 annualizes budgeted FPFTY depreciation expense to calculate an entire year's worth of
6 depreciation on plant in service (as of the end of the FPFTY). This schedule also shows a
7 decrease to the net negative salvage amortization of \$1.197 million. The total annualized
8 depreciation expense for the FPFTY, net of costs charged to clearing accounts and net
9 salvage amortization, is \$170.518 million (as shown on Schedule D-3, page 2, column 13,
10 line 53).

11

12 **4. Taxes Other Than Income Taxes**

13 **Q. Please describe the taxes other than income adjustments in the amount of \$950,000**
14 **shown on Schedule D-31.**

15 A. Schedule D-31 contains the details for taxes other than income adjustments. The
16 adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio
17 of tax expense to payroll expense included in the FPFTY budget by the amount of the
18 payroll adjustment derived in Schedule D-7. This produces an adjustment to the amount
19 of social security, Federal Unemployment Tax ("FUTA") and State Unemployment Tax
20 ("SUTA") expense in the total amount of \$75,000. The calculation of these adjustments is
21 shown in more detail on Schedule D-32. The other components of this schedule are
22 supported in the testimony of Darin T. Espigh (UGI Gas Statement No. 9). In addition,
23 Schedule D-31 includes an adjustment in the amount of \$875,000 for the PUC Assessment,
24 as described previously in my testimony.

1 **5. Income Taxes**

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

3 A. These schedules show the derivation of the Company’s pro forma income tax expense
4 claim, including the normalization of the effects of accelerated tax depreciation, as
5 discussed in the direct testimony of Darin T. Espigh (UGI Gas Statement No. 9).

6
7 **6. Gross Revenue Conversion Factor**

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

9 A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on
10 Schedule A-1 to calculate the level of revenues required to achieve the net operating
11 income required to generate the rate of return supported by the direct testimony of Dylan
12 W. D’Ascendis (UGI Gas Statement No. 8). These additional revenues are required to
13 recognize that uncollectible accounts expense vary with the level of revenue and to
14 recognize the additional state and federal income taxes attributable to the proposed rate
15 increase.

16
17 **Q. Does this conclude your direct testimony?**

18 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
2025 UGI Gas Base Rate Proceeding:	Docket No. R-2024-3052716

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

JILL E. WALTER

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

Statement No. 3

**Direct Testimony of
Jill E. Walter**

Topics Addressed: Gas Safety and Operations

Dated: January 28, 2026

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Jill E. Walter. My current business address is 2121 City Line Ave Bethlehem,
4 PA 18107.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed as the Director of Operations - South Region by UGI Utilities, Inc. (“UGI”).
8 UGI is a wholly-owned subsidiary of UGI Corporation (“UGI Corp.”). UGI has two (2)
9 operating divisions, the Gas Division (“UGI Gas” or the “Company) and the Electric
10 Division (“UGI Electric”), each of which is a public utility regulated by the Pennsylvania
11 Public Utility Commission (“Commission” or “PUC”).

12
13 **Q. Please describe your educational background and work experience.**

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

15
16 **Q. What are your responsibilities as Director of Operations - South Region?**

17 A. As Director of Operations - South Region, I am accountable for over 400 individuals
18 including management, clerical, and field technicians that operate and maintain the
19 Company’s gas transmission and distribution system.

1 **Q. Have you presented testimony in proceedings before the Commission?**

2 A. No, I have not presented testimony in any proceedings before the Commission.

3

4 **Q. What is the purpose of your testimony?**

5 A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the
6 following topics: (1) natural gas operations; (2) regulatory compliance; (3) system safety
7 and reliability; (4) leak reductions and emergency response; (5) safety and training
8 initiatives; and (6) environmental programs.

9

10 **Q. Are you sponsoring any exhibits in this proceeding?**

11 A. Yes. I am sponsoring UGI Gas Exhibit JEW-1. I am also sponsoring those responses to
12 the Commission's standard filing requirements as stated on the master list accompanying
13 this filing.

14

15 **II. NATURAL GAS SYSTEM OPERATIONS**

16 **Q. Please provide an overview of the Company's distribution system.**

17 A. UGI Gas provides service to more than 700,000 residential, commercial, and industrial
18 customers located in 45 of Pennsylvania's 67 counties and spanning more than 700
19 municipalities. As of September 30, 2025, the Company operates more than 12,000 miles
20 of gas distribution mains and 300 miles of natural gas transmission mains in the
21 Commonwealth of Pennsylvania.

1 **Q. Please describe UGI Gas’s operations centers and support facilities.**

2 A. UGI Gas has operations centers and support facilities throughout its service territory.
3 Additionally, UGI Gas has a stand-alone centralized training center facility (“Learning
4 Center”) in Reading, PA, which includes a “safety town” for real-life indoor and outdoor
5 training inclusive of leak pinpointing and investigation, a separate welding and tapping
6 center, a safety lab, a service lab, a measurement and regulation lab, and a construction and
7 maintenance lab. The UGI Gas Learning Center supports Operator Qualification training
8 for both UGI Gas employees as well as contractors.

9

10 **Q. How does UGI Gas staff its operations?**

11 A. UGI Gas relies upon a mix of employees and contractor resources for its capital, operations,
12 and maintenance programs to accomplish many of its initiatives, including gas main and
13 service replacement and installation, roadway and landscape restoration, leak repairs, meter
14 reading, new business activities, and general system operation and maintenance. Further,
15 UGI Gas’s parent company, UGI Corp., provides management, administrative, and support
16 services (*e.g.*, executive management, human resources, legal, finance, accounting,
17 procurement, treasury, IT, and corporate governance).

18

19 **III. REGULATORY COMPLIANCE**

20 **Q. What regulations govern the safe transportation of natural gas transmission and**
21 **distribution pipelines?**

22 A. UGI Gas is subject to the minimum federal pipeline safety regulations in 49 CFR § 192 -
23 Transportation of Natural and Other Gas by Pipeline (“Part 192”). The Company must

1 also follow the applicable state pipeline safety requirements found in Pennsylvania Title
2 52, Chapter 59 - Gas Service and Hazardous Liquid Service (“Chapter 59”). Pennsylvania
3 natural gas pipeline safety regulations found in Chapter 59 of the Commission’s regulations
4 generally follow the Part 192 regulations.

5
6 **Q. What are the regulatory topics included in Part 192 regulations?**

7 A. Part 192 covers all aspects pertaining to the design, construction, operation, and
8 maintenance of natural gas pipelines owned and operated by the Company. Federal natural
9 gas pipeline safety regulations mandate that Operators have procedures and processes
10 touching upon the following:

- 11 • Design and Construction Standards
- 12 • Operation and Maintenance Procedures
- 13 • Emergency Plans
- 14 • Integrity Management Plans
- 15 • Damage Prevention Plans
- 16 • Public Awareness Programs
- 17 • Control Room Management Plans

18
19 **Q. How has the Company complied with these regulations?**

20 A. UGI Gas has several plans and procedural manuals in place to address all required
21 regulations found in Part 192. Due to the requirements found in Part 192, specifically
22 Subpart M which promulgates the maintenance requirements in Part 192, UGI Gas
23 performs a multitude of safety checks annually across its distribution system to maintain
24 system safety and reliability.

1 **Q. Can you provide examples of compliance safety checks UGI Gas performs annually**
2 **on its distribution system to comply with Part 192?**

3 A. The Company's Gas Operations personnel perform several activities to comply with
4 applicable Part 192 regulations as well as internal Company procedures. Some of these
5 activities include, but are not limited to, the following:

- 6 • Pipeline Leak Surveys and Patrols
- 7 • Valve Maintenance and Inspection
- 8 • Regulator Station Inspection and Maintenance
- 9 • Service Line Leak Survey and Meter Inspection
- 10 • Atmospheric Corrosion Inspection
- 11 • Cathodic Protection Inspection and Maintenance
- 12 • Odorant Intensity Inspection
- 13 • Transmission Integrity Management Assessments

14
15 The activities mentioned above are performed throughout the year and in certain situations,
16 multiple times on the same distribution or transmission asset annually. This work also
17 requires significant work planning/scheduling and record retention management.
18 Throughout the year, the Company's Gas Operations personnel perform several thousand
19 safety checks across its distribution system.

20
21 **Q. Does the Company undertake any voluntary actions that exceed federal requirements**
22 **found in Part 192?**

23 A. Yes. UGI Gas's plans and procedures exceed federal safety standards in a number of areas.
24 Additionally, UGI Gas voluntarily adopted and implemented programs identified as
25 industry wide best practices. One such example includes UGI Gas's implementation of
26 American Petroleum Institute ("API") Recommended Practice 1173 – Pipeline Safety
27 Management Systems ("PSMS"). UGI Gas's PSMS program is still in development and
28 continues to work toward full implementation in order to promote an enhanced safety

1 culture and provide safe and reliable natural gas service to its customers. In FY26, the
2 Company is developing formal processes related to incident investigation and management
3 of change in accordance with the standard as well as formal PSMS training within the
4 organization. In addition, the Company completed a Safety Culture Assessment in 2025
5 to understand opportunities to improve safety.

6 In other situations, UGI Gas has elected to implement voluntary actions that arise
7 from national events or recommendations by the National Transportation Safety Board
8 (“NTSB”) and other governmental agencies where it believes that doing so will allow it to
9 provide safer and/or more reliable service to its customers. As noted in the Company’s
10 prior base rate case testimony at Docket No. R-2024-3052716 (“2025 Rate Case”), an
11 example of this voluntary compliance relates to UGI Gas’s evaluation of over-
12 pressurization protection (“OPP”) utilized on its low-pressure systems. As an update to
13 this prior testimony, as of September 5, 2025, of the 73 stations identified that were not
14 compliant with the additional OPP that was recommended by the NTSB, all of them have
15 been addressed through the installation of supplemental OPP, station abandonment, or
16 regulator station replacement.

17
18 **Q. Does the Company have integrity management plans?**

19 A. Yes, the Company maintains a Transmission Integrity Management Program (“TIMP”)
20 and Distribution Integrity Management Program (“DIMP”) and as mandated in 49 C.F.R.
21 § 192, Subpart O – Gas Transmission Pipeline Integrity Management, and Subpart P – Gas
22 Distribution Integrity Management.

1 Under Subpart O, UGI Gas must continually identify threats to its pipelines in high
2 consequence areas (“HCAs”), moderate consequence areas (“MCAs”), and other
3 designated areas along transmission lines to determine the risk posed by any identified
4 threats. UGI Gas also must schedule and perform integrity assessments to address all
5 applicable threats, collect information about the condition of the pipelines, and take risk
6 reduction actions to minimize and mitigate applicable threats.

7 Under 49 C.F.R. § 192, Subpart P, operators of gas distribution pipelines are
8 mandated to gather information regarding their distribution pipelines and identify and
9 evaluate relevant threats to their distribution systems. Operators are also required to assess
10 and prioritize risks associated with the distribution system, implement accelerated action
11 aimed at mitigating the risks of pipeline failures, and assess the effectiveness of these
12 actions. Furthermore, operators must establish and execute a process for the regular review
13 and enhancement of their programs, as well as report their findings to regulatory
14 authorities. Unlike TIMP, DIMP encompasses the entire distribution system rather than
15 focusing solely on pipelines located in select areas along transmission lines. This is due to
16 distribution pipelines being predominantly situated in urbanized, densely populated regions
17 to supply gas to these communities.

18
19 **Q. Does the Company train and qualify its field personnel prior to performing**
20 **operations and maintenance activities on natural gas pipelines?**

21 A. Yes, UGI Gas maintains an Operator Qualification Plan (“OQ Plan”) complying with the
22 requirements of 49 CFR § 192, Subpart N. The OQ Plan establishes requirements for and
23 management of qualifications for pipeline personnel who perform covered tasks on a

1 pipeline. Pipeline personnel are trained and qualified under the tasks needed to perform
2 their various work activities on a UGI Gas pipeline. Covered tasks ensure internal and
3 external pipeline personnel are educated, tested, and competent to perform specific natural
4 gas activities on UGI Gas's distribution system. UGI Gas's OQ Plan was updated to
5 incorporate industry standard ASME B31Q tasks effective December 8, 2025, and includes
6 over 160 unique covered tasks, which ensure internal and external pipeline personnel are
7 educated, tested, and competent to perform specific natural gas activities on UGI Gas'
8 distribution system.

9 Additionally, UGI Gas is implementing a new OQ management system to track
10 employee and contractor qualifications compliance. This system will provide digital
11 access to OQ records. One of the key advantages of the new system is the ability for
12 supervisors or inspectors to scan an employee or a contractor's QR code while in the field
13 to view their OQ record status.

14 **IV. SYSTEM RELIABILITY AND SAFETY**

15 **Q. Please describe the physical composition of UGI Gas's distribution system.**

16 A. Due to its long-term operation, the Company's distribution system includes a mixture of
17 pipeline materials indicative of the industry's technological advancement over time. Cast
18 iron mains historically were found in the oldest parts of the system. UGI Gas, and the
19 industry in general, then transitioned to bare steel and wrought iron piping, which were
20 prevalent until the 1960s. The first generation of plastic piping was introduced in the early
21 1970s. Materials installed since the 1970s include various types and compositions of
22 polyethylene ("PE") and coated steel piping. Overall, approximately ninety percent (90%)
23

1 of UGI Gas’s distribution mains consist of contemporary materials, which UGI Gas defines
2 as cathodically protected steel and modern plastic. UGI Gas’s natural gas distribution
3 system has the highest percentage of contemporary mains among major natural gas
4 distribution companies in Pennsylvania. Additionally, as of December 31, 2025, UGI Gas
5 only has approximately 3 miles of cast iron main left on-system.

6
7 **Q. Please discuss the Company’s actions to improve and enhance its distribution system.**

8 A. UGI Gas has been identifying and repairing, improving, or replacing its distribution
9 infrastructure on an accelerated basis pursuant to Commission-approved Long Term
10 Infrastructure Improvement Plans (“LTIIP”). The Company’s Initial LTIIP¹, Second
11 LTIIP², and the first year of the Third LTIIP have resulted in UGI Gas successfully
12 removing more than 802 miles of main over the 11-year period from 2014 to 2025
13 including 99% of its total cast iron mains and 48% of its total bare steel/wrought iron mains.
14 UGI Gas continues to invest in improving and modernizing its distribution facilities serving
15 customers throughout the Company’s service territory. The Company filed its Third LTIIP
16 on August 16, 2024, and this plan was approved by the Commission on December 5, 2024,
17 at Docket No. P-2024-3050769. During the 12-month period from January 1, 2025,
18 through December 31, 2025, the Company has exceeded its Third LTIIP estimate by

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.

1 replacing approximately 71 miles of total cast iron, bare steel, wrought iron, and priority
2 plastic mains compared to the Third LTIP's plan of 50-60 miles. Additionally, DSIC-
3 eligible capital placed into service in calendar year ("CY") 2025 totaled approximately
4 \$330 million compared to the Third LTIP's plan of \$298.5 million. In addition to main
5 replacements in the Third LTIP, the Company is pursuing other infrastructure initiatives,
6 including replacing service lines, meter sets, valves, and farm taps, as well as addressing
7 safety upgrades relating to measurement and regulation facilities (e.g., making
8 improvements to over-pressure protection equipment) and remediating mechanical tees.
9 Additionally, the Company outlined a plan for replacement of priority plastic, which
10 includes plastic installed between 1965 and 1985. The Company retired approximately 8.5
11 miles of priority plastic in calendar year 2025. These initiatives will make UGI Gas's
12 system safer and more reliable. Continuing UGI Gas's infrastructure replacement program
13 as outlined in its Third LTIP will allow the Company to provide safe and reliable service
14 both now and into the future.

15
16 **Q. How does UGI Gas prioritize its pipeline replacement projects?**

17 A. In 2019, UGI Gas began using the Data-Driven risk model ("DDRM"). The DDRM is a
18 quantitative model incorporating leak repair data, incident data, and asset population data
19 to calculate a risk index score for facility groupings referred to as Asset Threat Groups
20 ("ATGs"). The DDRM is utilized in conjunction with the Subject Matter Expert ("SME")
21 driven risk model in order to validate DDRM results by incorporating SME input.

22 The DDRM provides a quantitative basis for evaluating risk and creates a stable
23 foundation for comparing year-over-year changes because of the consistent quantitative

1 underpinning utilized. Finally, the DDRM facilitates evaluation of other risk mitigation
2 approaches, including additional operations and maintenance, leak survey and damage
3 prevention measures.

4
5 **Q. What are the Company's current goals for main replacement?**

6 A. UGI Gas is on track to replace all its cast iron main no later than February 2027, consistent
7 with its initial completion plan and prior commitments. Further, the Company is on track
8 to complete its bare steel and wrought iron main replacement no later than September 2041,
9 also consistent with its initial completion plan. Specifically, to maintain a pace of
10 replacement that would achieve these objectives, the Company's Third LTIP established
11 the objective of replacing between 60 and 70 miles of main in calendar year 2026 with an
12 increase to 75 to 85 miles in calendar year 2027. As part of its mileage identified in calendar
13 year 2027, the Company is planning an abandonment of a large section of a wrought iron
14 and bare steel line in the northern part of the Company's service territory due to
15 corrosion. This project will retire approximately 15 miles of high pressure wrought iron
16 and bare steel. The Company plans to return to replacing 60 to 70 miles of main in CY28
17 and CY29.

18
19 **Q. What results has UGI Gas achieved in the first year of its Third LTIP?**

20 A. The Company replaced or retired approximately 71 miles of main in 2025 including 23
21 miles of cast iron, 40 miles of bare steel, and 8 miles of vintage plastic. In addition, the
22 Company installed 14,230 excess flow valves. The Company also replaced 11,651

1 services in 2025, 7,208 of which included meter sets that were moved from indoors to
2 outdoors. The Company plans to continue replacing 10,500 to 12,500 services per year.

3
4 **Q. What is UGI Gas’s projection of its replacement and betterment plant in service for
5 the future test year (“FTY”) and the fully projected future test year (“FPFTY”)?**

6 A. For the FTY, the replacement and betterment budget reflects \$311.5 million plant in
7 service. The FPFTY plant placed in service for replacement and betterment is budgeted to
8 be \$383.6 million. For more detail on the Company’s budgeting process related to all
9 planned capital activities, please refer to the direct testimony of Vicky A. Schappell (UGI
10 Gas Statement No. 7).

11
12 **Q. What is the Company’s basis for showing a further increase in plant placed in service
13 in the FTY and FPFTY?**

14 A. Foremost, the Company’s annual plant additions related to replacement and betterment
15 activities increased nearly \$63 million over the 2021-2025 period, from \$230 million in
16 2021 to \$293 million in 2025. The Company anticipates that the cost of its replacement
17 and betterment work will continue to increase through the FPFTY due to a number of
18 different elements. The Company is further accelerating the number of miles it will
19 accomplish in the FTY and FPFTY and has expanded work done to address safety upgrades
20 and improvements that are not exclusively mileage-based replacements, such as meter
21 moveouts, system reinforcement projects and regulator station rebuilds. In addition, the
22 Company’s piping projects include larger diameter bare steel pipes, and a greater focus on
23 priority plastic in the FPFTY. For these reasons, UGI Gas’s budget for the FTY and the

1 FPFTY reflects increased plant additions beyond the amount that the Company had
2 accomplished during the HTY.

3
4 **Q. Please discuss the Company's ongoing plans to move its indoor meter facilities**
5 **outdoors.**

6 A. UGI Gas is working to have all meters located outside by 2034 as required by the
7 Commission's regulations at 52 Pa. Code 59.18, with limited exceptions as allowed by
8 code. UGI Gas is taking a risk-based approach, while keeping efficiency in mind, to
9 prioritize meters being moved outside based on the service line attributes and their
10 associated risks and whether these services are attached to a main that will require
11 replacement prior to 2034. As of October 1, 2025, the Company had a population of 84,554
12 meters inside customer's homes or businesses. UGI Gas plans to move approximately
13 10,500 meters outside per year or 31,500 meters between the HTY and FPFTY.

14
15 **V. LEAK SURVEYS, LEAK REDUCTIONS, EMERGENCY RESPONSE AND**
16 **METHANE DETECTORS**

17 **A. Leak Surveys**

18 **Q. Please discuss UGI Gas's efforts to identify, manage, and reduce system leaks.**

19 A. UGI Gas monitors safety and reliability indicators for its natural gas distribution system on
20 an ongoing basis to evaluate corrosion and leak identification and resolution performance,
21 track emergency response, and pursue damage prevention – all of which will drive
22 improvements in employee and public safety. As a part of its DIMP,³ UGI Gas regularly

³ 49 C.F.R. § 192.1007.

1 re-assesses system risks and leak trends to determine if additional or accelerated actions
2 are required to further reduce system leaks.

3
4 **Q. How does the Company perform leak surveys of its distribution system assets?**

5 A. UGI performs both walking and mobile leak survey activities on its mains and services.
6 UGI completes these activities using approved equipment as outlined in the Gas Operations
7 Manual (GOM 70.10.10). Minimum frequencies for leak surveying by material type or
8 location are also listed in the Gas Operation Manual. UGI completes these surveys at least
9 at the minimum required cycles with a combination of internal and external resources.

10
11 **Q. Please describe the Company's leak survey practices for its priority plastic pipe.**

12 A. Priority plastic installed in the UGI Gas system contains DuPont Aldyl-A plastic pipe,
13 which can be susceptible to failures over time dependent upon local environmental
14 conditions and installation practices. The total length of priority plastic mains installed on
15 UGI Gas's distribution system between the years of 1965 and 1985 is approximately 1,100
16 miles. Current leak survey frequencies for this asset population are generally on a 5-year
17 cycle in line with federal regulations, although UGI Gas typically performs these surveys
18 on a 4-year cycle. Starting with the Calendar Year 2026 leak survey cycle, UGI Gas will
19 perform accelerated leak surveys on an annual basis for its priority plastic mains.
20 Importantly, this data feeds into the Company's DIMP for evaluation, risk ranking, and
21 replacement prioritization.

1 **Q. How has the Company implemented Advanced Mobile Leak Detection (“AMLD”)**
2 **Technology to date?**

3 A. UGI Gas began its initial pilot of AMLD in 2021. The Company purchased one AMLD
4 device and subsequently installed it on a Company vehicle. During the initial phase, the
5 vehicle was driven along 445 miles of main in the Northern district. In subsequent years,
6 UGI Gas continued to pilot this unit and other competing AMLD technologies within its
7 service territory to aid in the analysis and development of its AMLD program. In CY25,
8 UGI Gas laid forth the plan to start the execution of AMLD work in the system starting in
9 CY26.

10
11 **Q. Can you describe the results of the Company’s AMLD pilots?**

12 A. Yes. The pilot resulted in the following learnings:

- 13 • AMLD technology can survey a much wider dynamic range than conventional Cavity
14 Ring-Down Spectroscopy (“CRDS”) and Tunable Diode Laser Absorption
15 Spectroscopy (“TDLAS”) methods.
- 16 • AMLD technology allowed UGI Gas to perform mobile main-line leak survey at
17 speeds five to ten times greater than traditional main line survey.
- 18 • AMLD identified existing/known leaks 100% of the time on the routes surveyed. 81
19 existing leaks were found along with 64 new system leaks.
- 20 • For 208 confirmed underground indications, 10% of the leaks found with the AMLD
21 equipment represented around 75% of the total emissions, which prove the technology
22 is effective at finding very low level leaks.
- 23 • This technology can undergo rapid deployment during emergencies/special surveys to
24 ensure system resiliency (e.g. earthquake, post-flooding, or incident response.)

1 **Q. What are UGI Gas’s long-term plans for AMLD Technology?**

2 A. In CY26, UGI Gas will utilize the Company-owned AMLD device to survey between 600
3 and 1,200 miles of main across its territory, equating to approximately 5-10% range of the
4 drivable miles. The CY26 work will be done in conjunction with traditional leak survey
5 methods which are currently still required to meet UGI Gas’s compliance activity. The
6 main driver of the work in CY26 will be data collection to share with the Commission’s
7 Safety Division to develop an approach that appropriately incorporates AMLD in future
8 years to fulfill UGI Gas’s leak survey regulatory obligations. The additional information
9 gained from this technology will identify new environmental risk reduction opportunities
10 while also being leveraged within UGI Gas’s DIMP to provide additional knowledge on
11 the asset populations contained within the DIMP.

12

13 **B. Leak Reductions**

14 **Q. How does UGI Gas classify leaks?**

15 A. UGI Gas uses a standardized leak classification system consistent with general industry
16 protocols. Specifically, underground leaks are classified as ‘A,’ ‘B,’ and ‘C.’ Class ‘C’
17 leaks are deemed hazardous, and repair work is undertaken immediately. Class ‘B’ leaks
18 are non-hazardous at the time of detection but justify a scheduled repair. Pursuant to UGI
19 Gas’s practice, Class ‘B’ leaks must be repaired or cleared within one calendar year, but
20 no later than 15 months from the date of the latest Class ‘B’ leak classification. UGI Gas
21 has been focused on continuous improvement for Class ‘B’ leak repairs. To that end, the
22 Company repaired 98.2% of Class ‘B’ leaks within six months of classification in Fiscal
23 Year 2025. These accelerated repairs reduced the leak hazards as well as methane

1 emissions. Class 'A' leaks are deemed non-hazardous and are monitored for changes in
2 severity.

3 In December 2023, UGI Gas established formal classifications and procedures for
4 aboveground leaks on UGI Gas owned facilities. Prior to this, UGI Gas did not classify
5 aboveground leaks. These aboveground leaks are classified as Class 'G' and 'H.' Class
6 'G' leaks are defined as a minor escape of gas from aboveground UGI Gas piping or related
7 gas facilities that is in a location that does not endanger the public and should be repaired
8 or cleared within five calendar years, not to exceed 63 months from the date of the latest
9 Class 'G' leak classification. Class 'H' leaks are defined as an unintentional escape of gas
10 from aboveground UGI Gas piping or related gas facilities that requires immediate repair
11 or make safe action.

12
13 **Q. How have UGI Gas's system leaks improved since 2018?**

14 A. UGI Gas has seen a significant reduction in the number of leaks found on its system. This
15 is directly attributable to its prioritization and aggressive replacement of leak-prone mains,
16 services, and other assets. As Table 1 below demonstrates, since 2018, Class 'C' leak
17 repairs have decreased by 59.9%, Class 'B' leak inventories have decreased by 76.0%, and
18 Class 'A' leak inventories have decreased by 52.3%.

1

Table 1. Leak Inventories & Repairs

	Calendar Year 2015	Calendar Year 2025	Percent Change
C Leak Repairs	1,953	783	59.9% decrease
B Leak Inventory	816	196	76.0% decrease
A Leak Inventory	4,877	2,327	52.3% decrease

2

3 **C. Emergency Response**

4 **Q. Please discuss UGI Gas’s performance in the area of emergency response.**

5 A. UGI Gas performs exceptionally well in the timely response to emergency
6 notifications/calls. For the Fiscal Year ended September 30, 2025, 99% of the time, a first
7 responder arrived on the premises within 45 minutes (or less) of receipt of an emergency
8 call. UGI Gas utilizes a combination of shift coverage and on-call schedules to leverage
9 internal field and supervisory resources to provide emergency response coverage 24-hours
10 per day, 365 days per year. UGI Gas sets performance goals on a 45-minute response,
11 which is more stringent than the benchmark response time as defined by the Commission’s
12 Safety Division.⁴ Moreover, for Fiscal Year 2025, 99.8% of the time a UGI Gas first
13 responder arrived onsite within one hour of the emergency call. UGI Gas also had an
14 average emergency dispatch time of only 2.95 minutes for Fiscal Year 2025.

⁴ 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).

1 **D. Methane Detectors**

2 **Q. Provide a summary of UGI Gas’s efforts to install in-home methane detection devices**
3 **pursuant to the Commission-approved Settlement in the 2025 Rate Case.**

4 A. UGI Gas is piloting the use of in-home methane detection devices as an additional layer of
5 protection for natural gas customers. The initiative began in FY 2026 (ending September
6 30, 2026), and will continue through the FPFTY. This initiative is designed to evaluate the
7 effectiveness of commercially available methane detectors in providing early warning of
8 potential gas leaks within customer homes. The pilot will allow UGI Gas to assess device
9 performance, installation considerations, customer engagement, and the overall impact on
10 safety outcomes. By proactively evaluating this technology, UGI Gas aims to determine
11 whether broader deployment could enhance public safety, reduce response times, and
12 further strengthen the Company’s comprehensive approach to leak detection and
13 mitigation.

14 UGI Gas is also testing cellular and LoRaWAN remote communication as well as
15 non-communication units. UGI Gas has deployed ~100 units as of the end of CY25. These
16 units have been distributed to Company employees that are UGI Gas customers to act as
17 Natural Gas Safety Ambassadors for this technology. After achieving learnings for the
18 pilot, UGI Gas will shift to customer-focused education efforts in CY 2026. UGI Gas will
19 look to add a dedicated Natural Gas Detector safety page to its website and also add a
20 Natural Gas Safety section to its Energy Efficiency and Conservation website where
21 customers can purchase Natural Gas Detectors that UGI Gas has ensured are UL 1484
22 approved.

1 UGI Gas is continuing to focus on High Energy Hazard Assessment and Energy
2 Control in line with the Edison Electric Institute’s Safety & Classification Learning Model,
3 an industry-standard approach to categorizing safety learning opportunities to reduce
4 potentially serious or fatal injuries. The UGI Gas Safety team is continuing to train
5 employees in use of the model for hazard assessment for job planning in FY26 and FY27.

6 In FY26, UGI Gas plans to initiate an Occupational Health Program pilot aimed at
7 reducing soft-tissue injuries. The pilot focuses on proactive injury prevention through
8 onsite ergonomic assessments, individualized conditioning programs, and early-
9 intervention strategies to address discomfort before it progresses to an injury. The program
10 includes employee education on proper body mechanics, stretching and warm-up routines,
11 and techniques to safely perform high-risk tasks such as lifting, bending, and repetitive
12 motion. By integrating occupational health expertise directly into field operations, UGI
13 Gas is working to reduce strain-related injuries, improve employee well-being, and
14 enhance overall operational safety and productivity. The Company will review and
15 evaluate the findings from the pilot in CY26 to determine how to proceed with further
16 implementation in CY27.

17
18 **Q. What other ongoing safety programs does the Company have?**

19 **A.** Other ongoing safety measures and tools include Smith System driver training and a 24-
20 hour Triage Nurse Hotline. The Company has also adopted multiple programs to enhance
21 its safety protocols. One such program is the UGI “Making a Difference by Living Our
22 Values” incentive program, which rewards employees who demonstrate positive safety
23 behaviors, including, but not limited to, leading safety meetings, reporting safety issues, or

1 participating in safety education. UGI Gas has further implemented a “Near Miss/Good
2 Catch” program, which seeks to proactively prevent safety incidents by learning from
3 issues that had the potential for, but did not result in, damage or harm. In addition, the
4 Company uses EcoOnline, a safety incident software, which facilitates incident
5 management and data collection for various types of incidents and tracks those incidents
6 through the investigation process. Moreover, the Company utilizes ISNetworld vendor
7 safety software to qualify contractors and monitor their performance trends. ISNetworld
8 collects safety information from these contractors and compares them against UGI Gas’s
9 established safety standards to make sure their safety performance is at a satisfactory level
10 to perform work for the Company. ISNetworld conducts ongoing monitoring of the
11 contractor’s safety information and alerts UGI Gas if a contractor falls below the
12 Company’s minimum safety standards – either in UGI Gas’s service territory or anywhere
13 else in the country. This helps ensure that UGI Gas’s contractors provide safe and reliable
14 service to the Company’s community and customers.

15
16 **Q. What training initiatives is the Company undertaking?**

17 A. The Company has advanced its offerings at its Learning Center and continues to enhance
18 the training program abilities there. The Learning Center is used for all new hire and
19 employee progression field training. It is also used for ongoing training and operator re-
20 qualification for employees and contractors. Key enhancements in Fiscal Years 2024-2025
21 were developing (1) training curriculum for meter and regulation field employees,
22 incorporating Asset Data Collection (“ADC”) training into existing course offerings; and
23 (2) specialized training in medium and high pressure tapping.

1 The Company’s OQ and technical training team has completed reorganizing,
2 revising, and reformatting the training curriculum to enhance learning through
3 incorporation of additional hands-on practice elements and interaction afforded at the
4 Learning Center. The Company has aligned its operator qualification tasks with the
5 American Society of Mechanical Engineers (“ASME”) B31Q Standard. This transition to
6 the B31Q standard aligns the Company with the latest industry best practices. This was
7 completed in December 2025.

8 In FY25, UGI Gas implemented comprehensive Safety Leadership training for
9 supervisors and above to strengthen UGI Gas’ safety culture. The program focused on
10 equipping leaders with the skills needed to model safe behaviors, conduct effective safety
11 conversations, identify and mitigate hazards, and reinforce accountability across teams. In
12 addition, UGI implemented human performance training to approximately 80% of its field
13 workforce with the remaining 20% to be implemented in FY26. By enhancing leadership
14 capability at all levels, these initiatives foster a work environment where employees feel
15 empowered to speak up and prioritize safety in every task. As a result, UGI Gas expects
16 long-term improvements in incident prevention, operational reliability, and overall
17 employee engagement.

18

19 **VII. ENVIRONMENTAL PROGRAMS**

20 **Q. Please discuss environmental management at UGI Gas.**

21 A. The environmental group at UGI Gas is focused on three main areas: (1) Manufactured
22 Gas Plant (“MGP”) remediation; (2) compliance activities, such as permitting and
23 operational improvements; and (3) sustainability and methane reduction activities.

1 **Q. Please describe the Company’s investigation and remediation of environmental**
2 **impacts related to historical operations.**

3 A. From the mid-1800s through the mid-1900s, UGI Gas and its predecessors owned and
4 operated a number of MGPs that, prior to the general availability of natural gas, generated
5 gas from other fuel stocks for residential, commercial, and industrial customer use. In
6 Pennsylvania, this process generally used coal as a fuel stock. Some byproducts of this
7 manufacturing process, including coal tars and other residues of the manufactured gas
8 process, are today considered potentially hazardous substances under state and federal
9 environmental laws. UGI Gas operates its environmental remediation program under a
10 consent order and agreement (“COA”) with the Pennsylvania Department of
11 Environmental Protection (“PADEP”) that covers the Company’s activities through
12 October 1, 2035.⁵ This COA obligates the Company to either meet an annual minimum
13 environmental spend commitment of \$5.35 million or achieve a minimum annual point
14 total of 9,000 points,⁶ with points being issued for the completion of various designated
15 environmental tasks under the COA through October 1, 2035.

⁵ Historically, UGI Gas operated its environmental remediation programs under three COAs with 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 the single, current COA that runs through October 1, 2035.

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.

1 **Q. What types of costs does UGI Gas incur with respect to addressing MGP site**
2 **conditions?**

3 A. UGI Gas incurs costs for site investigations, remediation, and site restoration as well as
4 related PADEP oversight costs. Costs may also be incurred to obtain an environmental
5 covenant at the site to prevent certain uses of the site, and costs associated with transferring
6 the site to a third party (such as with a dedication for public use) once the site has been
7 restored. Costs may also be incurred to purchase a property to secure access to investigate
8 and remediate. Additionally, expert and legal costs are sometimes incurred in interactions
9 with insurance carriers or other potentially responsible parties to ensure that UGI Gas's
10 customers are only paying their equitable share of investigation and remediation costs.
11 These costs may also be incurred to implement PADEP workplans if the Company faces
12 opposition to the investigation or remediation of the site. Costs may also be incurred to
13 recover compensation under historical insurance policies to offset the costs that would
14 otherwise be recovered from customers.

15
16 **Q. What is UGI Gas's projected spending on the MGP program?**

17 A. UGI Gas has held the COA annual minimum spend of \$5.35 million as the target projected
18 spend for each year to meet the COA objectives, if minimum annual points cannot be
19 achieved. UGI Gas's average aggregate annual spending over the past three fiscal years is
20 \$6.698 million, as shown below in Table 2.

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16

Table 2. Environmental Spent per Fiscal Year

Fiscal Year	Total
2023	\$5,441,000
2024	\$7,602,000
2025	\$7,052,000
Average	\$6,698,000

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 Amy M. Keller (UGI Gas Statement. No. 5).

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.

1 **Q. What is UGI Gas's goal for restoration of the MGP sites?**

2 A. UGI Gas strives to restore each site for beneficial reuse that becomes an asset to the
3 Company or the community. Because these MGP sites are located within the Company's
4 existing service territory, restoration of the sites for beneficial reuse, whether in the form
5 of use by the Company, urban redevelopment, or the creation of a new public space,
6 directly benefits the customers and communities served by the Company.

7

8 **Q. Does that conclude your testimony?**

9 A. Yes, it does.

UGI GAS

EXHIBIT JEW-1

Utility Operations & Safety Leader | Business Process Improvement

Dynamic and results-driven utility operations leader with over 20 years of progressive experience driving performance, leading teams, and delivering strategic initiatives in high-pressure environments. Proven expertise in business process improvement, change management, and cross-functional collaboration. Recognized for a clear, effective communication style that connects across all organizational levels to build alignment and momentum. Adept at translating customer needs into actionable strategies and fostering strong trust-based relationships. A hands-on, influential leader with a strong blend of critical thinking, problem-solving, and operational excellence. **Areas of expertise include:**

**Safety & Quality Program Management ♦ Root Cause Analysis ♦ Operations Management ♦ KPI Management
Process Improvement & Automation ♦ Budget Management ♦ Forecasting ♦ Risk Management ♦ Cost Control
Customer Service ♦ Contract Management ♦ Policy & Procedure Development ♦ Effective Communication
Data Analytics & Reporting ♦ Executive Collaboration ♦ Team Leadership Business & Financial Analysis**
Technologies: Microsoft Office Suite, SharePoint, Oracle, Work Management Software, Accounting Software

CAREER SUCCESS

UGI Utilities, Bethlehem, PA

January 2023 – Present

Director Operations, South Region (January 2023 – present)

Direct and lead natural gas employees within the South Region (~400 employees) in safe, reliable and efficient natural gas installation, operation, and maintenance. Ensure fiscal responsibility for the South Region while driving efficiency in work processes. Provide leadership and promote communication and collaboration between departments across the company.

INTREN, Conshohocken, PA

October 2018 – January 2023

Regional Director, East (2018-2023)

Direct and lead gas and electric employees within in the East Region driving INTREN's core values and mission (~180 employees). Primary point of contact responsible for maintaining customer relationships and satisfaction within the region. Responsible for execution of contracts and the region's operating budget performance. Responsible for developing and implementing business development strategies within the region to promote growth. Drives a culture that embraces safety and quality and ensures safety and quality procedure adherence.

- Full P&L responsibility for ~\$60m budget
- Improved gross margin by 12% in 2 years
- Led region through 300% growth in revenue over 4 years
- Improved OSHA recordable incidents within the region
- INTREN representative on NECA Northeast Lines Chapter

I.B. Abel, Inc., York, PA

January 2015 – September 2018

Director of Safety & Quality (2016-2018)

Directed and led employees within the Safety & Quality Department, including hiring, training and coaching. Managed the safety & quality management system by engaging customer, field and senior leadership. Increased quality, safety and efficiency by implementing process and IT improvement initiatives. IT focus areas include mobile computing, SharePoint and the tool & equipment request system. Managed all key performance metrics for the company including safety, project management, work management, financial, backlog, and resource planning.

- Improved OSHA recordable incidents by 30% through a proactive safety and human performance program.
- Developed company SharePoint site to provide office and field employees the ability to electronically submit timesheets, access customer specifications, request tools/equipment and submit company forms. Deployed tablets to approximately 100 field leadership employees.
- Developed and implemented the company's ISO 9001:2015 compliant Quality Management Program.
- Developed a corporate scorecard as well as department level scorecards to measure business performance.

- Implemented a standard project management delivery process across all divisions improving project communications, reporting, efficiency, and profitability.
- Single point of contact for one of the largest investor owned utilities in the northeast US.

Manager – Project Management and Controls (2015-2016)

Spearheaded project management initiatives. Directed and led a team of six professional individuals that managed various size projects. Served as the Storm/Emergency Response Management Lead.

- Ensured safe and profitable execution of a \$50M project portfolio for investor-owned utilities.
- Developed project controls, metrics, resource planning and backlog reporting within the Utility Services division.
- Implemented a standard process for responding to customers' resource requests during storms and emergencies. Improved company's response time by 25%.
- Single point of contact for one of the largest investor-owned utilities in the northeast US.

PPL Electric Utilities, Corp., Allentown, PA

July 2002 - January 2015

Manager – Distribution Portfolio Management (2012-2015)

Managed a portfolio of \$350M capital improvement projects, maintenance programs, and service work within the company's distribution and substation system.

- Improved the budget planning and monitoring process through improved proactive reporting and analysis.
- Developed and maintained an internal and external labor resource strategy for work related to distribution, transmission, metering, and substation work.
- Maintained all Work Management reporting and metrics to ensure adherence to current work management processes. Recommended and facilitated Work Management process improvement opportunities.
- Implemented the company's Distribution System Improvements Charge process (Act 11). Developed all required reporting and analysis for the PA Public Utility Commission (PUC) to support the rate structure as supporting general rate case filings.
- Provided direction and leadership to a team of six professional individuals that developed the annual work plan, work scope adherence, detailed budget variance analysis, monthly forecasting, unit rate analysis, and resource planning.

Program Manager – Advanced Metering Development (2010-2012)

Responsible for managing a \$37 million project to pilot and test advanced metering technology. Piloted the ability of the company's metering system to integrate into multiple business processes and computer systems.

- Worked closely with the PA Public Utility Commission (PUC) to ensure the company was meeting all requirements of Act 129 including bi-annual stakeholder meetings and annual status update filings.
- Provided direction and leadership to a team of three professional individuals.

Key Account Manager (2008-2010)

Serve as single point of contact for 200 key business accounts in the Lehigh Valley.

- Collaborated with internal resources to ensure the needs of Key Accounts are met in an effective, efficient and timely manner.
- Developed a communication plan and strategy for transitioning business customers into new tariff rate structures after years of rate caps.
- Maintained a strong knowledge of electric issues, tariffs, rates and service requirements.

Functional Requirements Lead – Mobile Operations Management (2007-2008)

Responsible for identifying, documenting and testing functional business requirements for the Mobile Workforce Management application. Deployed approximately 350 laptops to the field workforce.

- On-time and successful implementation of the first phase of the project (software vendor selection, hardware selection, testing and deployment).

Support Engineer – Distribution Asset Management (2004-2007)

Analyzed the need for distribution system reinforcements and developed large capital projects to support the need. Performed system studies for the connection of customers and non-utility generators. Evaluated and recommended changes in methods, design, and equipment

- Streamlined the process for connecting non-utility generators to the company's distribution system.
- Developed improved method for tracking non-utility generators connected to the system.

Engineer – Asset Maintenance & Reliability (2002-2004)

Provided statistical and technical analysis to develop budget requirements for maintenance programs

- Developed and managed an Underground Cable Replacement Program.
- Created a process for responding to emergency fiber optic network issues.
- Published quarterly reliability reports to the Pennsylvania Public Utility Commission (PUC).

Cooperative Associate – Transmission Engineering (Summer 2001)

Supported Transmission Design Engineers with various projects. Prepared estimates on future transmission projects. Supported Siting Coordinator in writing PA PUC reports for new transmission lines.

EDUCATION AND CERTIFICATION

Master of Business Administration, Supply Chain Management Concentration, 2009

LEHIGH UNIVERSITY, Bethlehem, PA

Professional Engineer, 2008

Power Technology Certificate, 2005

SIEMENS, Schenectady, NY

Bachelor of Science in Electrical Engineering, Business Minor, 2002

VILLANOVA UNIVERSITY, Villanova, PA

COMMUNITY ENGAGEMENT

Trustee, Da Vinci Science Center, 2024 – Present

Volunteer/Committee Member, YWCA Perfect Fit, 2024 – Present

Campaign Champion, United Way Lehigh Valley, 2024 - Present

Volunteer, Meals on Wheels Driver, 2021 - present

UGI GAS STATEMENT NO. 4

VIVIAN K. RESSLER

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 4

**Direct Testimony of
Vivian K. Ressler**

Topics Addressed:

**Budgeting Process
Operating Expense Adjustments
Capital Treatment of Certain
Information Technology Costs**

Dated: January 28, 2026

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania
4 17517.

5
6 **Q. By whom are you employed and in what capacity?**

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

12
13 **Q. What are your responsibilities as Director – Utility FP&A?**

14 A. I have responsibility for UGI’s financial budgeting, forecasting and analysis processes. I
15 lead a team of analysts responsible for preparing the annual budget, including obtaining
16 input from operational departments throughout the business. The team also performs
17 analysis of budget to actual variances and completes financial forecasting and modeling to
18 support business decisions. My duties also include the coordination of these functions with
19 UGI’s Accounting Department and the UGI Corp. Sr. Director of FP&A as well as finance
20 and accounting personnel at UGI Corp.

21
22 **Q. Please describe your educational background and work experience.**

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

1 **Q. Have you testified previously before this Commission?**

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

3

4 **Q. What is the purpose of your testimony?**

5 A. I am providing testimony on behalf of UGI Gas in support of the Company's rate case
6 budgeting methodology and certain operating expense adjustments. First, I will discuss
7 the budgeting process used by UGI Gas (Section II). Next, I will discuss certain operating
8 expense adjustments (Section III). Finally, I will discuss the Company's accounting for
9 certain Information Technology ("IT") costs (Section IV).

10

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

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

17

18 **II. BUDGETING PROCESS**

19 **Q. Please provide a high-level summary of UGI Gas's budgetary preparation and**
20 **approval process.**

21 A. UGI Gas's fiscal year begins on October 1 and ends on September 30 of the following year.
22 Preparation of the UGI Gas Operating Budget for the subsequent two fiscal years begins
23 during the spring, *i.e.*, the budget process for the October 1, 2025 through September 30,
24 2026 fiscal year (Fiscal 2026) and the October 1, 2026 through September 30, 2027 fiscal

1 year (Fiscal 2027) begins in the spring of 2025, with information being requested and
2 incorporated from all departments. This allows UGI Gas to utilize the budget as a starting
3 point for its FPFTY rate claim. Internal reviews and revisions occur throughout the spring
4 and summer before the final budget for UGI Corp. is approved by the UGI Corp. Board of
5 Directors in September – immediately prior to implementing the budget. I provide further
6 detail regarding the preparation of the “Operating” and “Capital” Budgets below.

7
8 **Q. Please describe how the Operating Budget is prepared.**

9 A. As an initial matter, I note that the Operating Budget has both a revenue and expense
10 component, which I will discuss in turn. In addition, each element of the UGI Gas
11 Operating Budget is formulated by personnel with responsibilities specific to each aspect
12 of the operation. The first and primary use of the Operating Budget is as a working tool
13 for the management and planning of the business.

14 The revenue portion of the budget is a joint effort between the Marketing and FP&A
15 departments. The Marketing department provides customer growth and attrition
16 information by customer class along with specific large commercial and industrial sales,
17 and revenue budget projections. The number of customers by customer class is determined
18 using a wide range of factors, including trends in usage, the level of applications and
19 inquiries for service from existing customers, new construction, and shifts in type of
20 residence and customer mix. Budgeted usage per customer is developed by application of
21 a two-year regression to historic data and incorporates normal weather on a 10-year basis
22 (with such normal weather period being as defined by UGI Corp. for use in the budget
23 process). The budgeted number of customers and usage per customer are combined to

1 produce monthly budgeted sales. The revenue budget is calculated by applying appropriate
2 rates for each customer class to budgeted sales volumes, plus an adjustment for unbilled
3 revenue. The sales and revenue budget is then reviewed with and approved by senior
4 management. Normalizing and annualizing ratemaking adjustments to the budget for
5 presentation of the FPFTY sales and revenue in this filing are discussed in the direct
6 testimony of UGI Gas witness Sherry A. Epler (UGI Gas Statement No. 10).

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

20 The final Operating Budget is then submitted to UGI's President for review and
21 approval. After this approval, the UGI budget is submitted to the Chief Financial Officer
22 at UGI Corp. for additional review and approval and is consolidated with the budgets of
23 other operating units of UGI Corp. The President of each UGI Corp. business unit reviews

1 his or her budget with the UGI Corp. Board of Directors and then the UGI Corp. Board of
2 Directors approves the consolidated UGI Corp budget.

3
4 **Q. Please describe how the Capital Budget is prepared.**

5 A. In order to prepare the Capital Budget, operating personnel in each functional area prepare
6 a detailed list of capital projects. Each project is identified, described, and justified along
7 with a breakdown of the costs associated with it. These projects are presented to senior
8 management, which reviews them in terms of priority, capital availability, and strategic
9 alignment with the operating budget. After due consideration, the Capital Budget is set
10 and presented, along with the Operating Budget, to senior management in a series of review
11 meetings. This Capital Budget is subject to approval by the UGI Corp. Board of Directors
12 in a manner similar to that described above for the Operating Budget. Additional
13 information concerning the factors considered in establishing the UGI Gas Capital Budget
14 is provided in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 7).

15
16 **Q. Please explain how expenses from affiliated companies are treated to develop the
17 budgeted Statement of Operations.**

18 A. UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies,
19 in accordance with affiliated interest arrangements authorized by the Commission. UGI
20 also allocates or assigns applicable costs between UGI Electric and UGI Gas. Costs that
21 can be identified as pertaining exclusively to an operating unit are billed directly to that
22 unit. Those costs that cannot be directly associated with the operation of an individual
23 operating unit are allocated to the various companies benefiting from the service.

1 Allocations are made by using a methodology applicable to the cost (*e.g.*, budgeted time
2 allocations, number of employees, etc.) or, if no one methodology is specific to the cost,
3 by using a formula referred to as the Modified Wisconsin Formula (“MWF”) or another
4 reasonable allocation methodology. The MWF or other allocation methodology achieves
5 a reasonable distribution of common expenses based on the relative activity and size of
6 each operating unit to the total of all operating units which benefit from the respective
7 activities. Activity is measured by revenues and operating and maintenance (“O&M”)
8 expenses. Size is measured by tangible net assets employed (excluding acquisition
9 goodwill) or by gross plant balance.

10
11 **Q. How is the budget information used to support UGI Gas’s requested revenue**
12 **increase?**

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

17
18 **III. OPERATING EXPENSE ADJUSTMENTS**

19 **Q. Please describe how the Company’s claimed operating expenses were determined.**

20 A. As discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2),
21 the *pro forma* FPFTY expenses were based on the budgeted level of expenses as a starting
22 point. This budgeted level of expenses was then adjusted to comply with Commission
23 precedent and generally accepted ratemaking principles to reflect a normal, ongoing level
24 of operations. The supporting schedules for those adjustments are found in UGI Gas

1 Exhibit A (Fully Projected), Section D. Below, I will discuss the specific operating
2 adjustments that I am sponsoring, as contained in UGI Gas Exhibit A (Fully Projected),
3 Section D.

4
5 **1. Uncollectible Accounts Expense**

6 **Q. Please explain the adjustment shown on Schedule D-11 for Uncollectible Accounts**
7 **Expense.**

8 A. This adjustment, (\$0.330) million (line 8, column 5), adjusts budgeted uncollectible
9 accounts expense to reflect a three-year average rate of uncollectible accounts expense to
10 tariff revenue for Fiscal Years 2023, 2024, and 2025.

11 The amount of uncollectible expense in the budget is adjusted utilizing the three-
12 year average uncollectible rate of 1.723 percent (line 4, column 5). The 1.723 percent is
13 applied to the *pro forma* revenues at present rates (line 6, column 3) to calculate the *pro*
14 *forma* uncollectible accounts expense of \$21.139 million (line 7, column 4). This results
15 in a decrease in the level of uncollectible accounts expense for the FPFTY from the
16 budgeted amount of \$21.469 million (line 5). The 1.723 percent uncollectible rate is then
17 applied to determine the level of uncollectible accounts expense at *pro forma* proposed
18 rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule
19 D-35.

20
21 **2. Injuries and Damages Adjustment**

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

23 A. The amount of expense incurred for injuries and damages in any one year can vary based
24 on the quantity and severity of the claims. The Company bases its claim for injuries and

1 damages on a normalized amount. This is accomplished by making an adjustment on this
2 schedule for the difference between the normalized amount and the budgeted amount. The
3 three-year average of injuries and damages expenses of \$1.863 million is calculated on
4 lines 1 – 4 of Schedule D-15. The budgeted amount for injuries and damages, \$0.987
5 million, is shown on line 5. The difference between these amounts, \$0.876 million, was
6 used to adjust budgeted injuries and damages expense, as shown on line 6, to reflect the
7 normalized expense.

8 9 **3. Customer Accounts Expense Adjustment**

10 **Q. Please discuss the adjustment for Customer Accounts Expense shown on Schedule D-**
11 **15.**

12 A. This adjustment includes a component to recover interest on customer deposits. The
13 Company is required to pay interest on customer deposits that it holds in accordance with
14 its tariff requirements. As this is a typical business expense, the Company has added this
15 amount to its expense claim that is otherwise not reflected in the Operations Budget. It is
16 calculated by using the average level of customer deposits anticipated for the FPFTY (*i.e.*,
17 \$23.197 million) times the required interest rate (7.0 percent) anticipated for the FPFTY,
18 as published by the Pennsylvania Department of Revenue and as required under the
19 Company's tariff. The total interest on customer deposits, an amount of \$1.624 million,
20 is shown on line 7.

1 **4. PUC Assessment**

2 **Q. Please discuss the adjustment for PUC assessment shown on Schedule D-15.**

3 A. This adjustment reflects the difference between the budgeted PUC assessment expense
4 (\$5.131 million on line 9) and the projected annual PUC assessment expense as of
5 September 30, 2027 (\$6.006 million on line 8). This adjustment of \$0.875 million (line
6 10) is necessary to (1) adjust from the budget timing (October through September) to the
7 timing of the PUC assessment (July through June); and (2) update the projection amount
8 based on the most recent PUC assessment invoice (which was received subsequent to
9 completion of the Company’s budget).

10
11 **IV. CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY**
12 **COSTS**

13 **Q. What is the Company’s policy for capital treatment of IT costs?**

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

1 implementation support following the deployment of an IT project to ensure that the newly
2 implemented system operates as planned.

3

4 **Q. Is the Company planning to continue with similar methods of IT cost capitalization**
5 **in this proceeding?**

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

10

11 **Q. Does this conclude your direct testimony?**

12 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
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Trout, Ebersole & Groff, LLP – Lancaster, PA

May 2012 – May 2014	Supervisor – Attest Services
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BI-LO, LLC – Greenville, SC

Nov. 2007 – May 2012	Sr. Manager – Corporate Accounting & Tax
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Deloitte & Touche, LLP – Greenville, SC

Sept. 1998 – Oct. 2007	Staff Accountant through Sr. Manager – Audit Services
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Previous Testimony before the Pennsylvania Public Utility Commission

UGI Gas Base Rate Case	Docket No. R-2019-3015162
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UGI Electric Base Rate Case	Docket No. R-2021-3023618
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UGI Gas Base Rate Case	Docket No. R-2021-3030218
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UGI Electric Base Rate Case	Docket No. R-2022-3037368
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UGI Gas Base Rate Case	Docket No. R-2024-3052716
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Education & Professional Certification

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

Certified Public Accountant – Commonwealth of Pennsylvania

UGI GAS STATEMENT NO. 5

AMY M. KELLER

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 5

**Direct Testimony of
Amy M. Keller**

Topics Addressed: **Accounting Process and Historic Costs**
Fully Projected Future Test Year
Rate Base
Operating Expense Adjustments

Dated: January 28, 2026

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Amy M. Keller. My business address is 1 UGI Drive, Denver, Pennsylvania
4 17517.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed by UGI Utilities, Inc. (“UGI”) as Senior Manager, Regulatory and Plant
8 Accounting. UGI is a wholly-owned subsidiary of UGI Corporation (“UGI Corp.”). UGI
9 has two operating divisions, the Gas Division (“UGI Gas” or the “Company”) and the
10 Electric Division (“UGI Electric”), each of which is a public utility regulated by the
11 Pennsylvania Public Utility Commission (“Commission” or “PUC”).

12
13 **Q. What are your responsibilities as Senior Manager, Regulatory and Plant Accounting?**

14 A. I have responsibility for UGI’s plant accounting and regulatory accounting processes. I
15 lead a team of accountants responsible for maintaining complete and accurate plant
16 accounting records, and for preparing and submitting certain regulatory filings with the
17 PUC and Federal Energy Regulatory Commission (“FERC”). My duties also include the
18 coordination of these functions with UGI’s Assistant Controller as well as financial
19 accounting and reporting personnel and UGI Corp.

20
21 **Q. Please describe your educational background and work experience.**

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

1 **Q. Have you testified previously before this Commission?**

2 A. No, I have not.

3

4 **Q. What is the purpose of your testimony?**

5 A. I am providing testimony on behalf of UGI Gas in support of the Company's rate case
6 accounting methodology and certain operating expense adjustments. First, I will explain
7 UGI Gas's accounting processes, which were used to develop the actual book accounting
8 results, which are the basis for the Company's historic test year ended September 30, 2025
9 ("HTY") (Section I).¹

10

11 **Q. Ms. Keller, are you sponsoring any exhibits in this proceeding?**

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

18

19 **II. ACCOUNTING PROCESS AND HISTORIC COSTS**

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

21 A. The accounting records of UGI Gas are kept in accordance with generally accepted
22 accounting principles ("GAAP") and the Federal Energy Regulatory Commission's

¹ The budgets for the future test year ending September 30, 2026 ("FTY") and the FPFTY are discussed in the Direct Testimony of Tracy A. Hazenstab (UGI Gas St. No. 2).

1 (“FERC”) Uniform System of Accounts (“USOA”) as required under the provisions of 52
2 Pa. Code § 59.42. The Company also maintains a continuing property records system in
3 accordance with the requirements of 52 Pa. Code § 59.46.
4

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

6 A. Yes. The books and records of UGI Gas are audited by its internal auditors. In addition,
7 UGI Gas’s books and records are included in Company-wide audits of UGI, performed by
8 its external auditor, KPMG, LLP. The Company’s books and records are further subject
9 to audit by the PUC.
10

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

13 A. Yes, they do. UGI Gas’s plant in service, plant additions, retirements, and book
14 adjustments have been recorded on an original cost basis in accordance with GAAP and
15 the USOA requirements.
16

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

19 A. UGI Gas’s capital project managers create records that document the costs of projects
20 and/or asset purchases. When a capital project or asset is placed into service, the project
21 manager records the in-service date and the retirement detail for any related assets that are
22 taken out of service. Then, the record is provided to accounting personnel. This
23 information is transferred through accounting entries into the appropriate UGI Gas plant

1 property accounts, subject to review by authorized individuals who approve the entries and
2 further review by internal and external auditors.

3
4 **Q How was the Company’s accounting process used in preparing the Company’s filing?**

5 A. The above-described accounting process was used to prepare the principal accounting
6 exhibits that support UGI Gas’s claim in this proceeding. As discussed in the direct
7 testimony of Company witnesses Hans G. Bell (UGI Gas Statement No. 1) and Tracy A.
8 Hazenstab (UGI Gas Statement No. 2), the Company’s claim is based on the FPFTY. The
9 accounting data for the FPFTY was derived from UGI Gas’s Operating and Capital
10 Budgets for the 12 months ending September 30, 2027, as shown in UGI Gas Exhibit A
11 (Fully Projected). The accounting data for the FTY was derived from UGI Gas’s Operating
12 and Capital Budgets for the 12 months ending September 30, 2026, as shown in UGI Gas
13 Exhibit A (Future). The accounting data for the HTY was derived from UGI Gas’s books
14 and records for the 12 months ended September 30, 2025, as shown in UGI Gas Exhibit A
15 (Historic).

16
17 **III. FULLY PROJECTED FUTURE TEST YEAR RATE BASE**

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

20 A. UGI Gas’s rate base presentation is shown in UGI Gas Exhibit A (Fully Projected),
21 Schedule C-1. It summarizes the UGI Gas rate base values for the FPFTY. Column 1
22 provides the schedule where the calculations of each of the rate base elements are found.
23 Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas’s
24 total FPFTY rate base claim—net of deductions for accumulated depreciation,

1 accumulated deferred income taxes and customer deposits—is \$4.319 billion. Except
2 where otherwise noted, I will describe each of the rate base elements in greater detail
3 below.

4
5 **1. Utility Plant in Service**

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

8 A. UGI Gas’s claim for FPFTY rate base value for net plant in service is the sum of the gross
9 utility plant in service claim and the accumulated depreciation claim as of September 30,
10 2027, as described below.

11 Gross utility plant in service represents the sum of the closing plant balances as of
12 September 30, 2025, plus budgeted additions placed in service for the years ending
13 September 30, 2026, and September 30, 2027, less expected FTY and FPFTY plant
14 retirements. The direct testimony of Company witness Vicky A Schappell (UGI Gas
15 Statement No. 7) discusses the capital addition planning process and the basis for the
16 additions placed in service in the FTY and FPFTY.

17 UGI Gas’s claim also reflects a reduction for accumulated depreciation, which is
18 based on the closing accumulated depreciation balances as of September 30, 2025, plus
19 depreciation expenses for the years ending September 30, 2026, and September 30, 2027,
20 less expected FTY and FPFTY plant retirements.

21
22 **Q. Please describe Schedule C-2 to UGI Gas Exhibit A (Fully Projected).**

23 A. This schedule presents UGI Gas’s FPFTY claim of \$6.677 billion for used and useful gas
24 gross utility plant in service on page 2, column 2, line 64. That amount is also reflected on

1 line 1 of the measure of value summary on Schedule C-1. Gas utility plant enables UGI
2 Gas to provide safe and reliable gas service to its customers.

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

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

9
10 **Q. What information is included on Schedule C-2, pages 4 and 5?**

11 A. Columns 2 and 3 on these pages show the gas plant in service balances for 2026 and 2027
12 at the FERC account level, based on the placed in service budget. Column 5 provides the
13 ending FPFTY plant balance at the FERC account level.

14
15 **Q. Where are plant in service additions shown?**

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

19
20 **Q. Where are plant retirements shown and how were these retirements projected for
21 the FTY and the FPFTY?**

22 A. Pages 8 and 9 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY
23 and FPFTY) plant retirements. Retirements for most plant accounts were projected by

1 plant account. The Company applied the average retirement rate, as a percent of additions,
2 for the five fiscal years 2021 through 2025, to the FPFTY and FTY plant in service
3 additions. For certain plant accounts subject to amortization accounting, retirements are
4 recorded when a vintage is fully amortized. For these accounts, all units are retired when
5 the vintage is fully amortized.

6 7 **2. Accumulated Depreciation**

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

10 A. UGI Gas started with accumulated depreciation as of September 30, 2025, added the
11 budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact
12 of the FTY and FPFTY plant retirements and a provision for net salvage as shown on
13 Schedule C-3. The depreciation rates and test year expense levels are discussed in the
14 direct testimony of John F. Weidmayer (UGI Gas Statement No. 6), with the underlying
15 FPFTY depreciation analysis provided in UGI Gas Exhibit A (Fully Projected).

16
17 **Q. Please describe UGI Gas's accumulated depreciation claim.**

18 A. UGI Gas's accumulated depreciation claim is shown on Schedule C-3 of UGI Gas Exhibit
19 A (Fully Projected). This schedule presents the accumulated provision for depreciation as
20 of September 30, 2027, distributed among the various FERC accounts. The total amount
21 for accumulated depreciation, \$1.736 billion, is summarized on page 2, column 2, line 64,
22 of this schedule. That amount is reflected on line 2 of the measure of value summary on
23 Schedule C-1 as a reduction to rate base.

1 Page 3 of Schedule C-3 shows the *pro forma* FPFTY level of accumulated
2 depreciation distributed to the various plant categories. Pages 4 and 5 show the details of
3 the accumulated depreciation by FERC account for Fiscal Years 2026 (column 2) and 2027
4 (column 3) based on budget plus adjustments (column 4), if any, to arrive at the FPFTY
5 balance (column 5). Pages 6 and 7 show the cost of removal by FERC account and pages
6 8 and 9 show negative net salvage amortization by FERC account. Pages 10 and 11 include
7 the salvage amounts by FERC account. These amounts are included in the FPFTY
8 accumulated depreciation calculations. The amortization of negative net salvage was
9 calculated using a 5-year amortization schedule in accordance with Commission precedent.
10

11 **Q. Please summarize UGI Gas’s net in plant in service claim.**

12 A. UGI Gas’s net plant in service claim reflects *pro forma* gross utility plant as described
13 above of \$6.677 billion at September 30, 2027, less *pro forma* accumulated depreciation
14 of \$1.736 billion at September 30, 2027. These amounts are both reflected in the measure
15 of value summary on Schedule C-1.
16

17 **3. Cash Working Capital**

18 **Q. Please explain how UGI Gas determined its rate base value for cash working capital**
19 **(“CWC”).**

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

1 **Q. Where is the CWC rate base value summarized?**

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

5
6 **Q. What data is shown on page 2 of Schedule C-4?**

7 A. Page 2 summarizes the derivation of UGI Gas's revenue collection lag and overall expense
8 payment lag. The revenue lag is 57.46 days (line 1). Expense lag days include three
9 categories of annual operating expenses: (1) payroll; (2) purchased gas costs; and (3) other
10 expenses. The expense lag days are shown for each component (lines 3-5), which amount
11 to 27.55 days (line 7). The net lag in the collection of revenue is 29.91 days (line 8). This
12 number is then multiplied by the average daily operating expense balance (line 9) to arrive
13 at a base CWC amount for Operations and Maintenance ("O&M") expense of \$57.012
14 million (line 10). The average daily expense balance of \$1.906 million (line 9) is
15 determined by dividing the total *pro forma* annual operating expenses, excluding
16 uncollectible accounts expense, of \$695.601 million (line 6, column 2), by the number of
17 days in the year, or 365. I will describe the other components of the CWC claim when I
18 discuss the related schedules.

19

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

21 A. The Company's calculation for the total revenue lag days of 57.46 (line 23) consists of
22 several steps. First, the annual revenue (line 18, column 3) is divided by the average
23 month-end accounts receivable balances for the 13 months ended September 30, 2025 (line

1 17, column 2). This results in an accounts receivable turnover rate of 9.14 (line 19, column
2 4), which is equivalent to 39.93 lag days (line 20, column 5) (i.e., 365 divided by 9.14
3 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the
4 revenue lag is added to: (1) the 2.32-day lag between the meter reading day and the day
5 bills are sent out and recorded as revenue and accounts receivable by the Company
6 (appearing on line 21); and (2) the 15.21-day service lag (i.e., midpoint lag factor), which
7 is the time from the mid-point of the service period until the meter reading date (appearing
8 on line 22). This calculation results in a total revenue lag of 57.46 days.

9
10 **Q. How was the mid-point of the service period calculated?**

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

13
14 **Q. How are the payroll expense lag days for the CWC claim calculated?**

15 A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown
16 there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods
17 for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-
18 2, with the same bi-weekly pay period. The lag days are calculated based on 14 days in the
19 pay period divided by 2 (for an average), with a 5-day payroll processing time period
20 added, resulting in a 12-day lag period.

1 **Q. How were the lag days associated with the purchased gas costs shown on Schedule C-**
2 **4, page 4, line 8, calculated?**

3 A. This calculation is shown on page 6 of Schedule C-4 and is based on a review of gas
4 purchases during the 12-month period of October 2024 through September 2025. The total
5 dollar amount of gas purchased during this period was \$505.975 million (on line 13,
6 column 2). The average payment lag was calculated by dividing the total dollar days for
7 purchased gas costs (\$13.199 billion) by the total dollar amount of gas purchased (\$505.975
8 million), which equals 26.09 days (on line 14). The payment lag was determined using the
9 midpoint of the service period for each of the payments and the payment date for each,
10 averaged over the 12-month study period. The 26.09-day lag for purchased gas costs is
11 then brought forward to Schedule C-4, page 4, line 8, and Schedule C-4, page 2, column 3,
12 line 4.

13
14 **Q. What are dollar days, and how were they used in the CWC calculation?**

15 A. Dollar days are the product of a payment amount multiplied by the number of days between
16 the invoice date or service date and the date that the payment clears the Company's bank.
17 The dollar days calculation is used to calculate a weighted average number of lag days for
18 both purchased gas costs (Schedule C-4, page 6) and general disbursements (Schedule C-
19 4, page 5).

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

3 A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all
4 remaining expenses was derived from data over the HTY, as shown in more detail on page
5 5 of Schedule C-4. A summary list of all cash disbursements, including the invoice date,
6 the amount of the disbursement, the date the payment was made, and the type of
7 disbursement (for capital, commodity, or expense), during each of these months was used.
8 As shown on page 5, lines 1-24, columns 1 and 2, each month's listing contained numerous
9 cash disbursements. Once the raw payment data was assembled, the dollar days for
10 expense purchases were determined by multiplying the amount of the disbursement by
11 either (i) the number of days from invoice date until bank clearance for wire and Automated
12 Clearing House ("ACH") payments, or (ii) the number of days from the invoice date until
13 check date, plus seven days (representing mail lag) for payments made by check.
14 Disbursements were eliminated if they were included in another calculation (e.g., gas
15 purchases) or were paid for capital items. After these adjustments, the average of the
16 expense lag days for each month shown on Schedule C-4, page 5, column 4, line 25,
17 resulted in a payment lag for general disbursements of 36.55 days. The lag for other
18 disbursements is then brought forward to Schedule C-4, page 4, line 22 and Schedule C-4,
19 page 2, column 3, line 5.

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

3 A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation
4 measures the lag associated with the payment of interest on outstanding debt. The *pro*
5 *forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest
6 expense of \$0.280 million shown on page 7, line 5. That amount is then multiplied by the
7 net payment lag, resulting in a reduction to the working capital allowance of \$9.459 million
8 as shown on page 7, line 9 of Schedule C-4. This amount is then included on page 1, line
9 2 of Schedule C-4.

10

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

13 A. This calculation is shown on page 8 of Schedule C-4. Separate tax payment lag calculations
14 (for working capital) are made for federal income tax, state income tax, PA Property Tax,
15 and the Public Utility Realty Tax Act (“PURTA”). Each of these calculations is based on
16 anticipated FPFTY tax payments and an April 1 mid-point of annual service. The results
17 for each of these components are shown and summed in column 10 to derive the net
18 working capital allowance for tax payments of \$4.570 million shown on page 8, line 19.
19 This amount is then included on page 1, line 3 of Schedule C-4.

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

3 A. That amount is calculated on page 9 of Schedule C-4 and represents the 13-month average
4 of actual pre-paid amounts for each month ended from September 2024 through September
5 2025. The 13-month average of total actual pre-paid amounts during that period is \$14.400
6 million, shown on page 9, line 18. This amount is then included on page 1, line 4 of
7 Schedule C-4.

8
9 **Q. What is the total amount of the Company's CWC claim?**

10 A. UGI Gas's claim for CWC is \$66.523 million. This amount is shown on Schedule C-4,
11 page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

12

13 **4. Gas Storage Inventory**

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

15 A. Gas storage inventory represents gas volumes stored in facilities or in storage fields owned
16 by interstate pipeline or storage companies with whom UGI Gas contracts for capacity. As
17 is typical for most natural gas distribution systems, UGI Gas purchases storage gas
18 throughout the year for use primarily during the winter heating season. Specifically, the
19 Company pays its gas storage bills on a monthly basis once the gas is procured in the same
20 way that it pays for gas procured from other sources. Storage inventory is a physical asset
21 that is included in the Company's rate base claim in the same manner as materials and
22 supplies inventory. UGI Gas's claim for gas storage inventory is based on a 13-month
23 average book value for the period ending September 2025, as shown on Schedule C-5. The
24 average monthly gas inventory balance for the FPFTY is \$23.662 million, as shown on

1 Schedule C-5, line 16. This amount is also used in Schedule C-1, line 5 and Schedule A-
2 1, line 5.

3
4 **5. Accumulated Deferred Income Taxes**

5 **Q. Please explain how the rate base value for Accumulated Deferred Income Taxes**
6 **(“ADIT”), including Excess Deferred Federal Income Taxes (“EDFIT”), was**
7 **calculated.**

8 A. The Company’s determination of its rate base value for ADIT, including EDFIT, is shown
9 on Schedule C-6 and is discussed in the direct testimony of Darin T. Espigh (UGI Gas
10 Statement No. 9). This amount of \$716.793 million reduces the rate base. This amount is
11 also used in Schedule C-1, line 6 and Schedule A-1, line 6.

12
13 **6. Customer Deposits**

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

15 A. Customer deposits offset the need for UGI Gas to provide capital. UGI Gas’s claimed
16 offset for customer deposits is based on the average customer deposit balance for the 13-
17 month period ending September 2025, as shown on Schedule C-7.

18
19 **Q. What is the amount of the rate base offset for customer deposits?**

20 A. The customer deposit offset is \$23.197 million, as shown on Schedule C-7, line 16,
21 Schedule C-1, line 7, and on Schedule A-1, line 7.

1 **7. Materials and Supplies Inventory**

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

3 A. UGI Gas maintains various materials and supplies in inventory for use in its operations.
4 The Company’s claim for materials and supplies inventory is \$28.644 million, as shown
5 on Schedule C-8, line 16, Schedule C-1, line 8, and on Schedule A-1, line 8. This amount
6 is based on the average inventory for the 13-month period ending September 30, 2025, as
7 shown on Schedule C-8.

8
9 **IV. OPERATING EXPENSE ADJUSTMENTS**

10 **Q. Please describe how the Company’s claimed operating expenses were determined.**

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

19
20 **1. Environmental Remediation Expenses**

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

22 A. Consistent with the methodology the Company has used in past rate cases, the two
23 adjustments shown on Schedule D-8 are designed to reconcile past Environmental
24 Remediation expense rate recoveries with actual incurred costs and to recover a projected

1 annual level of Environmental Remediation expense. These costs are incurred in
2 connection with UGI Gas’s obligations under a Consent Order Agreement (“COA”) with
3 the Pennsylvania Department of Environmental Protection (“DEP”).² The Company’s
4 remediation activities under the COA are discussed in the direct testimony of Jill E. Walter
5 (UGI Gas Statement No. 3).

6
7 **Q. Please describe the first Environmental Remediation expense adjustment shown on**
8 **Schedule D-8.**

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

16 The average of the last three years of cash expenditures for remediation expenses
17 under the COA is \$6.698 million and represents the amount that the Company anticipates
18 it will spend in the FPFTY under the COA. The difference between this annual amount
19 (\$6.698 million) and the amount budgeted by the Company (\$5.429 million), or \$1.269
20 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.

1 **Q. Please describe the second Environmental Remediation expense adjustment shown**
2 **on Schedules D-8, lines 7-13.**

3 A. The second environmental adjustment (on lines 7-13 on Schedule D-8) shows the net
4 under-recovery of the Company's MGP remediation expense incurred in past years, and
5 the planned amortization for this net under-recovery. This net under-recovery resulted
6 from the combination of (1) the under-recovery in actual annual remediation costs for
7 Fiscal 2025 versus the normalized level authorized in the 2025 Gas Rate Case at Docket
8 No. R-2024-3052716 and (2) over-recovery of reconciliation amounts from years prior to
9 Fiscal 2025 (projected through Fiscal 2026). Please use the detailed calculations of this
10 net over-recovery at UGI Exhibit AMK-2.

11 The under-recovered expenditures of \$0.967 million (line 9) will be charged to
12 customers over a two-year amortization period through Fiscal Year 2028, at an amount of
13 \$0.483 million per year (line 11). This two-year amortization period is consistent with the
14 period approved in the settlement of the prior rate case at Docket No. R-2024-3052716.
15 This amount is compared to the budget amount of \$0.610 million of income per year,
16 resulting in a budget adjustment of \$1.093 million (line 13).

17

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

19 A. The adjustment shown on Schedule D-14 reflects an adjustment from budgeted pension
20 expenses to reflect cash to be contributed to the plan in the FPFTY. The Company's budget
21 reflects pension expenses based on GAAP requirements to reflect service and non-service
22 costs based on certain assumptions. However, consistent with prior ratemaking practices,
23 the Company claims pension costs within its rates on a cash basis. The adjustment is

1 calculated as the total cash contributions (as provided by the Company's actuary in the
2 most recent actuarial report), reduced to reflect only the portion attributable to UGI Gas,
3 and then further reduced to reflect the portion of pensions that is capitalizable. This cash
4 pension expense of \$4.507 million (line 5) is compared to the budgeted pension expense
5 of \$1.437 million (line 1), also calculated for UGI Gas only and net of the capitalizable
6 portion, resulting in an adjustment of \$3.071 million (line 6).

7

8 **Q. Does this conclude your direct testimony?**

9 **A. Yes, it does.**

UGI GAS

EXHIBIT AMK-1

Amy M. Keller

Senior Manager – Regulatory and Plant Accounting

Work Experience

- UGI Utilities, Inc. – Denver, PA
 - Oct. 2025 – Current Senior Manager – Regulatory and Plant Accounting
 - Dec. 2021 – Sep. 2024 Manager of Process Improvement
 - Feb. 2020 – Nov. 2021 Manager of General Ledger and Regulatory Accounting
 - Feb. 2018 – Jan. 2020 Manager of Revenue and Supply Accounting
 - May 2016 – Jan. 2018 Supervisor of Revenue Accounting

- Penn National Gaming. – Wyomissing, PA
 - May 2015 – May 2016 Senior Auditor, Internal Audit

- Fulton Financial Corporation – Lancaster, PA
 - Jan. 2013 – May 2015 Senior Auditor, Internal Audit

- Baker Tilly (formerly ParenteBeard, LLC) – Wyomissing, PA
 - Jan. 2010 – Jan. 2013 Intern through Staff Accountant II, Small Business Division

Education & Professional Certification

- B. S. in Accounting – Albright College, Reading, PA
- B. S. in Psychology – Elizabethtown College, Elizabethtown, PA

- Certified Public Accountant – Commonwealth of Pennsylvania

UGI GAS

EXHIBIT AMK-2

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

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

Year(s) to which Under / (Over) Recovery Relates	Docket No. of Rate Case in which Amortization was Mostly Recently Approved	Per month Amortization as approved in docket # R-2021-3030218	Per month Amortization as approved in docket # R-2024-3052716	Under Recovered Balance at 9/30/2025	Amount in Rates by Fiscal Year		Under / (Over) Recovered Balance at 9/30/2026
					FY26 (1)		
FY24 and prior	R-2024-3052716	(252)	51	(1,221)	307	(914)	
Total		(252)	51	(1,221)	307	(914)	Schedule D-8 Line 7
					(1)	(2)	

Under / (Over) Recoveries since Prior Rate Case:

Year(s) to which Under / (Over) Recovery Relates	Spend per fiscal year	Amortized in Rates allowed by rate case		Under / (Over) Recovery	Under / (Over) Recovered Balance at 9/30/2026
FY25	7,052	(5,171)	1,880		1,880
Total	7,052	(5,171)	1,880		1,880
					(2)

Schedule D-8 Line 8

(1) Amount includes one month of prior rate case amortization (rates approved at Docket #R-2021-3030218) and eleven months of the rates approved in the new rates (rates approved at Docket #2024-3052716, effective October 28, 2025).

(2) Amounts are included within Environmental Adjustment #2 at Schedule D-8 of Exhibit A, Fully Projected.

UGI GAS STATEMENT NO. 6

JOHN F. WIEDMAYER

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 6

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

Topics Addressed: Depreciation and Net Salvage

Date: January 28, 2026

TABLE OF CONTENTS

	<u>Page</u>
I. INTRODUCTION.....	1
II. PURPOSE OF TESTIMONY.....	5
III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C (HISTORIC).....	7
IV. THE DEPRECIATION STUDY - OVERVIEW.....	11
V. ORIGINAL COST MEASURE OF VALUE.....	13
VI. THE ACCRUED DEPRECIATION CLAIM.....	13
VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM.....	17
VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE.....	23
IX. THE NET SALVAGE AMORTIZATION CLAIM.....	27

1 DIRECT TESTIMONY OF

2 JOHN F. WIEDMAYER

3 DOCKET NO. R-2025-3059523

4 **I. INTRODUCTION**

5 **Q. Please state your name and address.**

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

8
9 **Q. Are you associated with any firm and in what capacity?**

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

13
14 **Q. How long have you been associated with Gannett Fleming?**

15 A. I have been associated with the firm since I graduated from college in June
16 1986.

17
18 **Q. What is your educational background?**

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

21
22 **Q. Do you belong to any professional societies?**

23 A. Yes. I am a member of the National and Pennsylvania Societies of Professional
24 Engineers and the Society of Depreciation Professionals (“SDP”). In 2005, I

1 served as President of the SDP and was a member of the SDP's Executive
2 Board for the years 2003 through 2007.

3
4 **Q. Do you hold any special certification as a depreciation expert?**

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

9
10 **Q. Please outline your experience in the field of depreciation.**

11 A. I have over 35 years of depreciation experience, which includes expert
12 testimony in numerous cases before 14 regulatory commissions, including the
13 Pennsylvania Public Utility Commission ("PUC" or "Commission").

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

1 depreciation rates to management for its consideration, and supporting such
2 rates before regulatory bodies.

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

14 I assisted in the preparation of depreciation studies for the following
15 organizations in the electric industry: AmerenUE, Arizona Public Service
16 Company, BGE, UGI Utilities, Inc. - Electric Division ("UGI Electric"), Penelec,
17 Metropolitan Edison, ConEdison, ComEd, Orange and Rockland, Rockland
18 Electric, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen
19 Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service
20 Company, Michigan Electric Transmission Company, PECO, Jackson Electric
21 Cooperative Corporation, Houston Lighting and Power, Maritime Electric, Nolin
22 Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the
23 City of Calgary - Electric System.

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

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

12
13 **Q. Have you previously testified on the subject of utility plant depreciation?**

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

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

3 A. Yes. I have completed the following courses conducted by Depreciation
4 Programs, Inc.: “Techniques of Life Analysis,” “Techniques of Salvage and
5 Depreciation Analysis,” “Forecasting Life and Salvage,” “Modeling and Life
6 Analysis Using Simulation,” and “Managing a Depreciation Study.” In 2000, I
7 became an instructor at the SDP’s annual conference lecturing on “Salvage
8 Concepts,” “Depreciation Models,” “Analyzing the Life of Real-World Utility
9 Property – Actuarial Analysis,” “Theoretical Reserve Imbalances and True-Up,”
10 and “Data Requirements for a Depreciation Study.”

11
12 **II. PURPOSE OF TESTIMONY**

13 **Q. What is the purpose of your testimony?**

14 A. My testimony is in support of the depreciation studies conducted under my
15 direction and supervision for the Pennsylvania gas plant of UGI Utilities, Inc. –
16 Gas Division (“UGI Gas” or the “Company”). I was retained by the Company as
17 a depreciation consultant. UGI Gas retained me to determine the book
18 depreciation reserve as of September 30, 2027, to determine the annual
19 depreciation expense to be included as an element of the cost of service, and
20 to testify in support of those two determinations in this proceeding.

21 I am also a sponsoring witness for UGI Gas’s depreciated original cost
22 of gas plant in service included in rate base. My testimony will address my
23 depreciation study, the appropriate depreciation reserve for ratemaking
24 purposes, the original cost measure of value, and the appropriate annual

1 depreciation expense to be included in the ratemaking cost of service as of
2 September 30, 2027.

3
4 **Q. Were you responsible for the preparation of any of the Company's**
5 **responses to the Commission's filing regulations that were filed in**
6 **support of the Company's general rate filing?**

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

8	<u>Item No.</u>	<u>Subject</u>
9	I-A-3	Description of Depreciation Methods and Factors
10		Considered in Arriving at Estimates of Service Life and
11		Dispersion by Account
12		
13	I-A-4	Survivor Curves and Surviving Original Cost Including
14		Related Annual and Accrued Depreciation
15		
16	I-A-5	Comparison of Calculated Reserve vs. Book Reserve
17		
18	I-A-6	Survivor Curves and Annual Accrual Rates
19		
20	I-A-7	Cumulative Depreciated Original Cost by Vintage Year
21		
22	I-A-8	Trended Original Cost Methodology
23		
24	I-A-9	Spot Trended Original Cost
25		
26	I-A-10	Undepreciated Original Cost
27		
28	I-A-11	Cumulative Trended Depreciated Original Cost
29		
30	I-A-17	Net Salvage
31		

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

33 A. Yes. I provided testimony on depreciation matters for the Company in the prior
34 two UGI Penn Natural Gas ("PNG") base rate cases at Docket No. R-2016-
35 2580030 and Docket No. R-2008-2079660, the prior two UGI Central Penn Gas

1 (“CPG”) base rate cases at Docket No. R-2010-2214415 and Docket No. R-
2 2008-2079675 and the five most recent base rate case for UGI Utilities, Inc. –
3 Gas Division at Docket No. R-2015-2518438, Docket No. R-2018-3006814,
4 Docket No. R-2019-3015162, Docket No. R-2021-3030218 and Docket No. R-
5 2024-3052716. Prior to those rate filings, I prepared exhibits for the
6 depreciation study in UGI Gas’s base rate case filed in 1995 at Docket No. R-
7 00953297.

8
9 **III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C**
10 **(HISTORIC)**

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

12 A. Yes, I am attaching and sponsoring the following exhibits: UGI Gas Exhibit C
13 (Fully Projected), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Historic).
14 UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation
15 calculations and supporting tables related to the fully projected future test year
16 (“FPFTY”) ending September 30, 2027, for UGI Gas. UGI Gas Exhibit C
17 (Future) presents similar summarized depreciation calculations and supporting
18 charts and tables related to the depreciation study for the future test year (“FTY”)
19 ending September 30, 2026. UGI Gas Exhibit C (Historic) presents the
20 summarized depreciation calculations and supporting tables related to the
21 historic test year (“HTY”) ended September 30, 2025. Each of the three exhibits
22 is organized in a similar manner and contains information and schedules
23 supporting the amounts applicable to each test year period. UGI Gas Exhibit C

1 (Future) contains additional information including the supporting life tables and
2 life table charts related to the service life estimates.

3
4 **Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of
5 your depreciation study as of September 30, 2027?**

6 A. Yes.

7
8 **Q. In preparing the depreciation study, did you follow generally accepted
9 practices in the field of depreciation?**

10 A. Yes.

11
12 **Q. Please describe the contents of the depreciation study reports, UGI Gas
13 Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected).**

14 A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight
15 parts including charts and tables filed in the Company's most recent service life
16 study report prepared by me and submitted in 2023 based on plant accounting
17 data through September 30, 2022. Part I, Introduction, includes statements
18 related to the scope of and basis for the depreciation study. Part II, Estimation
19 of Survivor Curves, presents detailed discussions of: (1) survivor curves; and
20 (2) methods of life analysis, including an example of the retirement rate method.
21 Part III, Service Life Considerations, presents the relevant factors considered
22 for estimating service lives. Part IV, Calculation of Annual and Accrued
23 Depreciation, sets forth a description of: (1) the group procedures used for
24 calculating annual and accrued depreciation; and (2) an explanation of the

1 manner in which net salvage was incorporated in the calculations. Part V,
2 Results of Study, includes a description of the results and summaries of the
3 detailed depreciation calculations as of September 30, 2026. Part VI, Service
4 Life Statistics, presents the results of the retirement rate analyses prepared as
5 the historical bases for the service life estimates. Part VII, Detailed Depreciation
6 Calculations, sets forth the detailed depreciation calculations related to
7 surviving original cost as of September 30, 2026. The detailed depreciation
8 calculations present the annual and accrued depreciation amounts by account
9 and vintage year. The remaining life annual accrual rate is also set forth in the
10 tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains
11 the net salvage amortization of experienced and estimated net salvage for the
12 years 2022 through 2026.

13 UGI Gas Exhibit C (Fully Projected) includes: a description of the scope,
14 basis, and results of the studies; summaries of the depreciation calculations;
15 and the detailed depreciation calculations as of September 30, 2027. The
16 descriptions and explanations presented in UGI Gas Exhibit C (Future) are also
17 applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully
18 Projected). The graphs and tables related to service life presented in UGI Gas
19 Exhibit C (Future) also support the service life estimates used in UGI Gas
20 Exhibit C (Fully Projected) inasmuch as the estimates are the same for all three
21 test years, i.e., HTY, FTY, and FPFTY. The service life estimates set forth in
22 UGI Gas Exhibit C (Historic) are the same estimates as those approved in the
23 Company's Annual Depreciation Report ("ADR") submitted to the PUC in March
24 2025. The pro forma depreciation expense for UGI Gas at the end of the HTY,

1 September 30, 2025, is the sum of the three former rate districts, UGI South,
2 UGI North, and UGI Central.

3 The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully
4 Projected). Table 1, pages II-3 through II-5 of UGI Gas Exhibit C (Fully
5 Projected), presents the estimated survivor curve, the original cost and
6 depreciation reserve as of September 30, 2027, and the calculated annual
7 depreciation rate and amount for each account or subaccount of Gas Plant in
8 Service. Table 2, pages II-6 through II-7 of UGI Gas Exhibit C (Fully Projected),
9 presents the bring-forward to September 30, 2027, of the depreciation reserve
10 as of September 30, 2026. Table 3, pages II-8 through II-9 of UGI Gas Exhibit
11 C (Fully Projected), presents the calculation of the book depreciation amounts
12 for the FPFTY. Table 4, pages II-10 through II-11 of UGI Gas Exhibit C (Fully
13 Projected), presents the experienced and estimated net salvage for fiscal years
14 2023 through 2027. The amortization of net salvage is based on experienced
15 and estimated net salvage during the period October 1, 2022 through
16 September 30, 2027. The summary tables and detailed depreciation
17 calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September
18 30, 2027, are organized and presented in the same manner as those presented
19 in UGI Gas Exhibit C (Future) as of September 30, 2026.

20
21 **Q. Please outline the contents of Exhibit C (Historic).**

22 A. UGI Gas Exhibit C (Historic) is organized similarly to UGI Gas Exhibit C (Fully
23 Projected). UGI Gas Exhibit C (Historic) includes: a description of the scope,
24 basis, and results of the studies; summaries of the depreciation calculations;

1 and the detailed depreciation calculations as of September 30, 2025. The
2 service life estimates used in the HTY period were based on the survivor curve
3 estimates set forth in the ADR submitted to the PUC in March 2025. The same
4 survivor curve estimates were used in each of the three respective test year
5 periods and were based on a service life study submitted to the PUC in 2023
6 using plant accounting data through fiscal year-end 2022. The summary tables
7 and detailed depreciation calculations as of September 30, 2025, are organized
8 and presented in the same manner as those as of September 30, 2027, with
9 two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully
10 Projected) are not necessary and, therefore, are not presented in UGI Gas
11 Exhibit C (Historic).

12
13 **IV. THE DEPRECIATION STUDY - OVERVIEW**

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

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

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

12
13 **Q. Is the Company's claim for annual depreciation in the current proceeding**
14 **based on the same methods of depreciation that were used in the**
15 **Company's March 2025 ADR?**

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

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

1 **V. ORIGINAL COST MEASURE OF VALUE**

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

4 A. As of September 30, 2027, the original cost of gas plant in service is
5 \$6,676,559,249 as shown in column 4 of Table 1 on pages II-3 through II-5 of
6 UGI Gas Exhibit C (Fully Projected). This amount includes \$6,381,927,213 of
7 Gas Plant and \$294,632,036 of Other Utility Plant allocated to UGI Gas. Other
8 Utility Plant is primarily comprised of plant assets included in Common Plant
9 and Information Services ("IS"). The assets included in Common Plant and IS
10 are assets that are shared and jointly used between UGI Gas and UGI Electric.
11 The costs related to Common Plant and IS are allocated to UGI Gas at 89.11
12 percent and 84.82 percent, respectively. Also, the full cost of the buildings at
13 the Empire Service Center ("Empire") in Wilkes Barre, PA were included in Gas
14 Division. However, personnel of UGI Electric share portions of the buildings at
15 that location and therefore a portion of the cost related to Empire was deducted
16 from UGI Gas and allocated to UGI Electric for this proceeding.

17
18 **VI. THE ACCRUED DEPRECIATION CLAIM**

19 **Q. Have you determined UGI Gas's accrued depreciation for ratemaking**
20 **purposes as of September 30, 2027?**

21 A. Yes. I have determined the allocated book depreciation reserve as of
22 September 30, 2027, to be \$1,736,045,978.

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

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

7
8 **Q. How did you determine UGI Gas's allocated book depreciation reserve as**
9 **of September 30, 2026?**

10 A. The book depreciation reserve attributable to UGI Gas as of September 30,
11 2026, is set forth in column 5 of Table 1 of UGI Gas Exhibit C (Future). Table 2
12 of UGI Gas Exhibit C (Future) is an annual bring-forward of the book
13 depreciation reserve as of September 30, 2025, using estimated accruals,
14 retirements, salvage, and cost of removal for the twelve months from October
15 2025 through September 2026. The table sets forth, by plant account, the
16 beginning book reserve balance as of September 30, 2025, the estimated
17 reserve activity, and the ending reserve balance as of September 30, 2026. The
18 estimated reserve activity consists of depreciation accruals (column 3),
19 amortization of net salvage (column 4), projected retirements (column 5),
20 projected salvage (column 6), and projected cost of removal (column 7). Table
21 3 of UGI Gas Exhibit C (Future) sets forth the calculation of the estimated
22 depreciation accruals by plant account, which is carried forward to column 3 of
23 Table 2. The book reserve as of September 30, 2025, by plant account, shown

1 in column 2 of Table 2, was obtained from UGI Gas's books and records and
2 are the same amounts set forth in Table 1 of Exhibit C (Historic).

3
4 **Q. Please explain the manner in which you projected the depreciation**
5 **accruals for the twelve months ended September 30, 2026.**

6 A. The depreciation accruals for the twelve months ended September 30, 2026, by
7 plant account, were estimated by applying the annual depreciation accrual rates
8 calculated as of September 30, 2025, to the projected average 2026 plant
9 balance. The average balance for the twelve months ended September 30,
10 2026, is computed in columns 2 through 7 of Table 3 and is based on the
11 projected additions, retirements, and transfers in columns 3 through 5.

12
13 **Q. With reference to Table 2, column 4, please explain what you mean by "the**
14 **amortization of net salvage" and explain the manner in which you**
15 **projected it.**

16 A. The amortization of net salvage is the annual provision for recovering
17 experienced negative net salvage. This process for recognizing net salvage in
18 the cost of service is in accordance with Pennsylvania ratemaking practice. The
19 amortization of net salvage is based on experienced net salvage during the
20 preceding five-year period, October 1, 2020, through September 30, 2025.

1 **Q. Please explain the manner in which you projected the retirements,**
2 **salvage, and removal costs that are shown in columns 5, 6, and 7 of Table**
3 **2.**

4 A. Retirements were projected by plant account by applying the average retirement
5 ratio, expressed as a percent of additions, for the five fiscal years 2021 through
6 2025, to FTY and FPFTY additions for most plant accounts. For certain General
7 Plant accounts subject to amortization accounting, retirements are recorded
8 when a vintage is fully amortized. All units are retired per books when the age
9 of the vintage reaches the amortization period. Therefore, all vintages that
10 reached or exceeded the amortization period were retired during the FTY for
11 certain General Plant accounts subject to amortization accounting. Salvage and
12 removal costs were projected by plant account by applying the average salvage
13 and cost of removal ratios, expressed as a percent of retirement amounts, for
14 the five years 2021 through 2025, to the projected retirement amounts.

15
16 **Q. Was the book reserve as of September 30, 2027, estimated using the same**
17 **methodology?**

18 A. Yes, it was essentially the same methodology with one minor exception. The
19 book depreciation accruals calculated for fiscal year 2027 were based on
20 applying the depreciation rate to average monthly plant balances for purposes
21 of calculating the book reserve as of September 30, 2027.

1 **VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM**

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

5 A. Yes, I have. The annual depreciation expense is \$182,262,215 and consists of
6 \$172,559,378 of annual accruals to recover original cost and \$9,702,837 of net
7 salvage amortization. These amounts are set forth in column 8 of Table 1 in
8 UGI Gas Exhibit C (Fully Projected).

9
10 **Q. How did you determine the annual accruals of \$182,262,215?**

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

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

20
21 **Q. Please describe the manner in which you estimated the service life**
22 **characteristics for each depreciable group in the first phase of the study.**

23 A. The service life study consisted of compiling historical data from records related
24 to UGI Gas's gas plant; analyzing these data to obtain historical trends of

1 survivor characteristics; obtaining supplementary information from engineering
2 management and operating personnel concerning UGI Gas's practices and
3 plans as they relate to plant operations; and interpreting the above data to form
4 judgments of average service life characteristics.

5
6 **Q. What historical data did you analyze for the purpose of estimating the**
7 **service life characteristics of UGI Gas's gas plant?**

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

13
14 **Q. What method did you use to analyze these service life data?**

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

20
21 **Q. Please describe the results of your use of the retirement rate method.**

22 A. Each retirement rate analysis resulted in a life table, which, when plotted,
23 formed an original survivor curve. Each original survivor curve, as plotted from
24 the life table, represents the average survivor pattern experienced by the

1 several vintage groups during the experience band studied. Inasmuch as this
2 survivor pattern does not necessarily describe the life characteristics of the
3 property group, interpretation of the original curves is required in order to use
4 them as valid considerations in service life estimation. Iowa type survivor
5 curves were used in these interpretations. The results of the retirement rate
6 analyses are presented in Part VI of UGI Gas Exhibit C (Future).

7
8 **Q. Please explain briefly what an "Iowa type survivor curve" is and how you**
9 **use it in estimating service life characteristics for each depreciable**
10 **group.**

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

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

23 The estimated survivor curve designations for each depreciable group
24 indicate the average service life, the family within the Iowa system, and the

1 relative height of the mode. For example, the Iowa 35-R2 curve indicates an
2 average service life of thirty-five years; and a Right-skewed, or R, type curve
3 (the mode or highest frequency of retirements occurs after average life for right
4 modal curves). It also provides a relatively low height, 2, for the mode (possible
5 modes for R type curves range from 0.5 to 5).

6
7 **Q. Did you physically observe plant and equipment in the field?**

8 A. Yes. Field trips are conducted periodically in order to be familiar with the
9 operation of the Company and observe representative portions of the plant.
10 Field trips are conducted each time a service life study is performed. Service
11 life study reports are submitted to the Commission every five years, at a
12 minimum. UGI Gas's most recent service life study report was performed in
13 2023 using plant accounting data through September 30, 2022. Facilities
14 visited during field trips generally include representative city gate stations,
15 district regulating stations, service centers, office buildings, training centers,
16 etc. The specific dates and locations visited during recent field trips are listed
17 in Exhibit C (Future) in Part III. A general understanding of the function of the
18 plant and information with respect to the reasons for past retirements and
19 expected causes of retirements are obtained during these field trips. This
20 knowledge and information was incorporated in the interpretation and
21 extrapolation of the statistical analyses.

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

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

14
15 **Q. Please briefly describe the straight line remaining life method of**
16 **depreciation that you used for depreciable property.**

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

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

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

8

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

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

21

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

23 A. General Plant Accounts 391, 393, 394, 395, 397, and 398 include a very large
24 number of units but represent a very small percent of depreciable gas plant.

1 Depreciation accounting is difficult for these assets, inasmuch as periodic
2 inventories are required to properly reflect plant in service. Many utilities have
3 changed to amortization accounting for general plant as a practical and
4 reasonable solution that avoids significant accounting expenditures for such a
5 small percent of plant.

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

11
12 **VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE**

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

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

1 This account includes primarily cathodically-protected, steel mains,
2 although some bare steel mains are still in service. As detailed in UGI Gas
3 Exhibit C (Future), the Iowa 75-R2.5 survivor curve was judged most
4 appropriate for this account and is the survivor curve used for this filing. The
5 75-R2.5 is a reasonably good fit of the company's historical plant accounting
6 data, consistent with engineering outlook and within the typical range of service
7 lives used by other gas companies for steel mains. The original life table for the
8 1951-2022 experience band is set forth on pages VI-22 through VI-27.

9 The calculation of annual depreciation, the second phase, for the original
10 cost of steel mains in service as of September 30, 2025, is presented by vintage
11 in Part VII on pages VII-37 through VII-45 of UGI Gas Exhibit C (Future) for Gas
12 Plant in Service. The detailed depreciation calculations as of September 30,
13 2026, are presented in Part III of Exhibit C (Fully Projected). The tabular
14 presentations of the detailed depreciation calculations in Part VII of Exhibit C
15 (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully
16 Projected). The expectancy and average life derived from the estimated
17 survivor curve for each vintage were used to calculate the accrued depreciation
18 by the average service life procedure for 1981 and prior vintages.

19 The accrued depreciation for vintages subsequent to 1981 was
20 calculated by the equal life group procedure using the Iowa 75-R2.5 survivor
21 curve. In the calculation, the surviving cost in each vintage was further
22 subdivided, through the use of a computer program, into depreciable groups
23 according to the expected service lives as defined by the Iowa 75-R2.5 survivor
24 curve. The accrued depreciation was derived for each equal life group, based

1 on its service life, and the totals shown for the vintages are the summations of
2 the individually derived amounts.

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

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

14
15 **Q. Is the procedure you described for Account 376.1 typical of that followed
16 for most of the plant investment?**

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

19
20 **Q. Please illustrate the procedure followed for the amortization of certain
21 General Plant accounts and the manner in which it is presented in UGI
22 Gas Exhibit C (Future) using an account as an example.**

23 A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the
24 amortization procedure. As the initial step of the amortization procedure, an

1 amortization period of 20 years was selected based on the period during which
2 such equipment renders most of its service, the amortization periods used by
3 other utilities, and the service life estimate previously used for depreciation
4 accounting.

5 The calculation of the annual amortization as of September 30, 2026, is
6 presented by vintage in Part VII on pages VII-148 and VII-149 of UGI Gas
7 Exhibit C (Future). The calculated accrued amortization is based on the ratio
8 of the vintage's age to the amortization period. The book reserve for vintages
9 older than the amortization period was set equal to the original cost. The
10 remaining book reserve was allocated to vintages based on the calculated
11 accrued depreciation. The future book accruals or amortizations (original cost
12 less assigned or allocated book reserve) were divided by the remaining
13 amortization period to derive the annual amortizations by vintage.

14 The total amortization on page VII-149 of UGI Gas Exhibit C (Future) was
15 brought forward to column 8 of Table 1 on page V-5 of UGI Gas Exhibit C
16 (Future). A similar process was performed for UGI Gas Exhibit C (Fully
17 Projected) and UGI Gas Exhibit C (Historic). That is, the calculation of the
18 annual amortization related to the original cost of Tools, Shop and Garage
19 Equipment in service as of September 30, 2027, is presented by vintage on
20 pages III-148 and III-149 of UGI Gas Exhibit C (Fully Projected) and summa-
21 rized in Table 1 on page II-4.

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

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

11
12 **IX. THE NET SALVAGE AMORTIZATION CLAIM**

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

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

1 account for net salvage and is the method used in preparing the Company's
2 ADR submitted each year to the Commission.

3
4 **Q. Earlier in your testimony you indicated that UGI Gas's annual
5 depreciation expense consists, in part, of \$9,702,837 of net salvage
6 amortization. How did you determine that amount?**

7 A. The \$9,702,837 is the result of determining the five-year average of net salvage
8 experienced and estimated during the period of October 1, 2022 through
9 September 30, 2027. Net salvage is defined in the Uniform System of Accounts
10 as gross salvage less cost of removal. For most gas utilities, including UGI
11 Gas, cost of removal exceeds gross salvage resulting in negative net salvage.
12 Negative net salvage is recorded to the depreciation reserve as a debit, which
13 reduces the depreciation reserve. Charges related to the negative net salvage
14 amortization are recorded to the depreciation reserve as a credit in the five
15 years subsequent to the initial recording of the negative net salvage amount.
16 Therefore, the negative net salvage amount will have been fully amortized after
17 five years and the net effect on the depreciation reserve is zero. Detailed data
18 related to the experienced and estimated cost of removal and salvage are
19 presented in Part VIII of UGI Gas Exhibit C (Future) and Part IV of UGI Gas
20 Exhibit C (Fully Projected).

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

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

15

16 **Q. Does this conclude your direct testimony?**

17 A. Yes, it does.

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. 7 – VICKY A. SCHAPPELL
UGI GAS STATEMENT NO. 8 – DYLAN W. D’ASCENDIS
UGI GAS STATEMENT NO. 9 – DARIN T. ESPIGH
UGI GAS STATEMENT NO. 10 – SHERRY A. EPLER
UGI GAS STATEMENT NO. 11 – JOHN D. TAYLOR
UGI GAS STATEMENT NO. 12 – BRIAN J. MEILINGER**

**UGI UTILITIES, INC. – GAS DIVISION
PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 63**

DOCKET NO. R-2025-3059523

Issued: January 28, 2026

Effective: March 29, 2026

UGI GAS STATEMENT NO. 7

VICKY A. SCHAPPELL

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 7

**Direct Testimony of
Vicky A. Schappell**

Topics Addressed: Capital Planning

Dated: January 28, 2026

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

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

5
6 **Q. By whom are you employed and in what capacity?**

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

12
13 **Q. Please describe your educational background and work experience.**

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

15
16 **Q. What are your responsibilities as Senior Manager?**

17 A. As Senior Manager, I supervise a team of Analysts responsible for the preparation of the
18 annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining
19 budget inputs from various departments including Engineering, Operations, Corrosion,
20 Marketing, Information Technology (“IT”), and the Building and Grounds Departments. I
21 collaborate with the Vice President of Operations, the Vice President of Global
22 Engineering, the Director of Engineering Design, the Director Sales, the Director of
23 Pipeline System Planning and Optimization, the Director Financial Planning and Analysis
24 and Senior Engineering Managers to monitor annual capital budget performance and

1 develop strategies to limit variances in capital installations and spending. I also work
2 closely with the President of UGI in developing the overall capital spend strategy. In this
3 role, I have also prepared testimony with supporting exhibits and schedules, and sponsored
4 responses to discovery requests for past base rate cases. Also, I am responsible for
5 preparing UGI Gas's Annual Asset Optimization Plan. Additionally, I had an integral role
6 in developing an expanded capital spending monitoring process necessary for managing
7 the Company's accelerated capital investments programs.

8
9 **Q. Have you previously presented testimony in proceedings before a regulatory agency?**

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

11
12 **Q. What is the purpose of your testimony?**

13 A. My testimony will address the capital planning process used by UGI Gas which supports
14 the plant in service expenditures included in the proposed rates in this proceeding,
15 specifically as related to plant additions for the future test year ending September 30,
16 2026("FTY"), and the fully projected future test year ending September 30, 2027
17 ("FPFTY" or "FY2027").

18
19 **Q. Are you sponsoring any exhibits in this proceeding?**

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

1 **II. CAPITAL PLANNING**

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

4 A. The total budgeted plant additions for UGI Gas for the FPFTY is \$507,994,000.

5
6 **Q. What are the specific project categories included in the capital budget for UGI Gas?**

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

11
12 **Q. What process does UGI Gas use to develop its capital budget?**

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

21
22 **Q. How does Schedule C-2 show plant additions?**

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

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

4
5 **Q. Have you prepared an exhibit that shows UGI Gas’s plant additions broken down by**
6 **budget project categories?**

7 A. Yes, I have. UGI Gas Exhibit VAS-2 reflects the Company’s plant additions broken out
8 by the different project categories for the five-year period from fiscal year 2023 through
9 fiscal year 2027. The exhibit splits the four budget project categories between Distribution
10 Plant and General and Common Plant, consistent with the categories on Schedule C-2. In
11 addition, UGI Gas Exhibit VAS-2 shows a historical comparison of the total budgeted plant
12 placed in service versus actual plant placed in service additions for the three-year period
13 from fiscal year 2023 through fiscal year 2025. I will describe how the Company’s
14 performance history supports the reasonableness of the Company’s FTY and FPFTY plant
15 additions in greater detail later in my testimony.

16
17 **Q. Please comment on the presentations shown in UGI Gas Exhibit VAS-2 and Schedule**
18 **C-2.**

19 A. While the forecasted total plant in service figures match for the FTY and the FPFTY, there
20 is a difference in the presentation of how UGI Gas Exhibit VAS-2 and Schedule C-2
21 present plant additions, and it is important to understand how these budget presentations
22 align. Specifically, UGI Gas Exhibit VAS-2 shows how the Company’s four individual
23 budget categories constitute the Company’s total Plant Additions and how they map into

1 the Distribution and General and Common Plant on Schedule C-2. Exhibit VAS-2 shows
2 that three of the four budget categories fall into both of the plant categories (i.e.,
3 Distribution Plant and General & Common Plant) when describing the budget by FERC
4 accounts. IT projects are the only budget category where projects fall exclusively into one
5 FERC plant account – General and Common Plant – when recorded for accounting
6 purposes.

7
8 **Q. Why is it important to understand the relationship between the Company’s budgeting**
9 **process and the reflection of the budget in Schedule C-2?**

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

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

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

7
8 **Q. Please describe the prioritization process that is used to evaluate R&B projects.**

9 A. Projects are prioritized for inclusion in the budget according to the condition of, and risks
10 associated with, existing assets, including those factors affecting safety and reliability. In
11 determining the condition of an existing asset, the Company considers various criteria
12 including, but not limited to the replacement of cast iron and bare steel pipe, which are
13 more susceptible to failure from corrosion, cracks, and leakage (as compared to other pipe
14 materials). This comprehensive approach is ultimately utilized which targets the highest
15 risk mains first and incorporates considerations related to the efficient deployment of
16 capital and resources. UGI Gas has also committed to replacing identified priority plastic
17 pipe, in addition to cast iron and bare steel pipe as defined in its Third Long Term
18 Infrastructure Improvement Plan (“LTIP”) as discussed below. Risk evaluations for
19 mains are based on numerous factors, including condition, age, coating, type of ground
20 cover, geographical proximity to structures and prior leak and/or break history. UGI Gas
21 reviews these factors annually to identify the highest risk pipe segments and prioritize them

1 for replacement.¹ Specifically, commercial risk evaluation software is used in concert with
2 a team of Subject Matter Experts to evaluate, prioritize, and bundle replacement projects.
3 Furthermore, UGI Gas’s Distribution Integrity Management Program (“DIMP”) and
4 Transmission Integrity Management Program (“TIMP”) provide a detailed listing and
5 weighting of factors considered in the risk-based evaluation, which may cause specific
6 projects to be reprioritized for replacement on a more accelerated basis

7 UGI Gas’s prioritization of projects for its capital budgets is consistent with its
8 DIMP and LTIP, which is described in more detail in the direct testimony of UGI Gas
9 witness, Jill E. Walter (UGI Gas Statement No. 3). LTIP replacement investments are
10 identified and prioritized on a risk basis in accordance with UGI Gas’s DIMP.

11
12 **Q. Has there been any update in UGI Gas’s priorities for its R&B investments?**

13 A. Yes. As of the end of calendar year 2026, the Company will have completed its cast iron
14 retirement, removing 407 miles from service since this program began in 2013. Beginning
15 in calendar year 2027, the Company shift its R&B focus to bare steel retirement, as well as
16 vintage plastic identification and replacement.

17
18 **Q. How does UGI Gas determine which R&B projects are included in the capital budget
19 for a given year?**

20 A. UGI Gas’s LTIP guides the formulation of the overall R&B capital budget. Within the

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.

1 various categories of the LTIP, R&B projects are selected and prioritized according to the
2 risk-based evaluation process that I described above. The total anticipated budgeted plant
3 additions associated with R&B projects in the FPFTY is \$383,642,000 of which
4 \$383,135,000 is included in Distribution plant additions and \$507,000 is included in
5 General and Common Plant Additions.

6
7 **Q. What are new business projects?**

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

11
12 **Q. Please describe how the new business infrastructure projects are selected for
13 inclusion in the capital budget.**

14 A. The new business portion of the capital budget is developed according to forecasts of new
15 business opportunities, projections of customer conversions, and plans for new
16 construction and development projects. The total anticipated budgeted plant additions
17 associated with new business projects in the FPFTY is \$75,690,000; these additions are
18 included in Distribution plant additions.

19
20 **Q. What are IT projects?**

21 A. IT projects enhance the Company's IT systems in a number of ways. These projects
22 involve hardware and software applications which improve the Company's processes and
23 methods across a wide range of operational concerns or needs, such as capital project

1 management, cybersecurity, customer communications, billing as well as other areas.
2 Further, these projects facilitate the Company’s ability to enter, store, retrieve, and send
3 data and information related to such projects. The total anticipated budgeted plant
4 additions associated with IT projects in the FTY is \$43,732,000. Of this amount,
5 \$18,818,000 relates to one specific large IT project, Field Services Management (“FSM”),
6 which has a planned in-service date of July 2026as presented in the Company’s 2025 Gas
7 Base Rate Case.² The total anticipated budgeted plant additions associated with IT projects
8 in the FPFTY is \$12,032,000 and these projects are included in General and Common Plant
9 Additions.

10
11 **Q. Please describe the prioritization process used to evaluate IT projects.**

12 A. IT projects are prioritized for inclusion in the budget based on identified business needs.
13 UGI relies on an IT Prioritization Committee to develop a prioritized budget based on
14 overall business impact, availability of system support, and resource availability.
15 Examples of IT projects include the Pipeline Risk Management – DIMP project that went
16 into service in September 2025. This project focused on standardizing a tool to maintain
17 compliance and mitigate asset risk.

18
19 **Q. What are Other capital projects?**

20 A. Other capital projects include building-related projects, corrosion control projects, capital
21 tool purchases, and fleet purchases. Building-related projects consist of building and land

² See the Direct Testimony of Vicky A. Schappell, UGI Gas Statement No. 5. *See also, Pa. PUC v. UGI Gas*, R-2024-3052716 (Recommended Decision issued on August 8, 2025 recommending approval of the Joint Petition for Approval of All Issues without modification). No party challenged the Company’s FSM and related IT Plan.

1 purchases, building improvements/renovations, and the purchase of furniture. Corrosion
2 control projects include upgrades and replacements of cathodic protection systems for
3 mains. Capital tool projects encompass new tool purchases for field use during capital
4 projects. These tools include tapping and stopping equipment, safety tools, and leak
5 detection equipment. Fleet purchases are needed to maintain a reliable mode of
6 transportation for field employees along with certain specialty equipment required to
7 perform daily functions. These acquisitions include SUVs, pickup trucks, cargo vans,
8 service body trucks, compressor crew trucks, vacuum trucks, aerial lift trucks, dump trucks,
9 backhoes, excavators, forklifts, and equipment trailers for backhoes and excavators. The
10 total anticipated budgeted plant additions associated with Other projects in the FPFTY is
11 \$36,630,000 of which \$5,597,000 is included in Distribution plant additions and
12 \$31,032,000 is included in General and Common Plant Additions (UGI Gas Exhibit VAS-
13 2).

14
15 **Q. Please describe the prioritization process used to evaluate Other capital projects.**

16 A. The prioritization process for Other capital projects is specific to the need being addressed.
17 Building-related projects are prioritized for inclusion in the budget based on safety,
18 security, regulatory, or financial and strategic needs. Regulatory driven projects may
19 originate from compliance requirements or certain audit observations. Physical security
20 audits may prompt the installation of fencing, gates and access controls. Corrosion control
21 projects involving coated steel main replacements are prioritized for inclusion in the budget
22 according to requirements set forth in the Federal Gas Safety Regulations (49 C.F.R. Part

1 192).³ Corrosion control projects also may depend on unrepairable leakages or emerging
2 main issues. Capital tool projects are prioritized for inclusion in the budget according to
3 the useful life of the existing assets. Fleet purchases are prioritized for inclusion in the
4 budget based on age, condition, maintenance costs, and mileage of the existing asset.

5
6 **Q. Please discuss some of the key drivers which support the increase in UGI Gas's**
7 **FPFTY plant additions as compared to the HTY.**

8 A. The planned capital for FY2027 includes cost increases in R&B associated with
9 complexity, location and size of the remaining bare steel replacement projects, as well as
10 general resource cost increases. It also includes priority plastic pipe as Distribution System
11 Improvement Charge-eligible property that will be replaced through the LTIP on an
12 accelerated basis to reduce associated leaks and overall risks on the Company's distribution
13 system, as defined in the Company's Third LTIP at Docket No. P-2024-3050769. The
14 Company's total planned 2027 replacement miles will be 75 to 85 miles. This includes a
15 planned abandonment of a large section of a wrought iron and bare steel line in the northern
16 part of the Company' service territory due to corrosion. This is compared to the
17 approximately 63 miles of cast iron, bare steel and wrought iron main that were removed
18 and replaced in FY2025.

³ 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.

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

3 A. As shown in UGI Gas Exhibit VAS-2, over the past three years, the Company’s total
4 budgeted in service plant additions were \$1,295,956,000, while the total actual in-service
5 plant additions were \$1,280,839,000. Thus, UGI Gas’s plant in service performance as
6 viewed by variance to budget can be shown to be under 1.2%
7 (\$1,295,956,000/\$1,280,839,000) over the three-year period. UGI Gas Exhibit VAS-2 also
8 shows that over the past five years, the Company’s total budgeted in service plant additions
9 were \$2,083,368, while the total actual in-service plant additions were \$2,085,134. Thus,
10 UGI Gas’s plant in service performance as viewed by variance to budget can be shown to
11 be 0.1% (\$2,085,134/\$2,083,368) over the five-year period. This close correlation is
12 indicative of the Company’s ability to perform in developing a plan for plant additions and
13 reliably executing to that plan. Importantly, the Company manages its budgets in total and
14 as any budget changes are made dollars are reallocated between the four main budget
15 categories, described above, such that the total plant additions align as close as possible to
16 the total plant addition actuals.

17
18 **Q. What process does UGI Gas utilize when developing its capital budgets?**

19 A. During the Company’s annual capital budget process, which occurs during the summer/fall,
20 a two-year budget is prepared. The first year of the capital budget is the basis for the FTY.
21 The second year is a preliminary budget and is the basis for the FPFTY. During the budget
22 process, project managers estimate the total project costs and budgeted in-service dates at
23 the project level based on the current data available. These estimated in-service dates are

1 the basis for the budgeted plant additions as further discussed in the testimony of UGI Gas
2 witness Amy M. Keller (UGI Gas Statement No. 5). As the Company transitions from one
3 budget year to the next, and the preliminary budget year becomes the active budget year,
4 the Company makes certain adjustments to its budget for known and measurable changes
5 in the assumptions about operating conditions that supported the preliminary budget. For
6 example, the Company adjusts its project lists on an annual basis based on operational
7 demands, such as the need to reprioritize projects based on emerging service needs or
8 unanticipated equipment condition changes.

9
10 **Q. What metric is utilized by the Company to track plant addition performance?**

11 A. Exhibit VAS-2 compares plant additions placed in service (i.e., actuals) to the budgeted
12 plant additions between 2023 and 2025 in order to track actual plant addition performance.
13 The exhibit provides these figures by the four above-described budget categories. It also
14 separates them by Distribution Plant and General and Common Plant. Taken together, the
15 Distribution and General and Common Plant categories calculate total Plant Additions.
16 Finally, the exhibit calculates the plant in service as a percent of budget metric for each
17 year and over the three-year period by dividing actuals by budgets.

18 Specifically, during this three-year period, the Company's plant additions averaged
19 98.8% of its budget. The percentage of plant additions is calculated by dividing the actual
20 plant additions by the budgeted plant additions (Actual / Forecast). This close correlation
21 between budgeted and actual plant placed in service over a three-year period shows that
22 UGI Gas's budget process is very effective at identifying its required plant additions, and
23 UGI Gas's capital deployment and management activities perform actual work in near

1 identical level to budgeted levels. In total, this comparative metric supports the Company's
2 ability to successfully plan and execute on the claimed level of plant in service in this case.

3

4 **III. CONCLUSION**

5 **Q. Does this conclude your direct testimony?**

6 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
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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 Base Rate Case	Docket No. R-2024-3052716

UGI GAS

EXHIBIT VAS-2

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

Description	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	5 Year Total		3 Year Total	
	2025	2025	2024	2024	2023	2023	2022	2022	2021	2021	Budget	Actual	Budget	Actual
Natural Gas Production														
Replacement and Betterment										(207)	-	(207)	-	-
Subtotal Natural Gas Production	-	-	-	-	-	-	-	-	-	(207)	-	(207)	-	-
Transmission Plant														
Replacement and Betterment		698		(3)		(241)		(53)		305	-	706	-	454
Growth		142						(239)		239	-	142	-	142
Other		112				(71)		90		(10)	-	120	-	40
Subtotal Transmission Plant	-	952	-	(3)	-	(313)	-	(202)	-	534	-	968	-	636
Distribution														
Replacement and Betterment	315,140	290,910	259,662	243,367	317,228	302,171	281,270	293,795	247,853	229,239	1,421,153	1,359,483	892,030	836,449
Growth	67,447	77,260	67,452	68,926	67,961	92,260	69,493	77,289	65,503	84,264	337,855	400,000	202,860	238,446
Other	6,731	3,955	4,750	5,202	6,100	6,896	7,248	5,573	6,350	5,165	31,178	26,791	17,580	16,053
IT											-	-	-	-
Subtotal Distribution	389,317	372,126	331,864	317,496	391,289	401,327	358,011	376,657	319,706	318,668	1,790,187	1,786,273	1,112,469	1,090,948
General and Common Plant														
Replacement and Betterment	377	1,100	554	838	341	255	178	339	220	437	1,671	2,969	1,272	2,193
Growth	-	-	-	-	-	-	-	-	-	1	-	1	-	-
Other	17,132	22,656	33,504	34,384	52,960	48,386	26,375	30,937	58,650	46,404	188,620	182,768	103,595	105,426
IT	12,665	11,289	15,539	23,630	50,414	46,717	13,839	15,091	10,433	15,632	102,890	112,359	78,619	81,635
Subtotal General and Common Plant	30,174	35,044	49,598	58,852	103,715	95,358	40,392	46,368	69,302	62,474	293,181	298,096	183,487	189,255
Total Plant Additions	419,491	408,122	381,462	376,346	495,003	496,372	398,404	422,823	389,008	381,469	2,083,368	2,085,131	1,295,956	1,280,839
	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)
Plant Additions Placed in Service as % of Budget	(2) / (1)	97.3%	(2) / (1)	98.7%	(2) / (1)	100.3%	(2) / (1)	106.1%	(2) / (1)	98.1%	(2) / (1)	100.1%	(2) / (1)	98.8%

Forecasted Performance

Description	FPFTY Budget 2027	FTY Budget 2026
Distribution		
Replacement and Betterment	383,135	311,002
Growth	75,690	74,698
Other	5,997	10,061
Subtotal Distribution	464,423	395,762
General and Common Plant		
Replacement and Betterment	507	524
Growth		
Other	31,032	30,565
IT	12,032	43,732
Subtotal General and Common Plant	43,572	74,820
Total Forecasted Plant Additions	507,994	470,582

UGI GAS STATEMENT NO. 8

DYLAN W. D'ASCENDIS

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 8

**Direct Testimony of
Dylan W. D’Ascendis**

Topics Addressed: Return on Equity

Dated: January 28, 2026

TABLE OF CONTENTS

1

2

3 **I. POSITION AND QUALIFICATIONS 1**

4 **II. PURPOSE OF DIRECT TESTIMONY 2**

5 **III. GENERAL PRINCIPLES 5**

6 *A. Business Risk..... 9*

7 *B. Financial Risk 11*

8 **IV. UGI GAS AND GAS THE UTILITY PROXY GROUP 11**

9 **V. CAPITAL STRUCTURE 14**

10 **VI. COMMON EQUITY COST RATE MODELS 16**

11 *A. Discounted Cash Flow Model..... 18*

12 *B. The Risk Premium Model 21*

13 *C. The Capital Asset Pricing Model 32*

14 *D. Common Equity Cost Rates for Proxy Group of Domestic, Non-Price Regulated*

15 *Companies based on the DCF, RPM, and CAPM 50*

16 **VII. RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENTS 53**

17 **VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE 54**

18 *A. Business Risk Adjustment 54*

19 *B. Flotation Cost Adjustment 61*

20 **IX. CONCLUSION 65**

21

1 **DIRECT TESTIMONY OF DYLAN W. D’ASCENDIS**

2 **I. POSITION AND QUALIFICATIONS**

3 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.**

4 A. My name is Dylan W. D’Ascendis. My business address is 1820 Chapel Ave., W., Suite
5 300, Cherry Hill, N.J. 08003. I am a Partner at ScottMadden, Inc.

6 **Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND AND**
7 **EXPERIENCE?**

8 A. I have offered expert testimony on behalf of investor-owned utilities before over 40 state
9 regulatory commissions in the United States, the Federal Energy Regulatory Commission,
10 the National Energy Regulator in Canada, the Alberta Utility Commission, one American
11 Arbitration Association panel, and the Superior Court of Rhode Island on issues including,
12 but not limited to, common equity cost rate, rate of return, valuation, capital structure, class
13 cost of service, and rate design.

14 On behalf of the American Gas Association (“AGA”), I calculate the AGA Gas
15 Index, which serves as the benchmark against which the performance of the American Gas
16 Index Fund (“AGIF”) is measured on a monthly basis. The AGA Gas Index and AGIF are
17 a market capitalization-weighted index and mutual fund, respectively, comprised of the
18 common stocks of the publicly traded corporate members of the AGA.

19 I am a member of the Society of Utility and Regulatory Financial Analysts
20 (“SURFA”). In 2011, I was awarded the professional designation “Certified Rate of Return
21 Analyst” by SURFA, which is based on education, experience, and the successful
22 completion of a comprehensive written examination.

23 I am also a member of the National Association of Certified Valuation Analysts
24 (“NACVA”) and was awarded the professional designation “Certified Valuation Analyst”

1 by the NACVA in 2015.

2 I am a graduate of the University of Pennsylvania, where I received a Bachelor of
3 Arts degree in Economic History. I have also received a Master of Business Administration
4 with high honors and concentrations in Finance and International Business from Rutgers
5 University.

6 The details of my educational background and expert witness appearances are
7 included in Appendix A.

8 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY**
9 **COMMISSIONS?**

10 A. Yes. The regulatory commissions before whom I have testified are identified in Appendix
11 A.

12 **II. PURPOSE OF DIRECT TESTIMONY**

13 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**
14 **PROCEEDING?**

15 A. The purpose of my Direct Testimony is to present evidence and provide the Pennsylvania
16 Public Utility Commission (“Commission”) with a recommendation regarding UGI
17 Utilities, Inc. – Gas Division’s (“UGI Gas” or the “Company”) return on common equity
18 (“ROE”) for its natural gas distribution operations, and to provide an assessment of the
19 capital structure to be used for ratemaking purposes. My testimony relies upon Company
20 records, public documents, my personal knowledge and education, and my professional
21 experience.

1 **Q. HAVE YOU PREPARED ANY EXHIBITS OR SCHEDULES IN CONNECTION**
2 **WITH YOUR TESTIMONY?**

3 A. Yes. My analyses and conclusions are supported by the data presented in Exhibit B as
4 Schedules DWD-1 through DWD-10, which have been prepared by me or under my direct
5 supervision and control.

6 **Q. WHAT IS YOUR RECOMMENDED COMMON EQUITY COST RATE?**

7 A. I recommend that the Commission authorize UGI Gas the opportunity to earn an ROE of
8 10.75% on its jurisdictional rate base, based on its actual capital structure. The Company’s
9 requested capital structure consists of 45.75% long-term debt, at an embedded debt cost
10 rate of 5.17%, and 54.25% common equity, to which my recommended ROE of 10.75%
11 would apply. The overall rate of return is summarized on page 1 of Schedule DWD-1 and
12 in Table 1 below:

13 **Table 1: Summary of Recommended Weighted Average Cost of Capital**

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	<u>54.25%</u>	10.75%	<u>5.83%</u>
Total	<u>100.00%</u>		<u>8.20%</u>

14
15 **Q. PLEASE SUMMARIZE YOUR RECOMMENDED ROE.**

16 A. My recommended ROE of 10.75% is summarized on page 2 of Schedule DWD-1. I have
17 assessed the market-based common equity cost rates of companies of relatively similar,
18 but not necessarily identical, risk to UGI Gas. Using companies of relatively comparable
19 risk as proxies is consistent with the principles of fair rate of return established in the *Hope*¹

¹ *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (“*Hope*”).

1 and *Bluefield*² decisions. No proxy group can be identical in risk to any single company.
 2 Consequently, there must be an evaluation of relative risk between the Company and the
 3 proxy group to determine if it is appropriate to adjust the proxy group’s indicated rate of
 4 return.

5 My recommendation results from the application of several cost of common equity
 6 models, specifically the Discounted Cash Flow (“DCF”) model, the Risk Premium Model
 7 (“RPM”), and the Capital Asset Pricing Model (“CAPM”), to the market data of a proxy
 8 group of seven (7) natural gas utility companies (“Gas Utility Proxy Group”) whose
 9 selection criteria will be discussed below. In addition, I applied the DCF model, RPM,
 10 and CAPM to a Non-Price Regulated Proxy Group similar in total risk to the Gas Utility
 11 Proxy Group. The results derived from each cost of common equity model are as follows:

12 **Table 2: Summary of Common Equity Cost Rate**

Discounted Cash Flow Model (DCF)	10.53%
Risk Premium Model (RPM)	10.41% - 10.80%
Capital Asset Pricing Model (CAPM)	10.17% - 11.30%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	<u>10.96% - 11.35%</u>
Indicated Range of Common Equity Cost Rates Before Adjustments for Company- Specific Risk	10.17% - 11.35%
Business Risk Adjustment	0.05%
Flotation Cost Adjustment	<u>0.12%</u>
Indicated Range of Common Equity Cost Rates after Adjustment	<u>10.34% - 11.52%</u>
Recommended Cost of Equity	<u>10.75%</u>

² *Bluefield Water Works Improvement Co. v. Public Serv. Comm’n*, 262 U.S. 679 (1923) (“*Bluefield*”).

1 The rate-making process under the Act, i.e., the fixing of ‘just and
2 reasonable’ rates, involves a balancing of the investor and the
3 consumer interests. Thus we stated in the Natural Gas Pipeline Co.
4 case that ‘regulation does not insure that the business shall produce
5 net revenues.’ 315 U.S. at page 590, 62 S.Ct. at page 745. But such
6 considerations aside, the investor interest has a legitimate concern
7 with the financial integrity of the company whose rates are being
8 regulated. From the investor or company point of view it is
9 important that there be enough revenue not only for operating
10 expenses but also for the capital costs of the business. These include
11 service on the debt and dividends on the stock. Cf. Chicago &
12 Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct.
13 400,402. By that standard the return to the equity owner should be
14 commensurate with returns on investments in other enterprises
15 having corresponding risks. That return, moreover, should be
16 sufficient to assure confidence in the financial integrity of the
17 enterprise, so as to maintain its credit and to attract capital.³

18 In summary, the U.S. Supreme Court has found a return that is adequate to attract
19 capital at reasonable terms enables the utility to provide service while maintaining its
20 financial integrity. As discussed above, and in keeping with established regulatory
21 standards, that return should be commensurate with the returns expected elsewhere for
22 investments of equivalent risk. The Commission’s decision in this proceeding, therefore,
23 should provide the Company with the opportunity to earn a return that is: (1) adequate to
24 attract capital at reasonable cost and terms; (2) sufficient to ensure its financial integrity;
25 and (3) commensurate with returns on investments in enterprises having corresponding
26 risks.

27 Lastly, the required return for a regulated public utility is established on a stand-
28 alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities,
29 like other investors, have capital constraints and must look at the attractiveness of the
30 expected risk-adjusted return of each investment alternative in their capital budgeting

³ *Hope*, 320 U.S. 591 (1944), at 603.

1 process. That is, utility holding companies that own many utility operating companies
2 have choices as to where they will invest their capital within the holding company family.
3 Therefore, the opportunity cost concept applies regardless of the source of the funding,
4 public funding or corporate funding.

5 When funding is provided by a parent entity, the return still must be sufficient to
6 provide an incentive to allocate equity capital to the subsidiary or business unit rather than
7 other internal or external investment opportunities. That is, the regulated subsidiary must
8 compete for capital with all the parent company's affiliates, and with other, similarly
9 situated companies. In that regard, investors value corporate entities on a sum-of-the-parts
10 basis and expect each division within the parent company to provide an appropriate risk-
11 adjusted return.

12 It therefore is important that the authorized ROE reflects the risks and prospects of
13 the utility's operations and supports the utility's financial integrity from a stand-alone
14 perspective, as measured by its combined business and financial risks. Consequently, the
15 ROE authorized in this proceeding should be sufficient to support the operational (i.e.,
16 business risk) and financing (i.e., financial risk) of the Company's utility subsidiary on a
17 stand-alone basis.

18 **Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL**
19 **ESTIMATED IN REGULATORY PROCEEDINGS?**

20 A. Regulated utilities primarily use common stock and long-term debt to finance their
21 permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a
22 regulated utility is based on its weighted average cost of capital, in which, as noted earlier,
23 the costs of the individual sources of capital are weighted by their respective book values.

1 The cost of capital is the return investors require to make an investment in a firm.
2 Investors will provide funds to a firm only if the return that they *expect* is equal to, or
3 greater than, the return that they *require* to accept the risk of providing funds to the firm.

4 The cost of capital (i.e., the combination of the costs of debt and equity) is based
5 on the economic principle of “opportunity costs.” Investing in any asset (whether debt or
6 equity securities) represents a forgone opportunity to invest in alternative assets. For any
7 investment to be sensible, its expected return must be at least equal to the return expected
8 on alternative, comparable risk investment opportunities. Because investments with like
9 risks should offer similar returns, the opportunity cost of an investment should equal the
10 return available on an investment of comparable risk.

11 Whereas the cost of debt is contractually defined and can be directly observed as
12 the interest rate or yield on debt securities, the cost of common equity must be estimated
13 based on market data and various financial models. Because the cost of common equity is
14 premised on opportunity costs, the models used to determine it are typically applied to a
15 group of “comparable” or “proxy” companies.

16 In the end, the estimated cost of capital should reflect the return that investors
17 require in light of the subject company’s business and financial risks, and the returns
18 available on comparable investments.

19 **Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS**
20 **GUARANTEED?**

21 A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the ratemaking process
22 should provide the utility a reasonable opportunity to recover its return of, and return on,
23 its reasonably incurred investments, but it does not guarantee that return. While a utility
24 may have control over some factors that affect the ability to earn its authorized return (e.g.,

1 management performance, operating and maintenance expenses, etc.), there are several
2 factors beyond a utility's control that affect its ability to earn its authorized return. Those
3 may include factors such as weather, the economy, and the prevalence and magnitude of
4 regulatory lag.

5 **A. Business Risk**

6 **Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT**
7 **FOR DETERMINING A FAIR RATE OF RETURN.**

8 A. The investor-required return on common equity reflects investors' assessment of the total
9 investment risk of the subject firm. Total investment risk is often discussed in the context
10 of business and financial risk.⁴

11 Business risk reflects the uncertainty associated with owning a company's common
12 stock without the company's use of debt and/or preferred stock financing. One way of
13 considering the distinction between business and financial risk is to view the former as the
14 uncertainty of the expected earned return on common equity, assuming the firm is financed
15 with no debt.

16 Examples of business risks generally faced by utilities include, but are not limited
17 to, the regulatory environment, mandatory environmental compliance requirements,
18 customer mix and concentration of customers, service territory economic growth, market
19 demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of
20 operating leverage, emerging technologies, the vagaries of weather, and the like, all of
21 which have a direct bearing on earnings.

⁴ As will be discussed later in this testimony, another definition of total risk is systematic risk plus unsystematic risk.

1 Although analysts, including ratings agencies, may categorize business risks
2 individually, as a practical matter, such risks are interrelated and not wholly distinct from
3 one another. When determining an appropriate return on common equity, the relevant
4 issue is where investors see the subject company in relation to other similarly situated
5 utility companies (i.e., the Gas Utility Proxy Group). To the extent investors view a
6 company as being exposed to higher risk, the required return will increase, and vice versa.

7 For regulated utilities, business risks are both long-term and near-term in nature.
8 Whereas near-term business risks are reflected in year-to-year variability in earnings and
9 cash flow brought about by economic or regulatory factors, long-term business risks reflect
10 the prospect of an impaired ability of investors to obtain both a fair rate of return on, and
11 return of, their capital. Moreover, because utilities accept the obligation to provide safe,
12 adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn
13 a fair return on their investment), they generally do not have the option to delay, defer, or
14 reject capital investments. Because those investments are capital-intensive, utilities
15 generally do not have the option to avoid raising external funds during periods of capital
16 market distress, if necessary.

17 Because utilities invest in long-lived assets, long-term business risks are of
18 paramount concern to equity investors. That is, the risk of not recovering the return on
19 their investment extends far into the future. The timing and nature of events that may lead
20 to losses, however, also are uncertain and, consequently, those risks and their implications
21 for the required return on equity tend to be difficult to quantify. Regulatory commissions
22 (like investors who commit their capital) must review a variety of quantitative and
23 qualitative data and apply their reasoned judgment to determine how long-term risks weigh
24 in their assessment of the market-required return on common equity.

1 **B. Financial Risk**

2 **Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT**
3 **FOR DETERMINING A FAIR RATE OF RETURN.**

4 A. Financial risk is the additional risk created by the introduction of debt and preferred stock
5 into the capital structure. The higher the proportion of debt and preferred stock in the
6 capital structure, the higher the financial risk to common equity owners (i.e., failure to
7 receive dividends due to default or other covenants). Therefore, consistent with the basic
8 financial principle of risk and return, common equity investors require higher returns as
9 compensation for bearing higher financial risk.

10 **Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED**
11 **BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (I.E., INVESTMENT**
12 **RISK)?**

13 A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar
14 combined business and financial risks (i.e., total risk) faced by bond investors.⁵ Although
15 specific business or financial risks may differ between companies, the same bond/credit
16 rating indicates that the combined risks are roughly similar from a debtholder perspective.
17 The caveat is that these debtholder risk measures do not translate directly to risks for
18 common equity.

19 **IV. UGI GAS AND GAS THE UTILITY PROXY GROUP**

20 **Q. ARE YOU FAMILIAR WITH UGI GAS'S OPERATIONS?**

21 A. Yes. UGI Gas provides natural gas utility service to over 706,000 customers in certificated
22 portions of 46 eastern and central Pennsylvania counties. UGI Utilities, Inc. holds an A3

⁵ Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., a Moody's rating can be A1, A2 and A3.

1 rating from Moody's, and is not rated by S&P. The Company is not publicly traded, as it
2 is an indirectly owned operating subsidiary of UGI Corporation ("UGI Corp."). UGI Corp.
3 is publicly traded on the NYSE under ticker symbol UGI.

4 **Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN**
5 **ESTIMATING THE ROE FOR THE COMPANY?**

6 A. Because the Company is not publicly traded and does not have publicly traded equity
7 securities, it is necessary to develop groups of publicly traded, comparable companies to
8 serve as "proxies" for the Company. In addition to the analytical necessity of doing so,
9 the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk
10 standards, as discussed above. I have selected two proxy groups that, in my view, are
11 fundamentally risk-comparable to the Company: a Gas Utility Proxy Group, and a Non-
12 Price Regulated Proxy Group, which is comparable in total risk to the Gas Utility Proxy
13 Group.⁶

14 Even when proxy groups are carefully selected, it is common for analytical results
15 to vary from company to company. Despite the care taken to ensure comparability,
16 because no two companies are identical, market expectations regarding future risks and
17 prospects will vary within the proxy group. Therefore, it is common for analytical results
18 to reflect a seemingly wide range, even for a group of similarly situated companies. At
19 issue is how to estimate the ROE from within that range. That determination will be best
20 informed by employing a variety of sound analyses that necessarily must consider the sort
21 of quantitative and qualitative information discussed throughout my Direct Testimony.
22 Additionally, a relative risk analysis between the Company and the Gas Utility Proxy

⁶ The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V.

1 Group must be made to determine whether or not explicit Company-specific adjustments
2 need to be made to the Gas Utility Proxy Group’s indicated results.

3 **Q. PLEASE EXPLAIN HOW YOU SELECTED THE COMPANIES IN THE GAS**
4 **UTILITY PROXY GROUP.**

5 A. The companies selected for the Utility Proxy Group met the following criteria:

- 6 (i) They were included in the Natural Gas Utility Group of *Value Line*
7 *Investment Survey’s Standard Edition* as of August 22, 2025 (“*Value*
8 *Line*”);
- 9 (ii) They have 60% or greater of fiscal year 2024 total operating income derived
10 from, and 60% or greater of fiscal year 2024 total assets attributable to,
11 regulated gas distribution operations;
- 12 (iii) At the time of preparation of this testimony, they had not publicly
13 announced that they were involved in any major merger or acquisition
14 activity (i.e., one publicly-traded utility merging with or acquiring another)
15 or any other major development;
- 16 (iv) They have not cut or omitted their common dividends during the five years
17 ended 2024 or through the time of preparation of this testimony;
- 18 (v) They have *Value Line* and Bloomberg Professional Services
19 (“Bloomberg”) adjusted Beta coefficients (“beta”);
- 20 (vi) They have positive *Value Line* five-year dividends per share growth rate
21 projections; and
- 22 (vii) They have *Value Line*, Zacks, or S&P Capital IQ consensus five-year
23 earnings per share growth rate projections.

24 The following seven companies met these criteria:

1

Table 3: Utility Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corp.	CPK
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Southwest Gas Holdings, Inc.	SWX

2

V. CAPITAL STRUCTURE

3 **Q. WHAT IS UGI GAS'S REQUESTED CAPITAL STRUCTURE?**

4 A. UGI Gas's requested ratemaking capital structure consists of 45.75% long-term debt and
5 54.25% common equity.

6 **Q. WHAT ARE THE TYPICAL SOURCES OF CAPITAL COMMONLY**
7 **CONSIDERED IN ESTABLISHING A UTILITY'S CAPITAL STRUCTURE?**

8 A. Common equity and long-term debt are commonly considered in establishing a utility's
9 capital structure, because they are the typical sources of capital financing a utility's rate
10 base.

11 **Q. PLEASE EXPLAIN.**

12 A. Long-lived assets are typically financed with long-lived securities, so that the overall term
13 structure of the utility's long-term liabilities (both debt and equity) closely match the life
14 of the assets being financed. As stated by Brigham and Houston:

15 In practice, firms don't finance each specific asset with a type of
16 capital that has a maturity equal to the asset's life. However,
17 academic studies do show that most firms tend to finance short-term
18 assets from short-term sources and long-term assets from long-term

1 sources.⁷

2 Whereas short-term debt has a maturity of one year or less, long-term debt may
3 have maturities of thirty (30) years or longer. Although there are practical financing
4 constraints, such as the need to “stagger” long-term debt maturities, the general objective
5 is to extend the average life of long-term debt. Still, long-term debt has a finite life, which
6 is likely to be less than the life of the assets included in rate base. Common equity, on the
7 other hand, is outstanding into perpetuity. Thus, common equity more accurately matches
8 the life of the going concern of the utility, which is also assumed to operate in perpetuity.
9 Consequently, it is both typical and important for utilities to have significant proportions
10 of common equity in their capital structures.

11 **Q. HOW DOES THE COMPANY’S REQUESTED COMMON EQUITY RATIO OF**
12 **54.25% COMPARE WITH THE COMMON EQUITY RATIO MAINTAINED BY**
13 **THE GAS UTILITY PROXY GROUP?**

14 A. As shown on page 2 of Schedule DWD-2, common equity ratios range from 39.40% to
15 60.96% for fiscal year 2024 for the Gas Utility Proxy Group. I also considered *Value Line*
16 projected capital structures for the utilities for 2028-2030. That analysis shows a range of
17 projected common equity ratios between 44.00% and 60.00%.⁸

18 In addition to comparing the Company’s requested common equity ratio with
19 common equity ratios currently maintained by the Gas Utility Proxy Group, I also
20 compared the Company’s common equity ratio with the equity ratios maintained by the
21 operating subsidiaries of the Gas Utility Proxy Group. As shown on page 3 of Schedule

⁷ Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, Concise 4th Ed., Thomson South-Western, 2004, at 574.

⁸ See, pages 2 through 8 of Schedule DWD-3.

1 DWD-2, common equity ratios of the operating utility subsidiaries of the companies in the
2 Gas Utility Proxy Group range from 47.86% to 59.93% for fiscal year 2024, for the Gas
3 Utility Proxy Group's operating subsidiaries. The Company's requested common equity
4 ratio of 54.25% is reasonable and consistent with the range of common equity ratios
5 maintained by the operating utility subsidiaries of the Gas Utility Proxy Group.

6 **Q. GIVEN THE RANGE OF EQUITY RATIOS PRESENT WITHIN THE UTILITY**
7 **PROXY GROUP, IS UGI GAS'S REQUESTED EQUITY RATIO OF 54.25%**
8 **APPROPRIATE FOR RATEMAKING PURPOSES?**

9 A. Yes, it is. The Company's requested equity ratio of 54.25% is appropriate for ratemaking
10 purposes in the current proceeding because it is within the range of the common equity
11 ratios currently maintained, and expected to be maintained, by the Gas Utility Proxy Group
12 and its operating subsidiaries.

13 **VI. COMMON EQUITY COST RATE MODELS**

14 **Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE**
15 **MARKET-BASED?**

16 A. Yes. While a public utility operates a regulated business within the states in which it
17 operates, it still must compete for equity in capital markets along with all other companies
18 of comparable risk, which includes non-utilities. The cost of common equity is thus
19 determined based on equity market expectations for the returns of those companies. If an
20 individual investor is choosing to invest their capital among companies of comparable risk,
21 they will choose a company providing a higher return over a company providing a lower
22 return.

1 **Q. ARE YOUR COST OF COMMON EQUITY MODELS MARKET-BASED?**

2 A. Yes. The DCF model uses market prices in developing the model's dividend yield
3 component. The RPM uses bond ratings and expected bond yields that reflect the market's
4 assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic
5 risk component of equity risk premium, are derived from regression analyses of market
6 prices. The CAPM is market-based for many of the same reasons that the RPM is market-
7 based (i.e., the use of expected bond yields and betas). Selection criteria for comparable
8 risk non-price regulated companies are based on regression analyses of market prices and
9 reflect the market's assessment of total risk.

10 **Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE**
11 **COMPANY'S ROE?**

12 A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I
13 applied to the Gas Utility Proxy Group described above. I also applied these same models
14 to the Non-Price Regulated Proxy Group described later in this section.

15 I rely on these models because reasonable investors use a variety of tools and do
16 not rely exclusively on a single source of information or single model. Moreover, the
17 models on which I rely focus on different aspects of return requirements and provide
18 different insights into investors' views of risk and return. The DCF model, for example,
19 estimates the investor-required return assuming a constant expected dividend yield and
20 growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM
21 approaches) provide the ability to reflect investors' views of risk, future market returns,
22 and the relationship between interest rates and the cost of common equity. Just as the use
23 of market data for the Gas Utility Proxy Group adds the reliability necessary to inform
24 expert judgment in arriving at a recommended common equity cost rate, the use of multiple

1 generally accepted common equity cost rate models also adds reliability and accuracy
2 when arriving at a recommended common equity cost rate.

3 The use of multiple models also makes intuitive sense when we consider that
4 market prices are set by the buying and selling behavior of multiple investors, whose
5 circumstances, objectives, and constraints vary over time and across market conditions.
6 We cannot assume a single method is the best measure of the factors motivating those
7 decisions for all investors at all times. Giving undue weight to a single method runs the
8 very real risk of ignoring important information provided by other methods.

9 In other words, no single model is more reliable than all others under all market
10 conditions. Intuition suggests it is more appropriate to use as many methods as we
11 reasonably can and to reflect the many factors motivating investment decisions as best we
12 can. In this instance, intuition, financial theory,⁹ and financial practice reach a common
13 conclusion: we should apply and reasonably consider multiple methods when estimating
14 the ROE.

15 **A. Discounted Cash Flow Model**

16 **Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?**

17 A. The theory underlying the DCF model is that the present value of an expected future stream
18 of net cash flows during the investment holding period can be determined by discounting
19 those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory
20 indicates that an investor buys a stock for an expected total return rate, which is derived

⁹ As Brigham explains: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the ROE]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 7th ed., The Dryden Press, 1994, at 341.

1 from the cash flows received from dividends and market price appreciation.
2 Mathematically, the dividend yield on market price plus a growth rate equals the
3 capitalization rate, i.e., the total common equity return rate expected by investors.

$$4 \quad K_e = (D_0 (1+g))/P + g$$

5 where:

6 K_e = the required Return on Common Equity;

7 D_0 = the annualized Dividend Per Share;

8 P = the current stock price; and

9 g = the growth rate.

10 **Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?**

11 A. I used the single-stage constant growth DCF model in my analyses.

12 **Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE**
13 **CONSTANT GROWTH DCF MODEL.**

14 A. The unadjusted dividend yields are based on the proxy companies' dividends as of October
15 31, 2025, divided by the average closing market price for the 60 trading days ended
16 October 31, 2025.¹⁰

17 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.**

18 A. Because dividends are paid periodically (quarterly), as opposed to continuously (daily), an
19 adjustment must be made to the dividend yield. This is often referred to as the discrete, or
20 the Gordon Periodic, version of the DCF model.

21 DCF theory calls for using the full growth rate, or D_1 , in calculating the model's
22 dividend yield component. Since the companies in the Gas Utility Proxy Group increase

¹⁰ See, Column 1, page 1 of Schedule DWD-3.

1 their quarterly dividends at various times during the year, a reasonable assumption is to
2 reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$.
3 Because the dividend should be representative of the next 12-month period, this adjustment
4 is a conservative approach that does not overstate the dividend yield. Therefore, the actual
5 average dividend yields in Column 1, page 1 of Schedule DWD-3 have been adjusted
6 upward to reflect one-half the average projected growth rate shown in Column 6.

7 **Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO**
8 **THE GAS UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF**
9 **MODEL.**

10 A. Investors are likely to rely on widely available financial information services, such as
11 *Value Line*, Zacks, and S&P Capital IQ. Investors realize that analysts have significant
12 insight into the dynamics of the industries and individual companies they analyze, as well
13 as companies' abilities to effectively manage the effects of changing laws and regulations,
14 and ever-changing economic and market conditions. For these reasons, I used analysts'
15 five-year forecasts of earnings per share growth in my DCF analysis.

16 Over the long run, there can be no growth in dividends per share without growth in
17 earnings per share. Security analysts' earnings expectations have a more significant
18 influence on market prices than dividend expectations. Thus, using projected earnings
19 growth rates in a DCF analysis provides a better match between investors' market price
20 appreciation expectations and the growth rate component of the DCF.

21 **Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.**

22 A. The results of applying the DCF model to the Gas Utility Proxy Group are shown on page
23 1 of Schedule DWD-3 and in Table 4, below:

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Table 4: DCF Model Results for the Utility Proxy Group

Mean	10.35%
Median	10.71%
Average of Mean and Median	10.53%

In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Gas Utility Proxy Group, I relied on an average of the mean and the median results of the DCF, specifically 10.53% applicable to the Gas Utility Proxy Group. This approach takes into consideration all proxy company results while mitigating high and low side outliers of those results.

B. The Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company’s assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors’ required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively), and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation’s assets and earnings upon liquidation.

1 **Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.**

2 A. The total market approach RPM adds a prospective public utility bond yield to an average
3 of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk
4 premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity
5 risk premium based on authorized ROEs for natural gas distribution utilities.

6 **Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 5.49%**
7 **APPLICABLE TO THE UTILITY PROXY GROUP.**

8 A. The first step in the total market approach RPM analysis is to determine the expected bond
9 yield. Because both ratemaking and the cost of capital, including the common equity cost
10 rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is
11 essential. I relied on a consensus forecast of about 50 economists of the expected yield on
12 Aaa-rated corporate bonds for the six calendar quarters ending with the first calendar
13 quarter of 2027, and *Blue Chip Financial Forecast's* ("Blue Chip") long-term projections
14 for 2027 to 2031, and 2032 to 2036. As shown on line 1, page 1 of Schedule DWD-4, the
15 average expected yield on Moody's Aaa-rated corporate bonds is 5.10%. In order to adjust
16 the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond
17 yield, I made an upward adjustment of 0.39%, which represents a recent spread between
18 Aaa-rated corporate bonds and A2-rated public utility bonds.¹¹ Adding that recent 0.39%
19 spread to the expected Aaa-rated corporate bond yield of 5.10% results in an expected A2-
20 rated public utility bond yield of 5.49%. Since the Gas Utility Proxy Group's average
21 Moody's long-term issuer rating is A3, another adjustment to the expected A2-rated public
22 utility bond is needed to reflect the difference in bond ratings. An upward adjustment of

¹¹ As shown on line 2 and explained in note 2, page 1 of Schedule DWD-4.

0.07%, which represents one-third of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the prospective bond yield applicable to an A3-rated public utility bond.¹² Adding the 0.07% to the 5.49% prospective A2-rated public utility bond yield results in a 5.56% expected bond yield applicable to the Gas Utility Proxy Group.

Table 5: Summary of the Calculation of the Gas Utility Proxy Group Projected Bond Yield¹³

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (<i>Blue Chip</i>)	5.10%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.39%
Adjustment to Reflect the Gas Utility Proxy Group's Average Moody's Bond Rating of A3	0.07%
Prospective Bond Yield Applicable to the Gas Utility Proxy Group	5.56%

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Gas Utility Proxy Group is shown on lines 1 through 8, on page 6 of Schedule DWD-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk premium, and combined *Value Line*, Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these is described below.

¹² As shown on line 4 and explained in note 3, page 1 of Schedule DWD-4.

¹³ As shown on page 1 of Schedule DWD-4.

1 **Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON**
2 **LONG-TERM HISTORICAL DATA?**

3 A. To derive a historical market equity risk premium, I used the most recent holding period
4 returns for the large company common stocks less the average historical yield on Moody's
5 Aaa/Aa-rated corporate bonds for the period 1928 to 2024. The use of holding period
6 returns over a very long period of time is appropriate because it is consistent with the long-
7 term investment horizon presumed by investing in a going concern, i.e., a company
8 expected to operate in perpetuity.

9 The long-term arithmetic mean monthly total return rate on large company
10 common stocks was 12.05% and the long-term arithmetic mean monthly yield on Moody's
11 Aaa/Aa-rated corporate bonds was 5.95% from 1928 to 2024. As shown on line 1 of page
12 6 of Schedule DWD-4, subtracting the mean monthly bond yield from the total return on
13 large company stocks results in a long-term historical equity risk premium of 6.10%.

14 I used the arithmetic mean monthly total return rates for the large company stocks
15 and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they
16 are appropriate for the purpose of estimating the cost of capital as noted in Kroll's Stocks,
17 Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI - 2023").¹⁴ The use of the
18 arithmetic mean return rates and yields is appropriate because historical total returns and
19 equity risk premiums provide insight into the variance and standard deviation of returns
20 needed by investors in estimating future risk when making a current investment. If
21 investors relied on the geometric mean of historical equity risk premiums, they would have
22 no insight into the potential variance of future returns because the geometric mean relates

¹⁴ SBBI-2023, at 193.

1 the change over many periods to a constant rate of change, thereby obviating the year-to-
2 year fluctuations, or variance, which is critical to risk analysis.

3 **Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED**
4 **MARKET EQUITY RISK PREMIUM.**

5 A. To derive the regression-based market equity risk premium of 7.13% shown on line 2, page
6 6 of Schedule DWD-4, I used the same monthly annualized total returns on large company
7 common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated
8 corporate bonds as mentioned above. I modeled the relationship between interest rates and
9 the market equity risk premium using the observed monthly market equity risk premium
10 as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate
11 bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS")
12 regression, in which the market equity risk premium is expressed as a function of the
13 Moody's Aaa/Aa-rated corporate bond yield:

14
$$RP = \alpha + \beta (R_{Aaa/Aa})$$

15 where:

16 RP = the market equity risk premium;

17 α = the regression intercept coefficient;

18 β = the regression slope coefficient; and

19 $R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

1 **Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK**
2 **PREMIUM.**

3 A. The PRPM, published in the *Journal of Regulatory Economics*,¹⁵ was developed from the
4 work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 “for methods
5 of analyzing economic time series with time-varying volatility” or ARCH.¹⁶ Engle found
6 that volatility changes over time and is related from one period to the next, especially in
7 financial markets. Engle discovered that volatility of prices and returns clusters over time
8 and is, therefore, highly predictable and can be used to predict future levels of risk and risk
9 premiums.

10 The PRPM estimates the risk-return relationship directly, as the predicted equity
11 risk premium is generated by predicting volatility or risk. The PRPM is not based on an
12 estimate of investor behavior, but rather on an evaluation of the results of that behavior
13 (i.e., the variance of historical equity risk premiums).

14 The inputs to the model are the historical returns on large company stocks minus
15 the historical monthly yield on Moody’s Aaa/Aa-rated corporate bonds from January 1928
16 through October 2025. Using a generalized form of ARCH, known as GARCH, I
17 calculated the projected equity risk premium using Eviews© statistical software. When
18 the GARCH model is applied to the historical return data, it produces a predicted GARCH
19 variance series and a GARCH coefficient. Multiplying the predicted monthly variance by
20 the GARCH coefficient and then annualizing it produces the predicted annual equity risk
21 premium. The resulting PRPM predicted a market equity risk premium of 7.48%.¹⁷

¹⁵ Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, “A New Approach for Estimating the Equity Risk Premium for Public Utilities”, *The Journal of Regulatory Economics* (December 2011), 40:261-278.

¹⁶ Autoregressive conditional heteroscedasticity; see also www.nobelprize.org.

¹⁷ Shown on line 3, page 6 of Schedule DWD-4.

1 **Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK**
2 **PREMIUM BASED ON VALUE LINE SUMMARY & INDEX DATA FOR YOUR**
3 **RPM ANALYSIS.**

4 A. As noted above, because both ratemaking and the cost of capital are prospective, a
5 prospective market equity risk premium is needed. The derivation of the forecasted or
6 prospective market equity risk premium can be found in note 4, page 6 of Schedule DWD-
7 4. Consistent with my calculation of the dividend yield component in my DCF analysis,
8 this prospective market equity risk premium is derived from an average of the three- to
9 five-year median market price appreciation potential by *Value Line* for the 13 weeks ended
10 October 31, 2025, plus an average of the median estimated dividend yield for the common
11 stocks of the 1,700 firms covered in *Value Line* (Standard Edition).¹⁸

12 The average median expected price appreciation is 40%, which translates to an
13 8.78% annual appreciation, and when added to the average of *Value Line's* median
14 expected dividend yields of 2.13%, equates to a forecasted annual total return rate on the
15 market of 10.91%. The forecasted Moody's Aaa-rated corporate bond yield of 5.10% is
16 deducted from the total market return of 10.91%, resulting in an equity risk premium of
17 5.81%, as shown on line 4, page 6 of Schedule DWD-4.

18 **Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM**
19 **BASED ON THE S&P 500 COMPANIES.**

20 A. Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected
21 total return on the S&P 500 companies using expected dividend yields and long-term
22 growth estimates as a proxy for capital appreciation. The expected total return for the S&P

¹⁸ As explained in detail in note 4, page 6 of Schedule DWD-4.

1 500 is 17.67%. Subtracting the prospective yield on Moody’s Aaa-rated corporate bonds
 2 of 5.10% results in a 12.57% projected equity risk premium as shown on page 6, line 5 of
 3 Schedule DWD-4.

4 **Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK**
 5 **PREMIUM FOR USE IN YOUR RPM ANALYSIS?**

6 A. I gave equal weight to all five equity risk premiums based on each source – historical,
 7 *Value Line* Summary & Index, and aggregate *Value Line*, Bloomberg, and S&P Capital IQ
 8 Market DCF in arriving at a 7.82% equity risk premium.

9 **Table 6: Summary of the Calculation of the Equity Risk Premium Using Total**
 10 **Market Returns¹⁹**

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2024)	6.10%
Regression Analysis on Historical Data	7.13%
PRPM Analysis on Historical Data	7.48%
Prospective Equity Risk Premium using Total Market Returns from <i>Value Line Summary & Index</i> less Projected Aaa Corporate Bond Yields	5.81%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	<u>12.57%</u>
Average	<u>7.82%</u>

11 After calculating the average market equity risk premium of 7.82%, I adjusted it
 12 by beta to account for the risk of the Gas Utility Proxy Group. As discussed below, beta
 13 is a meaningful measure of prospective relative risk to the market as a whole, and is a
 14 logical way to allocate a company’s, or proxy group’s, share of the market’s total equity
 15 risk premium relative to corporate bond yields.

¹⁹ As shown on page 6 of Schedule DWD-4.

1 **Q. WHAT MEASURES OF BETA DO YOU USE IN DETERMINING YOUR BETA-**
2 **ADJUSTED EQUITY RISK PREMIUM?**

3 A. I use two measures of beta to calculate my beta-adjusted equity risk premium: (1) the
4 average of *Value Line* and Bloomberg betas; and (2) *Value Line* betas. As will be discussed
5 in detail below, Bloomberg betas may not accurately reflect the risks of the Gas Utility
6 Proxy Group at this time and should be viewed with caution.

7 **Q. WHAT ARE THE BETA VALUES YOU WILL APPLY TO THE MARKET**
8 **EQUITY RISK PREMIUM?**

9 A. As shown on pages 1 and 2 of Schedule DWD-6, the Gas Utility Proxy Group's average
10 blended beta is 0.61, and its average *Value Line* beta is 0.76. Applying these betas to the
11 market equity risk premium of 7.82% results in equity risk premiums of 4.77% and 5.94%,
12 respectively.

13 **Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P**
14 **UTILITY INDEX AND MOODY'S A2-RATED PUBLIC UTILITY BONDS?**

15 A. I estimated three equity risk premiums based on S&P Utility Index holding period returns,
16 and one equity risk premium based on the expected returns of the S&P Utilities Index,
17 using *Value Line*, Bloomberg, and S&P Capital IQ data. Turning first to the S&P Utility
18 Index holding period returns, I derived a long-term monthly arithmetic mean equity risk
19 premium between the S&P Utility Index total returns of 10.59% and monthly Moody's
20 A2-rated public utility bond yields of 6.42% from 1928 to 2024, to arrive at an equity risk
21 premium of 4.16%.²⁰ I then used the same historical data to derive an equity risk premium
22 of 5.00% based on a regression of the monthly equity risk premiums. The final S&P Utility

²⁰ As shown on line 1, page 9 of Schedule DWD-5.

1 Index holding period equity risk premium involved applying the PRPM using the historical
 2 monthly equity risk premiums from January 1928 to October 2025 to arrive at a PRPM-
 3 derived equity risk premium of 4.22% for the S&P Utility Index.

4 I then derived expected total returns on the S&P Utilities Index of 11.89% using
 5 data from *Value Line*, Bloomberg, and S&P Capital IQ respectively, and subtracted the
 6 prospective Moody’s A2-rated public utility bond yield of 5.49%.²¹ This resulted in equity
 7 risk premium of 6.40%. As with the market equity risk premiums, I averaged the four risk
 8 premiums to arrive at my utility-specific equity risk premium of 4.95%.

9 **Table 7: Summary of the Calculation of the Equity Risk Premium Using**
 10 **S&P Utility Index Holding Returns²²**

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2024)	4.16%
Regression Analysis on Historical Data	5.00%
PRPM Analysis on Historical Data	4.22%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.40%
Average	<u>4.95%</u>

11 **Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 4.84% BASED ON**
 12 **AUTHORIZED ROES FOR NATURAL GAS DISTRIBUTION UTILITIES?**

13 A. The equity risk premium of 4.84% shown on page 10 of Schedule DWD-4 is the result of
 14 a regression analysis based on regulatory awarded ROEs related to the yields on Moody’s
 15 A2-rated public utility bonds and contains the graphical results of a regression analysis of
 16 852 rate cases for natural gas distribution utilities which were fully litigated during the
 17 period from January 1, 1980 through October 31, 2025. It shows the implicit equity risk

²¹ Derived on line 4, page 1 of Schedule DWD-4.

²² As shown on page 9 of Schedule DWD-4.

1 premium relative to the yields on A2-rated public utility bonds immediately prior to the
2 issuance of each regulatory decision. It is readily discernible that there is an inverse
3 relationship between the yield on A2-rated public utility bonds and equity risk premiums.
4 In other words, as interest rates decline, the equity risk premium rises and vice versa, a
5 result consistent with financial literature on the subject.²³ I used the regression results to
6 estimate the equity risk premium applicable to the projected yield on Moody's A2-rated
7 public utility bonds. Given the expected A2-rated utility bond yield of 5.49%, it can be
8 calculated that the indicated equity risk premium applicable to that bond yield is 4.84%.

9 **Q. WHAT IS YOUR CONCLUSION OF THE RANGE OF EQUITY RISK**
10 **PREMIUMS FOR USE IN YOUR TOTAL MARKET APPROACH RPM FOR THE**
11 **GAS UTILITY PROXY GROUP?**

12 A. The range of equity risk premiums I applied to the Gas Utility Proxy Group is from 4.85%
13 to 5.24%, which is the average of the beta-adjusted equity risk premium for the Gas Utility
14 Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk
15 premium.

²³ See, e.g., Robert S. Harris and Felicia C. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", *Journal of Applied Finance*, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity", *Financial Management*, Spring 1985, at 33-45.

Table 8: Summary of Conclusions for the Equity Risk Premium for the Gas Utility Proxy Group²⁴

Beta-Adjusted Equity Risk Premium	4.77% - 5.94%
S&P Utilities Index Equity Risk Premium	4.95%
Authorized ROE Equity Risk Premium	4.84%
Average	4.85% - 5.24%

Q. WHAT IS THE INDICATED RANGE OF RPM COMMON EQUITY COST RATES BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 1 of Schedule DWD-4, and shown on Table 9, below, I calculated a range of indicated common equity cost rates from 10.41% to 10.80% for the Gas Utility Proxy Group based on the total market approach RPM.

Table 9: Summary of the Total Market Return Risk Premium Model²⁵

Prospective Moody's Utility Bond Yield Applicable to the Gas Utility Proxy Group	5.56%
Prospective Equity Risk Premium	4.85% - 5.24%
Indicated Cost of Common Equity	10.41% - 10.80%

C. The Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require

²⁴ As shown on page 5 of Schedule DWD-4.

²⁵ As shown on page 1 of Schedule DWD-4.

1 compensation for systematic risk, which is the result of macroeconomic and other events
2 that affect the returns on all assets. The model is applied by adding a risk-free rate of return
3 to a market risk premium, which is adjusted proportionately to reflect the systematic risk
4 of the individual security relative to the total market as measured by the beta. The
5 traditional CAPM model is expressed as:

$$6 \quad R_s = R_f + \beta (R_m - R_f)$$

7 Where: R_s = Return rate on the common stock;

8 R_f = Risk-free rate of return;

9 R_m = Return rate on the market as a whole; and

10 β = Adjusted beta (volatility of the security relative to
11 the market as a whole).

12 Numerous tests of the CAPM have measured the extent to which security returns
13 and beta are related as predicted by the CAPM, confirming its validity. The empirical
14 CAPM (“ECAPM”) reflects the reality that while the results of these tests support the
15 notion that the beta is related to security returns, the empirical Security Market Line
16 (“SML”) described by the CAPM formula is not as steeply sloped as the predicted SML.²⁶
17 The ECAPM reflects this empirical reality.

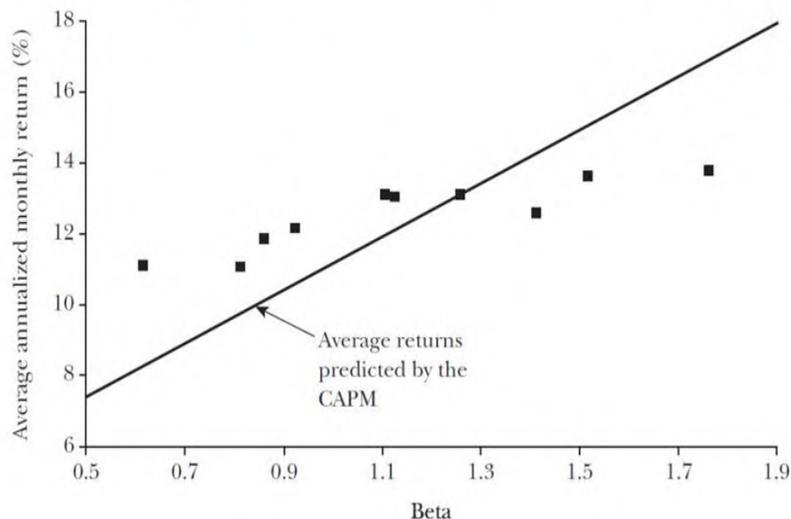
18 **Q. WHY IS THE USE OF THE ECAPM APPROPRIATE IN DETERMINING THE**
19 **ROE FOR THE COMPANY?**

20 A. The ECAPM is a well-established model that has been relied on in both academic and
21 regulatory settings. Fama & French clearly state regarding Figure 2, below, that “[t]he

²⁶ Roger A. Morin, Modern Regulatory Finance (Public Utility Reports, Inc., 2021), at page 223 (“Morin”).

1 returns on the low beta portfolios are too high, and the returns on the high beta portfolios
 2 are too low.”²⁷

Figure 2 <http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430>
 Average Annualized Monthly Return versus Beta for Value Weight Portfolios
 Formed on Prior Beta, 1928–2003



3
 4 In addition, Morin observes that while the results of these tests support the notion
 5 that beta is related to security returns, the empirical SML described by the CAPM formula
 6 is not as steeply sloped as the predicted SML. Morin states:

7 With few exceptions, the empirical studies agree that ... low-beta
 8 securities earn returns somewhat higher than the CAPM would
 9 predict, and high-beta securities earn less than predicted.²⁸

10 * * *

11 Therefore, the empirical evidence suggests that the expected return
 12 on a security is related to its risk by the following approximation:

13
$$K = RF + x (RM - RF) + (1-x) \beta(RM - RF)$$

14 where x is a fraction to be determined empirically. The value of x
 15 that best explains the observed relationship [is] Return = 0.0829 +

²⁷ Eugene F. Fama and Kenneth R. French, “The Capital Asset Pricing Model: Theory and Evidence”, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at 33 (“Fama & French”).

²⁸ Morin, at 207.

1 0.0520 β is between 0.25 and 0.30. If $x = 0.25$, the equation
2 becomes:

3
$$K = RF + 0.25(RM - RF) + 0.75 \beta(RM - RF)^{29}$$

4 Fama & French provide similar support for the ECAPM when they
5 state:

6 The early tests firmly reject the Sharpe-Lintner version of the
7 CAPM. There is a positive relation between beta and average return,
8 but it is too 'flat.'... The regressions consistently find that the
9 intercept is greater than the average risk-free rate... and the
10 coefficient on beta is less than the average excess market return...
11 This is true in the early tests... as well as in more recent cross-
12 section regressions tests, like Fama and French (1992).³⁰

13 Finally, Fama & French further note:

14 Confirming earlier evidence, the relation between beta and average
15 return for the ten portfolios is much flatter than the Sharpe-Linter
16 CAPM predicts. The returns on low beta portfolios are too high,
17 and the returns on the high beta portfolios are too low. For example,
18 the predicted return on the portfolio with the lowest beta is 8.3
19 percent per year; the actual return is 11.1 percent. The predicted
20 return on the portfolio with the t beta is 16.8 percent per year; the
21 actual is 13.7 percent.³¹

22 Clearly, the justification from Morin and Fama & French, along with their reviews
23 of other academic research on the CAPM, validate the use of the ECAPM. In view of
24 theory and practical research, I have applied both the traditional CAPM and the ECAPM
25 to the companies in the Gas Utility Proxy Group and averaged the results.

²⁹ Morin, at 221.

³⁰ Fama & French, at 32.

³¹ Fama & French, at 33.

1 **Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THE VALIDITY OF**
2 **THE ECAPM?**

3 A. Yes, there is. The empirical issues with the CAPM have been present since the
4 presentation of the model, as noted by Dianna R. Harrington in her text Modern Portfolio
5 Theory & the Capital Asset Pricing Model:

6 So far we have learned some very interesting things about the CAPM and
7 reality. Some of the earliest work tested realized data (history) against data
8 generated by simulated portfolios. Early studies by Douglas (1969) and
9 Lintner (Douglas [1969]) showed discrepancies between what was
10 expected on the basis of the CAPM and the actual relationships that were
11 apparent in the capital markets. Theoretically, the minimal rate of return
12 from the portfolios (the intercept) and the actual risk-free rate for the period
13 should have been equal. They were not.

14 * * *

15 Another study, now more famous than Lintner's was done by Black, Jensen,
16 and Scholes (1972). Lintner had used what is called a cross-sectional
17 method (looking at a number of stock returns during one time period),
18 whereas Black, Jensen, and Scholes used a time-series method (using
19 returns for a number of stocks over several time periods). To make their
20 test, Black, Jensen, and Scholes assumed that what had happened in the past
21 was a good proxy for the investor expectations (a frequent assumption in
22 CAPM tests). Using historical data, they generated estimates using what
23 we call the market model:

24
$$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \epsilon_j$$

25 Where:

26 R = total returns

27 β = the slope of the line (the incremental return for risk)

28 α = the intercept or a constant (expected to be 0 over time and across all firms)

29 ϵ = an error term (expected to be random, without information)

30 m = the market proxy

31 j = the firm or portfolio

32 t = the time period

33 Instead of using single stocks, they formed portfolios in an effort to wash
34 out one source of error; because betas of single firms are quite unstable.

35 On the basis of the CAPM, they expected to find

36 1. That the intercept was equal to the risk-free rate (their proxy was
37 the Treasury bill rate)

1 the simple CAPM. If Black’s model is more correct in its description of
2 investor behavior in the marketplace, then the use of the simple model
3 would produce equity return predictions that would be too low for stocks
4 with betas greater than one and too high for stocks with betas of less than
5 one.³³

6 **Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?**

7 A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and
8 Virginia.³⁴

9 **Q. WHAT BETAS DID YOU USE IN YOUR CAPM ANALYSIS?**

10 A. As discussed previously, I use: (1) the average of the *Value Line* and Bloomberg betas,
11 which is consistent with prior testimony, and (2) *Value Line* betas. While both *Value Line*
12 and Bloomberg adjust their calculated (or “raw”) betas to reflect the tendency of beta to
13 regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period,
14 while Bloomberg’s calculation is based on two years of data.

³³ Dianna R. Harrington, *Modern Portfolio Theory & the Capital Asset Pricing Model – A User’s Guide*, Prentice-Hall, Inc. 1983, at 30-31.

³⁴ The Regulatory Commission of Alaska, Docket P-97-7, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues, November 27, 2002, at 146; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi, Final Order, December 3, 2001, at 19; Public Utilities Commission of Nevada, Docket No. 20-02023, Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Order, September 23, 2020, at 35; New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

1 **Q. WHY ARE YOU PRESENTING YOUR MODEL RESULTS EXCLUSIVELY**
2 **USING *VALUE LINE* BETAS ALONGSIDE YOUR TRADITIONAL ANALYSIS?**

3 A. I am presenting my updated model results in this way because recent and historical data
4 show that Bloomberg betas may not accurately reflect the risk of the Gas Utility Proxy
5 Group at this time.

6 **Q. HOW DOES BLOOMBERG CALCULATE BETA?**

7 A. As discussed above, beta is the covariance of a stock relative to a market index divided
8 by the variance of the market return. Bloomberg calculates its beta using two years of
9 weekly return data relative to the S&P 500 Index.

10 **Q. WHAT IS A COVARIANCE?**

11 A. A covariance is comprised of two measures: (1) the relative volatility of the stock, which
12 is the standard deviation of the weekly returns of the stock divided by the standard
13 deviation of the weekly return of the index returns,³⁵ and (2) the correlation of weekly
14 stock and market index returns.³⁶

15 **Q. WHAT HAS THE BLOOMBERG BETA BEEN FOR THE GAS UTILITY PROXY**
16 **GROUP SINCE 2005?**

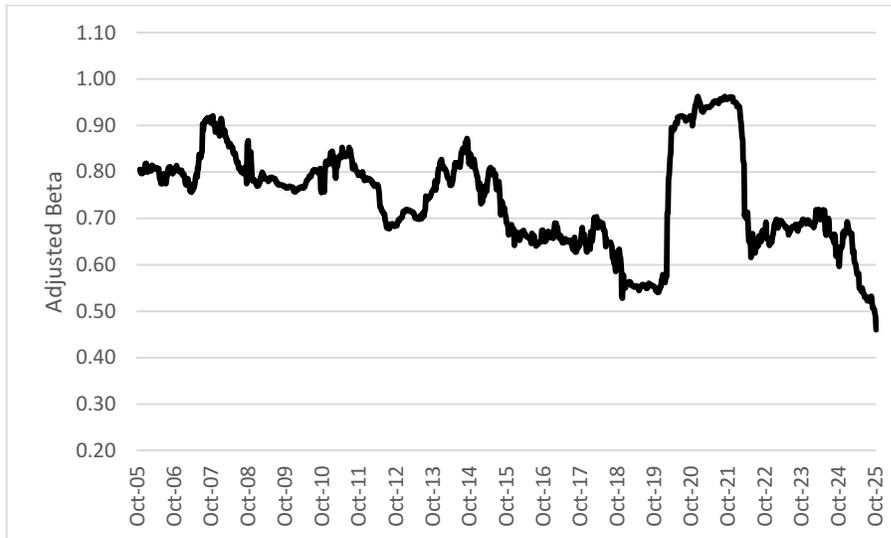
17 A. As shown in Chart 1, below, the Gas Utility Proxy Group average adjusted beta generally
18 has ranged between 0.60 and 0.90, with some high side exceptions (2007-2008 and 2020-
19 2022) and low side exceptions (2018-2020, second half 2024 – present).

20 **Chart 1: Bloomberg Adjusted beta for the Gas Utility Proxy Group 2005-Present³⁷**

³⁵ A relative volatility greater than 1.0 indicates that particular security is more volatile than the market during that calculation period. A relative volatility below 1.0 indicates that the security has less volatility than the market over that calculation period.

³⁶ Correlations range from negative one to positive one. The closer the correlation is to zero the weaker the relationship. Positive values indicate a positive correlation, where the values of both variables tend to increase together

³⁷ Source of Information: Bloomberg Professional Services.



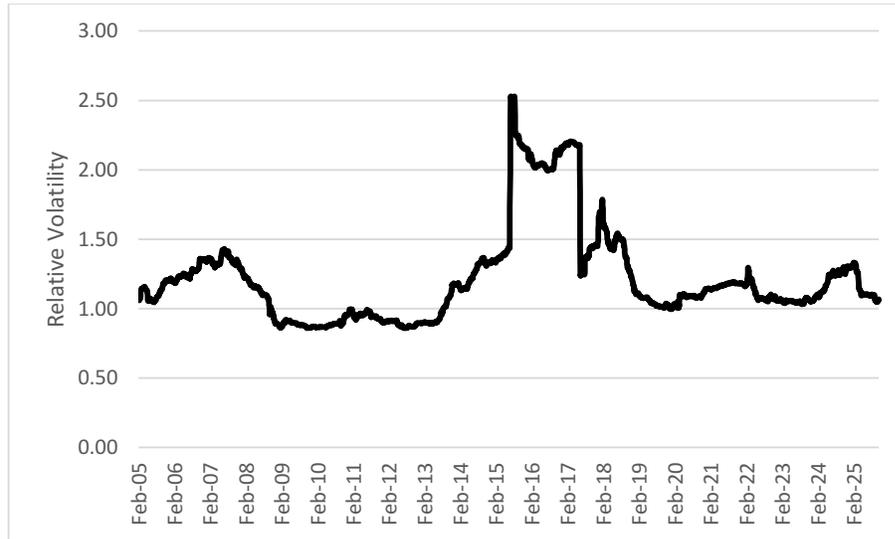
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Q. WHAT HAVE THE COMPONENTS OF BETA (I.E., RELATIVE VOLATILITY AND CORRELATION) SHOWN DURING THAT PERIOD?

A. As shown on Chart 2, the Gas Utility Proxy Group’s relative volatility was generally above 1.0, indicating higher volatility than the S&P 500. On Chart 3, the two-year rolling correlation between the Gas Utility Proxy Group and the S&P 500 has varied over the period 2005 – 2025.

1

Chart 2: Relative Volatility for the Utility Proxy Group 2005-Present³⁸



2

3

4

Chart 3: Correlation of the Utility Proxy Group Relative to the S&P 500 Index 2005-Present³⁹



5

6

7

8

Importantly, as shown on Chart 3, during market distress (i.e., the Great Recession and the COVID-19 pandemic), the correlation of the Gas Utility Proxy Group returns and the S&P 500 returns approached 1.0, showing that utilities, as represented by the Gas

³⁸ Source of Information: S&P Capital IQ.

³⁹ Source of Information: S&P Capital IQ.

1 Utility Proxy Group, do not possess defensive qualities and should not be considered
2 defensive stocks nor are they safe harbor investments in times of market distress.

3 **Q. DOES THE LOWER CORRELATION OF THE GAS UTILITY PROXY GROUP**
4 **RETURNS RELATIVE TO THE S&P 500 RETURNS ALONE NECESSITATE**
5 **THE EXCLUSION OR MITIGATION OF BLOOMBERG BETAS?**

6 A. No. Just as the investor required return varies under different market conditions, so do
7 the model inputs. To determine whether Bloomberg’s default betas calculated relative to
8 the S&P 500 Index are accurately reflecting the risk of the Gas Utility Proxy Group, I
9 compared them with betas calculated using two years of weekly returns relative to the New
10 York Stock Exchange (“NYSE”). The comparison between two-year S&P 500 and NYSE
11 betas are put forth in Chart 4, below:

12 **Chart 4: Comparison of Two-Year S&P 500 and NYSE Betas for the**
13 **Gas Utility Proxy Group 2005-Present⁴⁰**

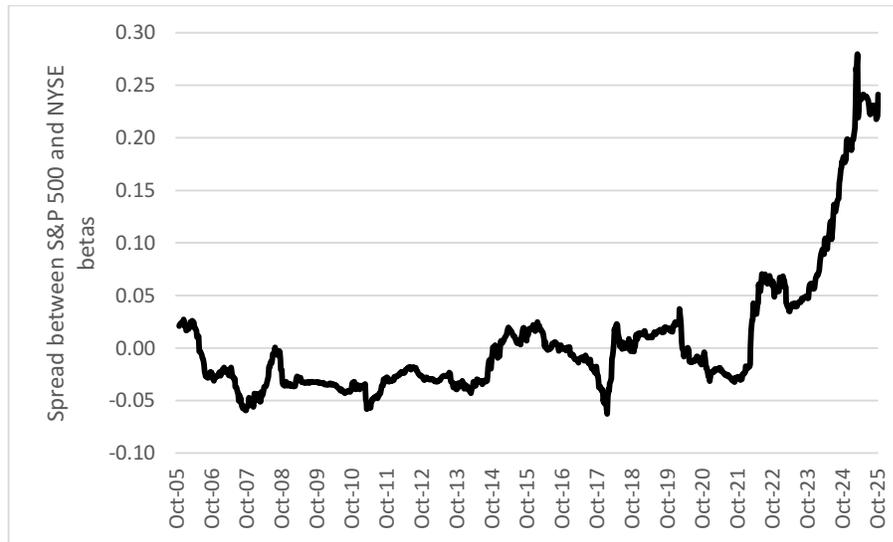


14

⁴⁰ Source of Information: Bloomberg Professional Services.

1 As shown on Chart 4, the two-year S&P 500 and NYSE betas are generally
2 consistent until approximately 2024, when the spread between them expanded beyond
3 historical ranges as shown on Chart 5, below:

4 **Chart 5: Spread Between Two-Year S&P and NYSE Betas for the**
5 **Gas Utility Proxy Group 2005-Present⁴¹**



6
7 In view of Chart 5, it is clear that the relationship between the S&P 500 and NYSE
8 is dislocated. To determine which index was distorting the risk of the Gas Utility Proxy
9 Group, I compared the S&P 500 returns with those of the NYSE and other market indices.

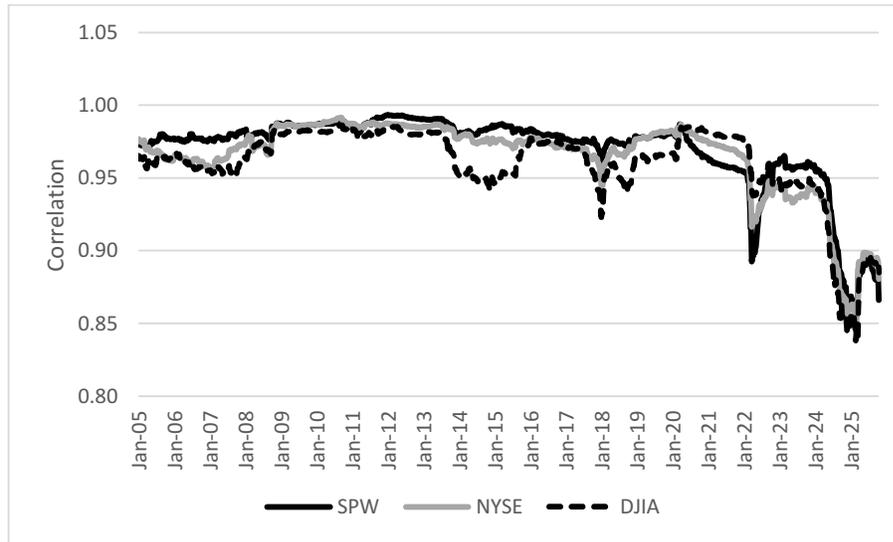
10 **Q. WHICH MARKET INDICES DID YOU USE IN YOUR COMPARISON?**

11 A. In my comparison, I ran correlations between the returns of the S&P 500 and three other
12 market indices: (1) the NYSE; (2) the Dow Jones Industrial Average (“DJIA”); and (3) the
13 S&P 500 Equal Weighted Index (“SPW”). I ran the correlations for the same 2005-2025
14 period in the prior charts, which is put forth in Schedule DWD-5 and Chart 6, below:

⁴¹ Source of Information: Bloomberg Professional Services.

1
2

**Chart 6: Correlation between the S&P 500 Relative to Various Market Indices
2005-Present⁴²**



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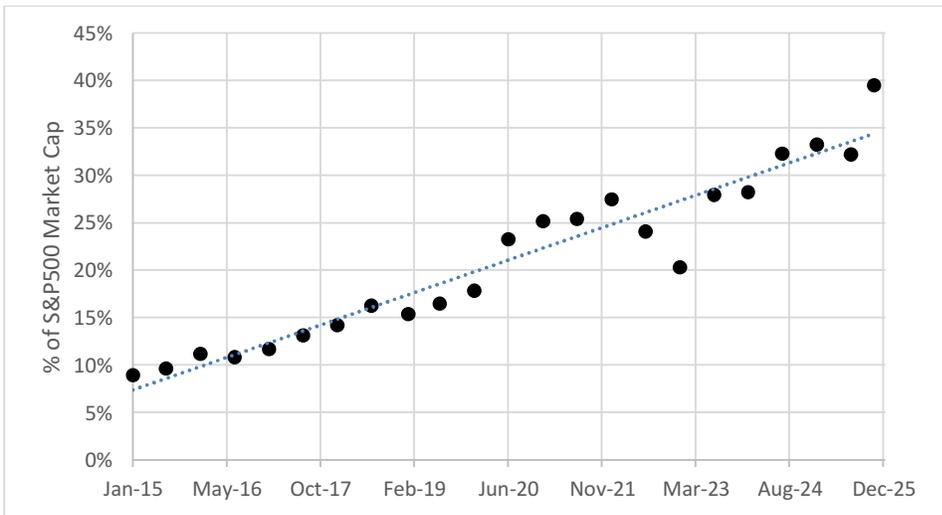
As shown in Chart 6, the two-year rolling correlation between S&P 500's returns and the other market indices' returns generally ranged between 0.95 and 1.00 for the entire period but has recently dipped below 0.85 for each of the measures, indicating that the relationship between the S&P 500 and the other market indices are strained. As shown on pages 2 through 4 of Schedule DWD-5, the two-year rolling correlations of the other market indices are within historical boundaries, whereas, as shown in Chart 6, the correlation in returns between the S&P 500 and the other three indices dropped below 0.90 for an extended period of time. Stated differently, the recent relationship between the S&P 500 Index and the other market indices is inconsistent with their historical relationships while the other market indices have maintained their historical relationships with each other.

⁴² Source of Information: Bloomberg Professional Services.

1 **Q. WHY IS THE RELATIONSHIP BETWEEN THE S&P 500 AND OTHER**
2 **MARKET INDICES DEGRADING?**

3 A. I believe that the concentration of the “Magnificent Seven”⁴³ (“Mag7”) as a percentage of
4 the S&P 500 market capitalization could explain why the two-year rolling correlations
5 between the S&P 500 and the other market indices are degrading. Since 2015, the Mag7
6 stocks’ percentage of the S&P 500 market capitalization has increased from 8.91% to
7 39.46% as shown on Chart 7, below:

8 **Chart 7: Magnificent Seven Stocks Percentage of S&P 500 Market Capitalization**
9 **2015-Present⁴⁴**



10

11 **Q. DOES THE CONCENTRATION AFFECT THE CALCULATION OF BETA FOR**
12 **THE GAS UTILITY PROXY GROUP?**

13 A. Yes, it does. I evaluated the two-year rolling correlation between the Utility Proxy
14 Group’s weekly returns and those returns for the Mag7 and the remaining 493 companies
15 that comprise the S&P 500 index. As shown on Table 10, below, the Gas Utility Proxy

⁴³ The “Magnificent Seven” stocks are: (1) Apple, Inc.; (2) Amazon.com, Inc.; (3) Alphabet, Inc.; (4) Meta Platforms, Inc.; (5) Microsoft Corporation; (6) NVIDIA Corporation; and (7) Tesla, Inc.

⁴⁴ Source of Information: Bloomberg Professional Services.

1 Group's returns had a **negative** 0.1346 correlation with the Mag7 returns and a **positive**
2 0.1810 correlation with the rest of the S&P 500, indicating opposite relationships between
3 the Gas Utility Proxy Group and the two subsets of the S&P 500.

4 **Table 10: Correlation between the Gas Utility Proxy Group's Weekly Returns and**
5 **those of the Magnificent Seven Stocks and the Remaining 493 Component**
6 **Companies of the S&P 500 October 31, 2025⁴⁵**

	Correlation Coefficient 10/31/2025	
	Mag7	Remaining 493
Utility Proxy Group Weekly Returns	-0.1346	0.1810

7 Given the disconnection of the relationship between the Mag7 and the remaining
8 members of the S&P 500 Index relative to the Gas Utility Proxy Group, the concentration
9 of the Mag7 stocks within the S&P 500 Index, and the S&P 500's degrading relationship
10 to other market indices, Bloomberg betas do not accurately reflect the risk of the Gas
11 Utility Proxy Group as compared to the market, and therefore should be viewed with
12 caution.

13 **Q. PLEASE SUMMARIZE YOUR REASONING AS IT PERTAINS TO YOUR USE**
14 **OF BETA IN YOUR ANALYSIS.**

15 A. While the cost of capital and the inputs to cost of capital models vary based on market
16 conditions, these variations should not lead an analyst to eliminate or mitigate a specific
17 input. After investigating historical relationships between betas calculated relative to the
18 S&P 500 and NYSE and the relative volatility and correlation of those betas, I discovered
19 that these relationships are currently not within historical ranges and needed to be
20 investigated further. I then compared returns for the S&P 500 to those of the NYSE, SPW,
21 and DJIA, and discovered that those relationships also have departed from historical
22 benchmarks. Importantly, the NYSE, SPW, and DJIA continue to show high levels of

⁴⁵ Source of Information: S&P Capital IQ.

1 correlation with each other. I then investigated the companies that comprised the S&P 500
2 and found that the Mag7 stocks' return now has an outsized influence on the return on the
3 S&P 500. Looking at the correlations of Gas Utility Proxy Group returns related to Mag7
4 stocks and the remaining 493 stocks that comprise the S&P 500 Index, I discovered
5 opposite relationships (i.e., negative correlation with Mag7 stocks and positive correlations
6 with the remaining 493 stocks). Given the above, I believe that using the S&P 500 Index
7 to calculate betas may not accurately reflect the risk of the Gas Utility Proxy Group and
8 therefore should be viewed with caution. To reflect this in my analysis, I present my
9 analysis using my traditional application of the models as presented in prior testimonies in
10 Pennsylvania and elsewhere, and also present my model results exclusively using *Value*
11 *Line* betas, which are calculated relative to the NYSE.

12 **Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.**

13 A. As shown in Schedule DWD-6, the risk-free rate for both the applications of the CAPM is
14 4.53%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of
15 the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the
16 first calendar quarter of 2027, and long-term projections for the years 2027 to 2031 and
17 2032 to 2036.

18 **Q. WHY DID YOU USE THE PROJECTED 30-YEAR TREASURY YIELD IN YOUR**
19 **ANALYSES?**

20 A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent
21 with the long-term cost of capital to public utilities measured by the yields on Moody's
22 A2-rated public utility bonds; the long-term investment horizon inherent in utilities'
23 common stocks; and the long-term life of the jurisdictional rate base to which the allowed

1 fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury
2 yields are more volatile and largely a function of Federal Reserve monetary policy.

3 **Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM**
4 **FOR THE MARKET USED IN YOUR CAPM ANALYSIS.**

5 A. The basis of the market risk premium is explained in detail in note 1 on page 3 of Schedule
6 DWD-6. As discussed above, the market risk premium is derived from an average of three
7 historical data-based market risk premiums, one *Value Line* data-based market risk
8 premium, and one *Value Line*, Bloomberg, and S&P Capital IQ data-based market risk
9 premium.

10 The long-term income return on U.S. Government securities of 12.29% was
11 deducted from the monthly historical total market return of 4.99%, which results in an
12 historical market equity risk premium of 7.31%.⁴⁶ I applied a linear OLS regression to the
13 monthly annualized historical returns on the S&P 500 relative to historical yields on long-
14 term U.S. Government Securities. That regression analysis yielded a market equity risk
15 premium of 7.96%. The PRPM market equity risk premium is 8.35% and is derived using
16 the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926
17 through October 2025.⁴⁷

18 The *Value Line*-derived forecasted total market equity risk premium is derived by
19 deducting the forecasted risk-free rate of 4.53%, discussed above, from the *Value Line*
20 projected total annual market return of 10.91%, resulting in a forecasted total market equity
21 risk premium of 6.38%.

⁴⁶ *SBBI - 2023*, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21); Bloomberg Professional Services.

⁴⁷ As shown on page 3 of Schedule DWD-6.

1 The S&P 500 projected market equity risk premium using *Value Line*, Bloomberg
 2 and S&P Capital IQ data is derived by subtracting the projected risk-free rate of 4.53%
 3 from the projected total return of the S&P 500 of 17.67%. The resulting market equity
 4 risk premium is 13.14%.

5 These five market risk premium measures, when averaged, result in an average
 6 total market equity risk premium of 8.63%.

7 **Table 11: Summary of the Calculation of the Market Risk Premium**
 8 **for Use in the CAPM⁴⁸**

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2024)	7.31%
Regression Analysis on Historical Data	7.96%
PRPM Analysis on Historical Data	8.35%
Prospective Equity Risk Premium using Total Market Returns from <i>Value Line</i> Summary & Index less Projected 30-Year Treasury Bond Yields	6.38%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from for the S&P 500 less Projected 30-Year Treasury Bond Yields	13.14%
Average	<u>8.63%</u>

9
 10 **Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL**
 11 **AND EMPIRICAL CAPM TO THE GAS UTILITY PROXY GROUP?**

12 A. As shown on page 1 and 2 of Schedule DWD-6, the average of the mean and median
 13 CAPM result using my traditional approach is 10.17%. The average of the mean and
 14 median CAPM using only *Value Line* betas is 11.30%. Given the above, a reasonable
 15 range of CAPM cost rates is from 10.17% to 11.30%.

⁴⁸ As shown on page 3 of Schedule DWD-6.

1 **D. Common Equity Cost Rates for Proxy Group of Domestic, Non-Price Regulated**
2 **Companies based on the DCF, RPM, and CAPM**

3 **Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-**
4 **PRICE REGULATED COMPANIES?**

5 A. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-
6 price regulated firms operating in the competitive marketplace make an excellent proxy if
7 they are comparable in total risk to the Gas Utility Proxy Group being used to estimate the
8 cost of common equity. The selection of such domestic, non-price regulated competitive
9 firms theoretically and empirically results in a proxy group which is comparable in total
10 risk to the Gas Utility Proxy Group, since all of these companies compete for capital in the
11 exact same markets. Moreover, *Hope* and *Bluefield* cases do not specify that comparable
12 risk companies had to be utilities.

13 **Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE**
14 **COMPARABLE IN TOTAL RISK TO THE GAS UTILITY PROXY GROUP?**

15 A. In order to select a proxy group of domestic, non-price regulated companies similar in total
16 risk to the Gas Utility Proxy Group, I relied on betas and related statistics derived from
17 *Value Line* regression analyses of weekly market prices over the most recent 260 weeks
18 (i.e., five years). As shown on Schedule DWD-7, these selection criteria resulted in a
19 proxy group of thirty-two domestic, non-price regulated firms comparable in total risk to
20 the Gas Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and
21 diversifiable company-specific risks. The criteria used in selecting the domestic, non-price
22 regulated firms was:

- 23 (i) They must be covered by *Value Line* (Standard Edition);
24 (ii) They must be domestic, non-price regulated companies, i.e., not utilities;

- 1 (iii) Their unadjusted betas must lie within plus or minus two standard
2 deviations of the average unadjusted beta of the Gas Utility Proxy Group;
3 and
4 (iv) The residual standard errors of the *Value Line* regressions which gave rise
5 to the unadjusted betas must lie within plus or minus two standard
6 deviations of the average residual standard error of the Gas Utility Proxy
7 Group.

8 Betas measure market, or systematic, risk, which is not diversifiable. The residual
9 standard errors of the regressions measure each firm's company-specific, diversifiable risk.
10 Companies that have similar betas and similar residual standard errors resulting from the
11 same regression analyses have similar total investment risk.

12 **Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF**
13 **MODEL, THE RPM, AND THE CAPM FOR THE NON-PRICE REGULATED**
14 **PROXY GROUP?**

15 A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner
16 as described above, I will not repeat the details of the rationale and application of each
17 model. One exception is in the application of the RPM, where I did not use public utility-
18 specific equity risk premiums.

19 Page 2 of Schedule DWD-8 derives the constant growth DCF model common
20 equity cost rate. As shown, the indicated common equity cost rate, using the constant
21 growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Gas
22 Utility Proxy Group, is 11.29%.

23 Pages 3 through 5 of Schedule DWD-8 contain the data and calculations that
24 support the range of indicated RPM common equity cost rates from 10.94% to 11.64%.

1 As shown on line 1, page 3 of Schedule DWD-8, the consensus prospective yield on
2 Moody's Baa2-rated corporate bonds for the six quarters ending in the first quarter of 2027,
3 and for the years 2027 to 2031 and 2032 to 2036, is 5.89%.⁴⁹ Since the Non-Price
4 Regulated Proxy Group has an average Moody's long-term issuer rating of A3, another
5 adjustment to the expected Baa2-rated public utility bond is needed to reflect the difference
6 in bond ratings. A downward adjustment of 0.19%, which represents two-thirds of a recent
7 spread between A2-rated and Baa2-rated corporate bond yields, is necessary to make the
8 prospective bond yield applicable to an A2-rated corporate bond.⁵⁰ Subtracting the 0.19%
9 from the 5.89% prospective Baa2-rated corporate bond yield results in a 5.70% expected
10 bond yield applicable to the Non-Price Regulated Proxy Group.

11 When beta-adjusted risk premiums of 5.24% and 5.94%⁵¹ relative to the Non-Price
12 Regulated Proxy Group are added to the prospective A2-rated corporate bond yield of
13 5.70%, the indicated range of RPM common equity cost rates are from 10.94% to 11.64%.

14 Pages 6 and 7 of Schedule DWD-8 contains the inputs and calculations that support
15 my range of indicated CAPM/ECAPM common equity cost rates from 10.68% to 11.29%.

16 **Q. WHAT IS THE INDICATED RANGE OF COMMON EQUITY COST RATES**
17 **BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE**
18 **IN TOTAL RISK TO THE GAS UTILITY PROXY GROUP?**

19 A. As shown on page 1 of Schedule DWD-8, the results of the common equity models applied
20 to the Non-Price Regulated Proxy Group – which group is comparable in total risk to the
21 Gas Utility Proxy Group – are as follows:

⁴⁹ *Blue Chip Financial Forecasts*, June 2, 2025 at 14 and October 31, 2025 at 2.
⁵⁰ As shown on line 2 and explained in note 2, page 3 of Schedule DWD-8.
⁵¹ Derived on page 5 of Schedule DWD-8.

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2

**Table 12: Summary of Model Results Applied to the
Non-Price Regulated Proxy Group⁵²**

Discounted Cash Flow Model	11.29%
Risk Premium Model	10.94% - 11.64%
Capital Asset Pricing Model	<u>10.68% - 11.29%</u>
Mean	<u>10.97% - 11.41%</u>
Median	<u>10.94% - 11.29%</u>
Average of Mean and Median	<u>10.96% - 11.35%</u>

3 The average of the mean and median of these models indicate a range of cost rates
4 from 10.96% to 11.35%. While I do not consider these results in determining my
5 recommended range of ROEs, I note that they are comparable to my Gas Utility Proxy
6 Group indicated results.

7 **VII. RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENTS**

8 **Q. WHAT IS THE RANGE OF INDICATED COMMON EQUITY COST RATES**
9 **PRODUCED BY YOUR ROE MODELS?**

10 A. The range of indicated ROEs produced from my analysis is from 10.17% to 11.35%. The
11 indicated results of the DCF model, RPM, and CAPM fall within that indicated range. I
12 used multiple cost of common equity models as primary tools in arriving at my
13 recommended common equity cost rate, because no single model is so inherently precise
14 that it can be relied on to the exclusion of other theoretically sound models. Using multiple
15 models adds reliability to the estimated common equity cost rate, with the prudence of
16 using multiple cost of common equity models supported in both the financial literature and
17 regulatory precedent. Based on these common equity cost results, I conclude that a range
18 of common equity cost rates between 10.17% and 11.35% is reasonable.

⁵² As shown on page 1 of Schedule DWD-8.

1 **VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE**

2 **Q. IS IT NECESSARY TO CONDUCT A RELATIVE RISK ANALYSIS BETWEEN**
3 **THE GAS UTILITY PROXY GROUP AND THE COMPANY?**

4 A. Yes. After a proxy group-specific ROE is determined, one must conduct a relative risk
5 analysis to determine whether additional adjustments need to be made to reflect the unique
6 risk of the subject company.

7 **A. Business Risk Adjustment**

8 **Q. DOES UGI GAS'S SMALLER SIZE RELATIVE TO THE GAS UTILITY PROXY**
9 **GROUP COMPANIES INCREASE ITS BUSINESS RISK?**

10 A. Yes. UGI Gas's smaller size relative to the Gas Utility Proxy Group companies indicates
11 greater relative business risk for the Company because, all else being equal, size has a
12 material bearing on risk.

13 Size affects business risk because smaller companies generally are less able to cope
14 with significant events that affect sales, revenues, and earnings. For example, smaller
15 companies face more risk exposure to business cycles and economic conditions, both
16 nationally and locally. Additionally, the loss of revenues from a few larger customers
17 would have a greater effect on a small company than on a bigger company with a larger,
18 more diverse, customer base.

19 As further evidence illustrates that smaller firms are riskier, investors generally
20 demand greater returns from smaller firms to compensate for less marketability and
21 liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module
22 ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of
23 the magnitude of the size premium based on several measures of size. In discussing "Size
24 as a Predictor of Equity Premiums," Kroll states:

1 The size effect is based on the empirical observation that companies of
2 smaller size are associated with greater risk and, therefore, have greater cost
3 of capital [sic]. The “size” of a company is one of the most important risk
4 elements to consider when developing cost of equity capital estimates for
5 use in valuing a business simply because size has been shown to be a
6 *predictor* of equity returns. In other words, there is a significant (negative)
7 relationship between size and historical equity returns - as size *decreases*,
8 returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in
9 original)⁵³

10 Furthermore, in “The Capital Asset Pricing Model: Theory and Evidence,” Fama
11 and French note size is indeed a risk factor which must be reflected when estimating the
12 cost of common equity. On page 38, they note:

13 . . . the higher average returns on small stocks and high book-to-market
14 stocks reflect unidentified state variables that produce undiversifiable risks
15 (covariances) in returns not captured in the market return and are priced
16 separately from market betas.⁵⁴

17 Based on this evidence, Fama and French proposed their three-factor model which
18 includes a size variable in recognition of the effect size has on the cost of common equity.

19 Also, it is a basic financial principle that the use of funds invested, and not the
20 source of funds, is what gives rise to the risk of any investment.⁵⁵ Eugene Brigham, a well-
21 known authority, states:

22 A number of researchers have observed that portfolios of small-firms (sic)
23 have earned consistently higher average returns than those of large-firm
24 stocks; this is called the “small-firm effect.” On the surface, it would seem
25 to be advantageous to the small firms to provide average returns in a stock
26 market that are higher than those of larger firms. In reality, it is bad news
27 for the small firm; **what the small-firm effect means is that the capital**
28 **market demands higher returns on stocks of small firms than on**
29 **otherwise similar stocks of the large firms.** (emphasis added)⁵⁶

⁵³ Kroll: Cost of Capital Navigator: U.S. Cost of Capital Module, “Size as a Predictor of Equity Returns,” at 1.

⁵⁴ Fama & French, at 25-43.

⁵⁵ Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

⁵⁶ Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

1 Consistent with the financial principle of risk and return discussed above, increased
2 relative risk due to small size must be considered in the allowed rate of return on common
3 equity. Therefore, the Commission's authorization of a cost rate of common equity in this
4 proceeding must appropriately reflect the unique risks of UGI Gas's natural gas
5 distribution operations, including its small size, which is justified and supported above by
6 evidence in the financial literature.

7 **Q. INTERVENING WITNESSES OFTEN CITE A STUDY BY DR. ANNIE WONG**
8 **FOR THE PROPOSITION THAT THERE IS NO SIZE PREMIUM FOR**
9 **UTILITIES. DOES THIS STUDY ESTABLISH THAT CONTENTION?**

10 A. No, it does not. In the Wong study, Dr. Wong attempted to relate a change in beta to the
11 size effect. Dr. Wong's beta study is incorrect, as beta is a measure of market risk, whereas
12 size is a company-specific, or diversifiable risk. While betas may contain some measure
13 of diversifiable risk, betas have low explanatory power. As shown in Schedule DWD-10,
14 the R-Squared, which measures the variability of returns applicable to beta, is
15 approximately 0.18 for my Gas Utility Proxy Group, which means approximately 82% of
16 the variation of the Gas Utility Proxy Group's returns are unexplained by beta.

17 **Q. IS THERE ALSO A PUBLISHED RESPONSE TO DR. WONG'S ARTICLE?**

18 A. Yes, there is. In response to Professor Wong's article, *The Quarterly Review of Economics*
19 *and Finance* published an article in 2003, authored by Thomas M. Zepp, which commented
20 on the Wong article often cited by intervening witnesses. Relative to Dr. Wong's results,
21 Dr. Zepp concluded in the Abstract on page 1 of his article: "Her weak results, however,
22 do not rule out the possibility of a small firm effect for utilities."⁵⁷ Dr. Zepp also noted on

⁵⁷ Thomas M. Zepp, "Utility Stocks and the Size Effect --- Revisited", *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-582.

1 page 582 that: “Two other studies discussed here support a conclusion that smaller water
2 utility stocks are more risky than larger ones. To the extent that water utilities are
3 representative of all utilities, there is support for smaller utilities being more risky than
4 larger ones.”⁵⁸

5 **Q. HAVE YOU PERFORMED STUDIES LINKING SIZE AND RISK FOR UTILITY**
6 **COMPANIES?**

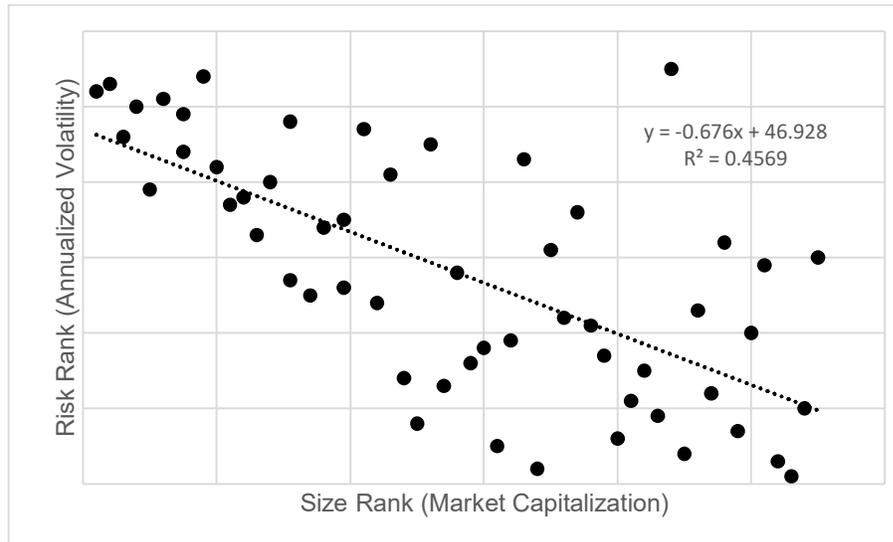
7 A. Yes, I have performed two studies that link size and risk for utility companies. My first
8 study included the universe of electric, gas, and water companies included in *Value Line*
9 Standard Edition. For each of the utilities, the annualized volatility (a measure of risk)⁵⁹
10 was calculated, and each company was ranked by its current market capitalization (a
11 measure of size) as reported by *Value Line*. Ranking the companies by size (smallest to
12 largest) and risk (most risky to least risky), results in the scatterplot shown on Chart 8,
13 below:

⁵⁸ Thomas M. Zepp, “Utility Stocks and the Size Effect --- Revisited”, *The Quarterly Review of Economics and Finance*, 43 (2003), at 578-583.

⁵⁹ Annualized volatility equals the standard deviation of returns over the period multiplied by the square root of 252, or the approximate number of trading days in a year.

1
2

Chart 8: Relationship Between Size and Risk for the *Value Line* Universe of Utility Companies⁶⁰



3

4

As shown in Chart 8 above, as company size decreases (increasing size rank), the annualized volatility increases, linking size and risk for utilities, which is significant at 95.0% confidence level.

5

6

7

The second study used the same universe of companies, but instead of annualized volatility, I used the *Value Line* Safety Ranking, which is another measure of total risk.⁶¹

8

9

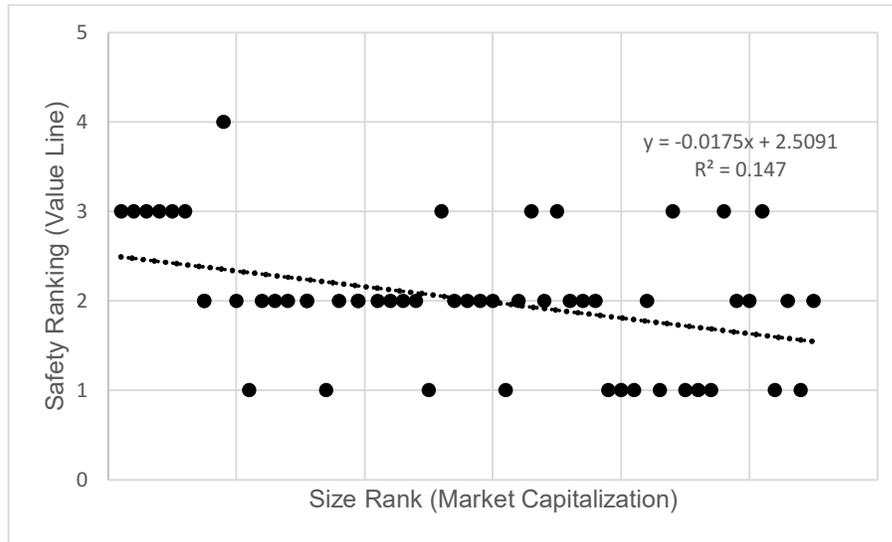
After ranking the companies by size and Safety Ranking, I made a scatterplot of those data, as shown on Chart 9, below:

10

⁶⁰ Source: *Value Line*

⁶¹ *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

1 **Chart 9: Relationship Between Size and Safety Ranking for the *Value Line* Universe of**
 2 **Utility Companies⁶²**



3
 4
 5 Similar to the first study, as company size decreases, Safety Ranking degrades,
 6 indicating a link between size and risk for utilities. This study is also significant at the
 7 95% confidence level. The assertion that size and risk are not linked for utility companies
 8 should be dismissed by the Commission.

9 **Q. IS THERE A WAY TO QUANTIFY A RELATIVE RISK ADJUSTMENT DUE TO**
 10 **UGI GAS’S GREATER BUSINESS RISK RELATIVE TO THE GAS UTILITY**
 11 **PROXY GROUP?**

12 A. Yes. In the absence of other empirical methods, I compared UGI Gas’s and the Gas Utility
 13 Proxy Group’s relative size, as measured by market capitalization on October 31, 2025.

⁶² Source: *Value Line*.

1
2
3

Table 13: Size as Measured by Market Capitalization for the Company and the Gas Utility Proxy Group

	Market Capitalization* (\$ Millions)	Times Greater Than the Company
UGI Gas	\$3,901.539	
Gas Utility Proxy Group Median	\$ 4,801.525	1.2x
*From page 1 of Schedule DWD-9.		

4

The Company's market capitalization was at \$3.90 billion as of October 31, 2025, compared with the median market capitalization of the Utility Proxy Group of \$4.80 billion as of October 31, 2025. The Gas Utility Proxy Group's market capitalization is 1.2 times the size of UGI Gas's market capitalization.

8

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates to reflect UGI Gas's greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2024 period. The average size premium for the Gas Utility Proxy Group with a market capitalization of \$4.80 billion falls in the 5th decile, while UGI Gas's market capitalization of \$4.80 billion places the Company in the 6th decile. The size premium spread between the 5th decile and the 6th decile is 0.26%. Even though a 0.26% upward size adjustment is indicated, I conservatively applied a size premium of 0.05% to UGI Gas's indicated range of common equity cost rates.

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Q. DOES THIS COMMISSION CONSIDER SIZE IN DETERMINING THE AUTHORIZED ROE?

19

20

A. Yes. In Docket No. R-2019-3008212, the Commission stated:

21

Based on the evidence of record, we agree with the recommendation of the ALJs that the Company be awarded a DCF cost of common equity which

22

1 is one standard deviation about the average of the mean and median proxy
2 group ROE from the Company's DCF analysis. In so doing, we recognize
3 that the Company's size is a factor in assessing its ability to attract capital.
4 Accordingly, we shall reject Citizens' Exception No. 10, I&E's Exception
5 No. 4, and the OCA's Exception No. 7, consistent with the following
6 discussion.

7 We are not convinced by the arguments of I&E and the OCA that the ALJs
8 erred in awarding a size adjustment to Citizens'. Rather, we are of the same
9 position as the ALJs that the Company's witness Mr. D'Ascendis offered
10 persuasive record evidence that there is a general inverse relationship
11 between size and risk, such that smaller utilities like Citizens' face greater
12 risk.⁶³

13 **Q. WHAT WOULD BE THE ROE RESULT USING THE COMMISSION'S METHOD**
14 **IN THIS CASE?**

15 A. The average of the mean and median DCF model result is 10.53%, as shown on page 1 of
16 Schedule DWD-3. The standard deviation of those results is 1.51%. Adding the standard
17 deviation to the average of the mean and median DCF result would indicate an ROE of
18 12.04% for UGI Gas, which is higher than my ultimate recommendation in this case. In
19 view of this, my size adjustment should be considered conservative.

20 **B. Flotation Cost Adjustment**

21 **Q. WHAT ARE FLOTATION COSTS?**

22 A. Flotation costs are those costs associated with the sale of new issuances of common stock.
23 They include market pressure and the mandatory unavoidable costs of issuance (e.g.,
24 underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every
25 dollar raised through debt or equity offerings, the Company receives less than one full
26 dollar in financing.

⁶³ Pennsylvania Public Utility Commission, Docket No. R-2019-3008212, Opinion and Order, at 103.

1 **Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE**
2 **ALLOWED COMMON EQUITY COST RATE?**

3 A. It is important because there is no other mechanism in the ratemaking paradigm through
4 which such costs can be recognized and recovered. Because these costs are real,
5 necessary, and legitimate, recovery of these costs should be permitted. As noted by
6 Morin:

7 The costs of issuing these securities are just as real as operating and
8 maintenance expenses or costs incurred to build utility plants, and fair
9 regulatory treatment must permit the recovery of these costs....

10 The simple fact of the matter is that common equity capital is not
11 free...[Flotation costs] must be recovered through a rate of return
12 adjustment.⁶⁴

13 **Q. SHOULD FLOTATION COSTS BE RECOGNIZED ONLY IF THERE WAS AN**
14 **ISSUANCE DURING THE TEST YEAR OR THERE IS AN IMMINENT POST-**
15 **TEST YEAR ISSUANCE OF ADDITIONAL COMMON STOCK?**

16 A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking
17 paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs
18 are charged to capital accounts and are not expensed on a utility's income statement. As
19 such, flotation costs are analogous to capital investments, albeit negative, reflected on the
20 balance sheet. Recovery of capital investments relates to the expected useful lives of the
21 investment. Since common equity has a very long and indefinite life (assumed to be
22 infinity in the standard regulatory DCF model), flotation costs should be recovered through
23 an adjustment to common equity cost rate, even when there has not been an issuance during

⁶⁴ Morin, at 329.

1 the test year, or in the absence of an expected imminent issuance of additional shares of
2 common stock.

3 Historical flotation costs are a permanent loss of investment to the utility and
4 should be taken into account. When any company, including a utility, issues common
5 stock, flotation costs are incurred for legal, accounting, printing fees, and the like. For
6 each dollar of issuing market price, a small percentage is expensed and is permanently
7 unavailable for investment in utility rate base. Since these expenses are charged to capital
8 accounts and not expensed on the income statement, the only way to restore the full value
9 of that dollar of issuing price with an assumed investor required return of 10% is for the
10 net investment, \$0.95, to earn more than 10% to net back to the investor a fair return on
11 that dollar. In other words, if a company issues stock at \$1.00 with 5% in flotation costs,
12 it will net \$0.95 in investment. Assuming the investor in that stock requires a 10% return
13 on their invested \$1.00 (i.e., a return of \$0.10), the company needs to earn approximately
14 10.5% on its invested \$0.95 to receive a \$0.10 return.

15 **Q. DO THE COMMON EQUITY COST RATE MODELS YOU HAVE USED**
16 **ALREADY REFLECT INVESTORS' ANTICIPATION OF FLOTATION COSTS?**

17 A. No. All of these models assume no transaction costs. The literature is quite clear that these
18 costs are not reflected in the market prices paid for common stocks. For example, Brigham
19 and Daves confirm this and provide the methodology utilized to calculate the flotation
20 adjustment.⁶⁵ In addition, Morin confirms the need for such an adjustment even when no
21 new equity issuance is imminent.⁶⁶ Consequently, it is proper to include a flotation cost

⁶⁵ Eugene F. Brigham and Phillip R. Daves, *Intermediate Financial Management*, 9th Edition, Thomson/Southwestern, at p. 342.

⁶⁶ Morin, at 339.

1 adjustment when using cost of common equity models to estimate the common equity cost
2 rate.

3 **Q. WHAT IS THE IMPACT TO INVESTORS IF THE RECOVERY OF FLOTATION**
4 **COSTS IS DENIED?**

5 A. Denying recovery of issuance costs penalizes the investors that fund the utility operations.
6 As shown on page 2 of Schedule DWD-11, because of flotation costs, an authorized return
7 of 10.85% would be required to realize an ROE of 10.75% (i.e., a 10-basis point flotation
8 cost adjustment). If flotation costs are not recovered, the growth rate falls and the ROE
9 decreases to 10.65% (i.e., below the required return).⁶⁷

10 **Q. DO YOU AGREE THAT FLOTATION COSTS CAN BE RECOVERED AS AN**
11 **EXPENSE RATHER THAN AN ADJUSTMENT TO THE ROE?**

12 A. No, I do not. The reason being is due to opportunity cost. When an entity issues equity or
13 debt, the net proceeds of that capital is generally used to finance rate base, which is entitled
14 to a return of (depreciation) and a return on (the weighted average cost of capital). Because
15 the cost of issuing the capital would otherwise go to financing rate base, the costs of that
16 capital would need to be recovered on an ongoing basis.

17 **Q. HAVE OTHER REGULATORY COMMISSIONS ALLOWED FLOTATION**
18 **COSTS IN THE ALLOWED ROE?**

19 A. Yes, they have. For example, in Peoples Gas System, Inc.’s (“PGS”) recent 2023 rate
20 proceeding, the Florida Public Service Commission stated the following regarding my
21 proposed flotation cost adjustment:

22 In PGS’s last rate case in 2008, we did not make a specific adjustment for
23 flotation costs, but in our order we stated that we have traditionally recognized

⁶⁷ Schedule DWD-11, page 2 is provided for illustrative purposes only. Please note that I have not relied on the results of the analysis in determining my recommended ROE or range.

1 a reasonable adjustment for flotation costs in the determination of the investor
2 required return...We find witness D'Ascendis's method to determine the
3 flotation cost is credible and provided persuasive evidence for his
4 recommendation to include a flotation cost of 9 basis points.⁶⁸

5 Given the above, I recommend this Commission also correctly include flotation
6 costs in the allowed ROE.

7 **Q. HOW DID YOU CALCULATE THE FLOTATION COST ALLOWANCE?**

8 A. I modified the DCF calculation to provide a dividend yield that would reimburse investors
9 for issuance costs in accordance with the method cited in literature by Brigham and Daves,
10 as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing
11 equity that were incurred by UGI Corp. Based on the issuance costs shown on page 1 of
12 Schedule DWD-11, an adjustment of 0.12% is required to reflect the flotation costs
13 applicable to the Gas Utility Proxy Group.

14 **Q. WHAT IS THE INDICATED COST OF COMMON EQUITY AFTER YOUR
15 COMPANY-SPECIFIC ADJUSTMENTS?**

16 A. Applying the 0.05% business risk adjustment and the 0.12% flotation cost adjustment to
17 the indicated range of common equity cost rates between 10.17% and 11.35% results in a
18 range of common equity cost rates between 10.34% and 11.52%.⁶⁹

19 **IX. CONCLUSION**

20 **Q. WHAT IS YOUR RECOMMENDED ROE FOR UGI GAS?**

21 A. Given the discussion above and the results of my analytical models, I conclude that an
22 appropriate ROE for the Company is 10.75%.

⁶⁸ *In re: Petition for rate increase by Peoples Gas System, Inc.*, Docket No. 20230023-GU, Order Granting in Part and Denying in Part Peoples Gas System, Inc.'s Petition for a Rate Increase, at 68 (December 27, 2023).

⁶⁹ A credit risk adjustment is not necessary in this proceeding, as UGI Gas's long-term issuer rating is equivalent to the average long-term issuer rating of the Gas Utility Proxy Group.

1 **Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.75% FAIR AND**
2 **REASONABLE TO UGI AND ITS CUSTOMERS?**

3 A. Yes, it is.

4 **Q. IN YOUR OPINION, IS UGI GAS'S PROPOSED CAPITAL STRUCTURE**
5 **CONSISTING OF 45.75% LONG-TERM DEBT AND 54.25% COMMON EQUITY**
6 **FAIR AND REASONABLE?**

7 A. Yes, it is.

8 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

9 A. Yes, it does.

APPENDIX A

for

Dylan W. D'Ascendis

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 17 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Goat Lake Hydro, Inc.	12/24	Goat Lake Hydro, Inc.	Docket No. TA7-521	Rate of Return
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	09/25	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Annual Formula Rate Adjustment Mechanism
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
Union Pacific Railroad Co – dba Keene Water System	03/25	Union Pacific Railroad Co – dba Keene Water System	Docket No. A25-03-016	Rate of Return
Southwest Gas Corporation	07/24	Southwest Gas Corporation	Docket No. A24-09-001	Return on Equity
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
City of Edmonton, Canada				
EPCOR Water Services, Inc.	05/24	EPCOR Water Services, Inc.	Performance Based Regulation Application	Cost of Capital

Sponsor	Date	Case/Applicant	Docket No.	Subject
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/25	Artesian Water Company, Inc.	Docket No. 25-0436	Rate of Return
Delmarva Power & Light Co.	09/24	Delmarva Power & Light Co.	Docket No. 24-1044 (Gas)	Return on Equity
Tidewater Utilities, Inc.	08/24	Tidewater Utilities, Inc.	Docket No. 24-0991	Rate of Return
Delmarva Power & Light Co.	07/24	Delmarva Power & Light Co.	Docket No. 24-0868	Alternative Forms of Rate Regulation
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	08/24	Washington Gas Light Company	Formal Case No. 1180	Rate of Return
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Peoples Gas System, Inc.	03/25	Peoples Gas System, Inc.	Docket No. 20250029-GU	Return on Equity
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Kaupulehu Waste Water Company	02/25	Kaupulehu Waste Water Company	Docket No. 2023-0456	Rate of Return
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/25	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 25-0084 (Gas)	Return on Equity
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/25	Atmos Energy Corporation	26-ATMG-026-RTS	Rate of Return
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
PPL Corporation	05/25	Kentucky Utilities Company / Louisville Gas & Electric Company	2025-00113 / 00114	Rate of Return
Atmos Energy Corporation	09/24	Atmos Energy Corporation	2024-00276	Rate of Return
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unutil	05/23	Northern Utilities, Inc. d/b/a Unutil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unutil Corporation	09/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Unitil Corporation	09/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy Corporation	06/25	Atmos Energy Corporation	Docket No. 2025-UN-59	Rate of Return
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	5/25	Unitil Corporation	Docket No. DE 25-025	Return on Equity
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	06/25	Middlesex Water Company	Docket No. WR25060372	Rate of Return
Atlantic City Electric Company	11/24	Atlantic City Electric Company	Docket No. ER24110854	Rate of Return
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER23020091	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/25	Carolina Water Service, Inc.	Docket No. W-354, SUB 450	Rate of Return
Aqua North Carolina Inc.	04/25	Aqua North Carolina Inc.	Docket No. W-218, Sub 629	Rate of Return
Pluris Hampstead, LLC	09/24	Pluris Hampstead, LLC	Docket No. W-1305, Sub 38	Rate of Return
Old North State Water Co., Inc.	06/24	Old North State Water Co., Inc.	Docket No. W-1300, Sub 100	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Aqua Ohio, Inc.	07/25	Aqua Ohio, Inc.	Case No. 25-0594-WW-AIR	Rate of Return
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Oklahoma Corporation Commission				
Summit Utilities Oklahoma, Inc.	6/25	Summit Utilities Oklahoma, Inc.	Docket No. PUD25-000028	Return on Equity
Pennsylvania Public Utility Commission				
The York Water Company	05/25	The York Water Company	Docket Nos. R-2025-3053442 & R-2025-3053573	Rate of Return
Valley Energy, Inc.	04/25	C&T Enterprises	Docket No. R-2025-3054393	Rate of Return
Wellsboro Electric Company	04/25	C&T Enterprises	Docket No. R-2025-3054392	Rate of Return
Citizens' Electric Company of Lewisburg	04/25	C&T Enterprises	Docket No. R-2025-3054394	Rate of Return
FirstEnergy	04/24	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
CSWR – Limestone Water Utility Operating Company	07/24	CSWR – Limestone Water Utility Operating Company	Docket No. 24-00044	Capital Structure, Cost of Debt, Return on Equity
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Oncor Electric Delivery Co. LLC	06/25	Oncor Electric Delivery Co. LLC	Docket No. 58306	Return on Equity
Aqua Texas, Inc.	06/25	Aqua Texas, Inc.	Docket No. 58124	Rate of Return
CSWR TX Utility Operating Co, LLC	12/24	CSWR TX Utility Operating Co, LLC	Docket No. 57386	Rate of Return
BVRT Utility Holding Co., LLC	07/24	Texas Water Utilities, LP	Docket No. 56664	Rate of Return
Texas Water Utilities, LP	06/24	Texas Water Utilities, LP	Docket No. 56665	Rate of Return
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Texas Division	11/24	Atmos Energy Corporation – Mid-Texas Division	Docket No. OS-24-00019196	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy Corporation – West Texas Division	10/24	Atmos Energy Corporation – West Texas Division	Docket No. OS-24-00018879	Return on Equity
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Washington Gas Light Company	07/25	Washington Gas Light Company	PUR-2025-00091	Return on Equity
Aqua Virginia, Inc.	07/25	Aqua Virginia, Inc.	PUR-2025-00071	Rate of Return
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

UGI GAS STATEMENT NO. 9

DARIN T. ESPIGH

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 9

**Direct Testimony of
Darin T. Espigh**

Topics Addressed: Taxes and Tax Adjustments

Dated: January 28, 2026

1 **Q. Please describe the purpose of your testimony.**

2 A. I am providing testimony on behalf of UGI Gas. I will explain the Company's *pro forma*
3 tax adjustments to its principal accounting exhibits for the fully projected future test year
4 ending September 30, 2027 ("FPFTY"). I will also explain the tax adjustments made to
5 the results of UGI Gas's historic test year ended September 30, 2025 ("HTY") and future
6 test year ending September 30, 2026 ("FTY").

7
8 **Q. Have you testified previously before this Commission?**

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

10

11 **Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?**

12 A. Yes. I am sponsoring the UGI Gas Exhibits: DTE-1 and DTE-2. Together with other
13 Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected),
14 UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related
15 items. These exhibits comprise UGI Gas's principal accounting exhibits for the HTY,
16 FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing
17 requirements and standard data requests as indicated on the master list accompanying this
18 filing.

19

20 **II. TAX ADJUSTMENTS**

21 **Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to the**
22 **proposed tax adjustments.**

23 A. As explained in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No.
24 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which

1 includes a presentation for the FPFTY. Section D of UGI Gas Exhibit A (Fully Projected)
2 presents necessary adjustments to budgeted levels of expense items and revenues. The *pro*
3 *forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These
4 tax adjustments are used to derive UGI Gas’s *pro forma* income at present and proposed
5 rates as set forth in Schedule A-1 of the same exhibit.

6 UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format
7 of UGI Gas Exhibit A (Fully Projected) but reflect data for the HTY and the FTY. This
8 information is provided to comply with the Commission’s filing requirements and provides
9 a basis for comparing UGI Gas’s FPFTY claims with adjusted actual book results from the
10 HTY and adjusted FTY results. UGI Gas Exhibit A (Historic), Schedule D-31, and UGI
11 Gas Exhibit A (Future), Schedule D-31, include adjustments that share the same
12 methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

13
14 **A. TAXES OTHER THAN INCOME TAXES**

15 **Q. How was the provision for taxes-other-than-income taxes (“TOTI”) determined for**
16 **the FPFTY?**

17 A. TOTI consists of the Pennsylvania Utility Realty Tax (“PURTA”), Pennsylvania and Local
18 taxes, Social Security taxes, Federal Unemployment tax (“FUTA”), State Unemployment
19 tax (“SUTA”) and the Company’s assessed contribution to the Commission, Office of
20 Consumer Advocate and Office of Small Business Advocate. TOTI amounts were based
21 on the plan year budget, as adjusted for reasonably known and measurable changes to
22 various payroll taxes as supported by the direct testimony of Ms. Tracy A. Hazenstab (UGI
23 Gas Statement No. 2). These adjustments are shown on UGI Gas Exhibit A (Fully

1 Projected), Schedule D-31. The net adjustment of \$950,000 is brought forward to Schedule
2 D-3, page 2, line 54.

3
4 **B. INCOME TAXES**

5 **Q. Please discuss the Company's claim for income tax expense.**

6 A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Gas
7 Exhibit A (Fully Projected), Schedule D-33. Income tax expense is calculated using the
8 procedures normally followed by the Commission, including the use of debt interest
9 synchronization, the normalization method for accelerated depreciation used in the
10 calculation of federal income taxes, and the flow-through of accelerated depreciation
11 benefits for state income tax purposes. UGI Gas is continuing its practice of normalizing
12 the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas
13 continues to flow through the repairs tax benefit over the tax useful lives of the asset that
14 generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY
15 income tax expense is shown on UGI Gas Exhibit A (Fully Projected), Schedule D-1.

16
17 **Q. Please describe the claim for income taxes shown on Schedule D-1, lines 19 and 20.**

18 A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13
19 and 19. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at
20 present and proposed rates. Schedule D-33, line 1 shows revenue at present and proposed
21 rates, while line 2 shows operating expenses at present and proposed rates from Schedule
22 D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1
23 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule
24 C-1, with the cost of debt and the debt component of UGI Gas's capital structure

1 recommended in the direct testimony of Dylan A. D'Ascendis (UGI Gas Statement No. 8)
2 and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from
3 operating income before interest and taxes to calculate base taxable income on line 7.

4 In accordance with established Commission practice, lines 8 through 11 of
5 Schedule D-33 reduce the base taxable income, for state tax purposes, by the total
6 difference between accelerated tax depreciation shown on line 8 and the *pro forma* book
7 depreciation shown on line 9, which appears as (\$150,731) on line 10. Next, the statutory
8 state corporate net income tax rate was applied (as further described below in Section G of
9 my testimony) to determine the *pro forma* state income tax expense shown on line 13.
10 Regarding the *pro forma* federal income tax expense, lines 14 through 19 show the
11 calculation at current and proposed rates. Next, line 20 sums the state and federal tax
12 expense amounts before application of Deferred Federal and State Income Taxes. At lines
13 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma*
14 income tax expense at present and proposed rates, with the total calculated amount for
15 income taxes, before the application of other adjustments, shown on line 29, which shows
16 the net income tax expense. The amounts of accelerated depreciation, cost of removal,
17 repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book
18 depreciation used in the determination of income taxes are summarized on Schedule D-34.

19
20 **Q. What is the total FPFTY income tax expense for UGI Gas?**

21 A. As shown on Schedule D-33 at line 31, the *pro forma* combined income tax expense at
22 present rates is \$50.2 million and the *pro forma* income tax expense at proposed rates for
23 the FPFTY is \$76.4 million. As explained below in Section E, this figure is not required

1 to be reduced by a consolidated income tax adjustment. Moreover, the pro forma income
2 tax at present rates and the pro forma income tax revenue increase calculated in Schedule
3 D-33 appear in Schedule D-1, which comprises the Company's claimed income tax
4 expense.

5
6 **Q. Has the Company reflected the amortization of Excess Deferred Federal Income**
7 **Taxes ("EDFIT"), as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"), on its**
8 **income tax expense claim?**

9 A. Yes, the Company has calculated the amount of the EDFIT that would be amortized and
10 flowed back to ratepayers in its FPFTY. This amount is included in the overall federal
11 deferred tax expense calculated on line 25 of Schedule D-33. The total amortization was
12 approximately \$5.2 million, calculated using the Average Rate Assumption Method
13 ("ARAM") as required by tax normalization rules.

14
15 **C. ACCUMULATED DEFERRED INCOME TAXES**

16 **Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?**

17 A. Schedule C-6 shows the FPFTY ending balance for federal ADIT as of September 30,
18 2027. This amount is deducted from rate base. The total shown on line 9 reflects the
19 difference in income tax expense for book and tax purposes attributable to the difference
20 between the accelerated tax depreciation and straight-line book depreciation on test year
21 plant balances, net of offsets associated with contributions in aid of construction. Rate
22 base was further reduced by the state regulatory liability associated with UGI Gas's repairs
23 tax method shown on line 6. As the state tax consequence of accelerated depreciation is
24 flowed through, there is no associated state ADIT balance.

1 **Q. What is the amount of the ADIT offset to rate base?**

2 A. As shown on line 9 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is
3 \$716.8 million, which includes the amount related to EDFIT.

4

5 **Q. Does the Company's reduction to rate base include EDFIT?**

6 A. Yes, the Company has reduced its rate base by the unamortized EDFIT, which is
7 incorporated in the ADIT balance on Line 9 of Schedule C-6.

8

9 **Q. Has the Company's ADIT rate base deduction been calculated in compliance with the
10 normalization requirements of the Internal Revenue Code?**

11 A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance
12 with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes
13 to comply with IRS normalization requirements. To qualify for normalization, the IRS
14 requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the
15 Company accrues ADIT for plant additions throughout the year. See UGI Gas Exhibit
16 DTE-2 for the calculation of the pro-rata adjustment.

17

18 **D. REPAIRS TAX METHOD**

19 **Q. Please explain UGI Gas's accounting treatment of the Repairs Tax Method.**

20 A. In its tax return for the year ended September 30, 2009, UGI Gas adopted a tax accounting
21 method to expense as repairs certain items capitalized for book purposes in accordance
22 with federal tax regulations. As it did in the Company's previous base rate case at Docket
23 No. R-2025-3059523, UGI Gas chose to normalize its federal income tax expense claim,
24 inclusive of the repairs tax deduction. The difference between accelerated tax depreciation

1 versus book depreciation in the calculation of federal tax expense creates ADIT. For state
2 income tax purposes, solely with respect to the repairs tax deduction, UGI Gas has chosen
3 to flow through the repairs tax benefit over the tax useful lives of the assets generating the
4 tax deduction. The state ADIT balance associated with the repairs tax deduction is
5 classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers
6 have not yet received. In both the federal and state instances, the ADIT balance amortizes
7 or unwinds over the remaining life of the asset.

8 As noted previously, the Company reduces rate base by the sum of the federal ADIT
9 balance and the state repair regulatory liability.

10
11 **Q. Has UGI Gas adopted the new IRS safe harbor accounting method guidance under**
12 **Revenue Procedure (Rev. Proc.) 2023-15 for determining qualified repairs**
13 **deductions?**

14 **A** Yes, effective for tax year September 30, 2024, UGI Gas adopted the safe harbor method
15 under Rev. Proc 2023-15 for purposes of determining the applicable repairs deduction for
16 tax purposes. These results are the basis for the estimated repairs deductions used in this
17 rate case. The adoption of the new guidance only clarifies what expenditures qualify as
18 tax deductions. There has been no change in the Company's accounting treatment of repair
19 deductions.

1 **E. CONSOLIDATED TAX BENEFITS**

2 **Q. Does the Company’s proposed revenue requirement reflect a federal consolidated tax**
3 **expense adjustment?**

4 A. No. The Company’s revenue requirement is established based on its stand-alone federal
5 income tax attributes. It is also my understanding that Act 40 of 2016, which added 66 Pa.
6 C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax
7 adjustment for ratemaking purposes. Moreover, it is my understanding that the
8 requirements of Section 1301.1(b) no longer apply pursuant to Section 1301.1(c) as of
9 December 31, 2025. Thus, the Company has not calculated a hypothetical consolidated
10 tax adjustment for purposes of Section 1301.1(b).

11
12 **F. DEVELOPMENT TAX CREDITS**

13 **Q. Does UGI Gas claim a Development Tax Credit on its tax return?**

14 A. Yes, UGI Gas claims a development tax credit on its federal income tax return under
15 Internal Revenue Code Section 41. Qualifying activities for the Development Tax Credit
16 are those that are intended to develop or improve the functionality, performance, reliability,
17 or quality of a new or existing business product, process, technique, formula, invention or
18 software. The activity must be technological in nature, have technical uncertainty and
19 involve a process of experimentation. The credit was first claimed on the Company’s
20 federal income tax return for the year ended September 30, 2022, which was filed in 2023.
21 For the purpose of this case, prior years’ results were used to estimate the future benefit of
22 the tax credit anticipated in the FPFTY. The benefit of \$275,000 is included with the
23 investment tax credit on line 30, of Schedule D-33.

1 **G. PENNSYLVANIA TAX RATE CHANGE**

2 **Q. Are you familiar with the Pennsylvania corporate net income tax rate change?**

3 A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which reduced the state
4 corporate net income tax rate from the then-current 9.99% to 4.99% over a nine-year
5 period. The initial reduction to 8.99% was effective for tax years beginning in calendar
6 year 2023. Thus, the initial reduction applied to Fiscal Year End September 30, 2024.

7
8 **Q. How has the Company accounted for the recently enacted Pennsylvania tax rate
9 change?**

10 The Company’s claim for income taxes reflects the applicable state tax rate in effect for
11 the HTY (i.e., 8.49%), FTY (i.e., 7.99%) and FPFTY (i.e., 7.49%). As explained above,
12 the initial reduction applied to our HTY. The State Tax Adjustment Surcharge (“STAS”)
13 mechanism will adjust the Company’s rates as applicable for future reductions to the state
14 corporate net income tax rate.

15
16 **Q. How is the Company applying the Pennsylvania corporate net income tax rate change
17 to its Repairs Tax method?**

18 A. Consistent with historic treatment as described in Section D of this testimony, the
19 Company’s state regulatory liability associated with its repairs tax method will continue to
20 represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

21
22 **Q. Does this conclude your direct testimony?**

23 A. Yes, it does.

UGI GAS

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA
Senior Manager of Natural Gas Tax Accounting

March 2022 - Present

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. Manage 1 direct report.

JBS USA, Greeley, CO
Senior Tax Manager, Tax Accounting and Global Reporting

2014 - March 2022

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
Senior Tax Analyst

2007 to 2014

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
Senior Associate

2000 to 2007

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
Senior Associate

1994 to 2000

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 Base Rate Case

Docket No. R-2024-3052716

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	Deferred Income Tax Balance
9/30/2026					\$	708,090
10/31/2026	3,000	335	91.78%	2,753		710,843
11/30/2026	926	305	83.56%	774		711,617
12/31/2026	1,214	274	75.07%	912		712,529
1/31/2027	614	243	66.58%	409		712,938
2/28/2027	646	215	58.90%	380		713,318
3/31/2027	1,728	184	50.41%	871		714,189
4/30/2027	750	154	42.19%	316		714,506
5/31/2027	926	123	33.70%	312		714,818
6/30/2027	3,633	93	25.48%	926		715,743
7/31/2027	2,638	62	16.99%	448		716,192
8/31/2027	1,863	31	8.49%	158		716,350
9/30/2027	7,585	1	0.27%	21	\$	716,371

UGI GAS STATEMENT NO. 10

SHERRY A. EPLER

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 10

**Direct Testimony of
Sherry A. Epler**

**Topics Addressed: Test Year Sales and Revenues
Tariff Changes**

Dated: January 28, 2026

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q. Please state your name and business address.**

3 A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

4
5 **Q. By whom and in what capacity are you employed?**

6 A. I am employed as Senior Manager, Tariff & Supplier Administration, by UGI Utilities, Inc.
7 (“UGI”). UGI has both a Gas Division (“UGI Gas”), which is a certificated natural gas
8 distribution company (“NGDC”), and an Electric Division (“UGI Electric”), a certificated
9 electric distribution company (“EDC”).

10
11 **Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration
12 with respect to UGI Gas?**

13 A. My current responsibilities related to UGI Gas include: (1) all aspects of tariff and rate
14 administration, including certain interactions with natural gas suppliers under UGI Gas’s
15 supplier tariff; and (2) revenue analysis.

16
17 **Q. Please provide your educational background.**

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

19
20 **Q. Please provide your professional experience.**

21 A. I have worked for UGI since 1986, supporting the Accounting and Rates groups in varying
22 capacities. Please see my resume, UGI Gas Exhibit SAE-1, for my full employment
23 history.

1 **Q. Please describe the purpose of your testimony.**

2 A. I will address: (1) the development of sales and revenue for the historic test year ended
3 September 30, 2025 (“HTY”), future test year ending September 30, 2026 (“FTY”), and
4 fully projected future test year ending September 30, 2027 (“FPFTY”); and (2) certain
5 proposed tariff modifications.

6
7 **Q. Are any other witnesses providing testimony on the areas you identified above?**

8 A. Yes. Company witness John D. Taylor, who is employed as Managing Partner by Atrium
9 Economics, LLC (UGI Gas Statement No. 11), is sponsoring allocation of the proposed
10 revenue increase and rate design, in addition to his other testimony topics, using the
11 projected sales and revenue figures discussed in my testimony.

12
13 **Q. Are you sponsoring any exhibits or filing requirements in this proceeding?**

14 A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit SAE-1 (Resume), UGI Gas
15 Exhibit SAE-2 (10 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3
16 (Normalized Multi-Year and Normalized 12-Month Ending Trends of Use Per Customer
17 for Residential and Commercial Heating), UGI Gas Exhibit SAE-4 (Fully Projected Future
18 Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-5 (Future Test Year
19 Sales and Revenue Adjustments), UGI Gas Exhibit SAE-6 (Historic Test Year Sales and
20 Revenue Adjustments), UGI Gas Exhibit SAE-7 (Fully Projected Future Test Year, Future
21 Test Year, and Historic Test Year Usage Per Customer Detail by Class), UGI Gas Exhibit
22 SAE-8 (No Notice Service (“NNS”) Rate Calculation), UGI Gas Exhibit SAE-9 (Monthly
23 Balancing Service (“MBS”) Rate Calculation), UGI Gas Exhibit SAE-10 (Rider D-

1 Merchant Function Charge (“MFC”) Calculation), certain portions of UGI Gas Exhibit F
2 (Proposed Tariff), and UGI Gas Exhibit E (Proof of Revenue). I am also sponsoring certain
3 responses to the Commission’s standard filing requirements, as indicated on the master list
4 accompanying this filing, that were prepared by me or under my direction.
5

6 **II. TEST YEAR SALES AND REVENUE**

7 **Q. Please explain how the Company’s FPFTY sales and revenues were developed.**

8 A. FPFTY sales and revenues were developed by incorporating annualizing and normalizing
9 adjustments to the Company’s 2027 fiscal year sales and revenue budgets to reflect end of
10 FPFTY conditions for ratemaking purposes. The development of the initial sales and
11 revenue budgets which were utilized as the starting point prior to adjustments is described
12 in the testimony of Vivian K. Ressler (UGI Gas Statement No. 4). Where similar
13 adjustments are made across rate class groups, the methodology applied to develop
14 normalized use per customer adjustments (for the FPFTY, FTY, and HTY) to budget values
15 is the same for all three periods to present sales and revenue on a comparable ratemaking
16 basis. A summary of projected use per customer by class group for the FPFTY, FTY, and
17 HTY is included in UGI Gas Exhibit SAE-7. The projected Residential Heating use per
18 customer was established for Rate R/RT-Heating per the UGI Gas model detailed in SDR-
19 RR-11. Since, over time, switching occurs on a regular basis between residential Rates R
20 (retail service) and RT (transportation service), the regression analysis was performed on
21 a total Rate R/RT basis to eliminate potential switching impacts that could distort use per
22 customer analyses. More detail on this regression analysis is provided below as part of the
23 discussion related to the Company’s “Adjustment for Normalized & Annualized

1 Use/Customer.” Weather normalized sales for Rate RT-Heating customers for the 12
2 months ended September 30, 2025, were then utilized to mathematically derive the separate
3 Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per
4 customer regression value).

5 Actual sales were normalized for Rate R-Non-Heating and Rate RT-Non-Heating,
6 in total, for the 12-month period ended September 30, 2025, to eliminate potential
7 switching impacts that could distort use per customer analyses. These data were used to
8 project combined Rate R/RT-Non-Heating use per customer in total. Weather normalized
9 sales for Rate RT-Non-Heating customers for the 12 months ended September 30, 2025,
10 were then utilized to mathematically derive the separate Rate R-Non-Heating customer
11 values (from the combined Rate R/RT-Non-Heating use per customer value).

12 The projected Commercial Heating use per customer was established on a
13 combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression
14 techniques detailed in SDR-RR-11. Given that, over time, switching occurs on a regular
15 basis between Rates N (retail service), NT (transportation service) and DS (transportation
16 service), the regression analysis was performed on a total Rates N/NT/DS basis to eliminate
17 potential switching impacts that could distort use per customer analyses. More detail on
18 this regression analysis is provided below as part of the discussion related to the
19 Company’s “Adjustment for Normalized & Annualized Use/Customer.” To separate the
20 combined Rate N/NT/DS-Commercial Heating value into respective Rate N, Rate NT and
21 Rate DS values, Rate NT-Commercial Heating use per customer was established on the
22 basis of weather normalized sales for Rate NT-Commercial Heating customers, for the 12
23 months ended September 30, 2025, as this class is much smaller in number than the Rate

1 N-Commercial Heating class. Rate DS-Commercial Heating use per customer was then
2 established based on budgeted 2027 sales for Rate DS-Commercial Heating, as Rate DS
3 budgeting was performed on a detailed per-customer level. These Rate NT and Rate DS
4 Commercial Heating values were then utilized to mathematically derive the Rate N-
5 Commercial Heating use per customer values (from the combined Rates N/NT/DS-
6 Commercial Heating use per customer value).

7 Actual sales were normalized for Rate N-Commercial Non-Heating, Rate NT-
8 Commercial Non-Heating and Rate DS-Commercial Non-Heating, in total, to reflect the
9 12 months ended September 30, 2025, in order to project combined Rates N/NT/DS-
10 Commercial Non-Heating use per customer in total and eliminate potential switching
11 impacts that could distort use per customer analyses. To separate the combined Rate
12 N/NT/DS-Commercial Non-Heating value into respective Rate N, Rate NT and Rate DS
13 values, Rate NT-Commercial Non-Heating was based on weather normalized sales for Rate
14 NT-Commercial Non-Heating, for the 12 months ended September 30, 2025, and Rate DS-
15 Commercial Non-Heating was based on budgeted 2027 sales for Rate DS-Commercial
16 Non-Heating, which were done on a per-customer level. These Rate NT and Rate DS
17 values were then utilized to mathematically derive the Rate N-Commercial Non-Heating
18 use per customer values (from the combined Rates N/NT/DS-Commercial Non-Heating
19 use per customer value).

20 Actual sales were normalized for Rate N-Industrial, Rate NT-Industrial, and Rate
21 DS-Industrial to reflect the 12 months ended September 30, 2025, in order to project
22 combined Rates N/NT/DS-Industrial use per customer in total and eliminate potential
23 switching impacts that could distort use per customer analyses. To separate the combined

1 Rate N/NT/DS-Industrial value into respective Rate N, Rate NT and Rate DS values, Rate
2 NT-Industrial was based on weather normalized sales for Rate NT-Industrial for the 12
3 months ended September 30, 2025. Rate DS-Industrial was based on budgeted 2027 sales
4 for Rate DS-Industrial, which were done on a per-customer level. These Rate NT and Rate
5 DS values were then utilized to mathematically derive the Rate N-Industrial use per
6 customer value (from the combined Rates N/NT/DS-Industrial use per customer value).

7
8 **Q. How was temperature accounted for in developing sales and revenue forecasts?**

9 A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree
10 days ("HDDs") of 5,218. This annual normal HDD calculation is derived from a
11 composite, sales-weighted value (by system demand) for each of the Company's four
12 delivery regions, and the respective normal heating degree values. As proposed in this
13 proceeding, and discussed in the Direct Testimony of John D. Taylor, UGI Gas Statement
14 No. 11, normal HDDs are now defined based upon an average over a 10-year period with
15 the most recent update of the 10-year period ending December 31, 2024. UGI Gas Exhibit
16 SAE-2 provides supporting detail by year for the 10-year normal HDDs. Please see the
17 Direct Testimony of John D. Taylor, UGI Gas Statement No. 11 for supporting detail on
18 the determination of Normal HDD values and the frequency of Normal HDD updates.

19
20 **Q. Please describe the adjustments made to the budget for the 12 months ending
21 September 30, 2027, to develop FPFTY sales and revenues.**

22 A. A summary of all adjustments made to the 2027 budget to develop FPFTY sales and
23 revenue is shown on UGI Gas Exhibit SAE-4(a). Detail for each of these adjustments is

1 provided on subsequent worksheets labeled 4(b) through 4(m). In total, these adjustments
2 reflect a decrease to sales of 4,382 MMcf and a decrease to revenue of \$49.761 million,
3 inclusive of Purchased Gas Cost (“PGC”) revenues.

4
5 **Q. Please explain the “Adjustment for Customer/Contract Changes” shown on UGI Gas**
6 **Exhibit SAE-4(a).**

7 A. The “Adjustment for Customer/Contract Changes” annualizes customer counts to
8 anticipated end-of-test-year levels based on the Company’s most recent forecast for the
9 FPFTY; it is inclusive of any large transportation contract customer changes related to
10 customers served under Rates LFD, XD, and IS. In particular, among other adjustments,
11 this adjustment includes a net decrease of 3,925 Residential Heating customers (Rate R)
12 from budgeted levels to anticipated end-of-test-year levels and a net decrease of 1,338
13 Commercial Heating customers (Rate N) from budgeted levels to anticipated end-of-
14 FPFTY levels on September 30, 2027.

15
16 **Q. How were these adjustments calculated?**

17 A. UGI Gas Exhibit SAE-4(b) provides the calculation of the associated sales and revenue
18 adjustments for the stated customer counts. In total, these adjustments decrease sales by
19 834 MMcf and decrease projected revenues by \$11.756 million, inclusive of PGC
20 revenues. Additional detail for column (9) of UGI Gas Exhibit SAE-4(b) can be found on
21 UGI Gas Exhibit SAE-4(b)(1), which provides a breakout of customer data for large
22 transportation customer classes.

1 **Q. Please explain the adjustment titled “Adjustment for Customer/Contract Changes –**
2 **Large Transport and Interruptible Detail” as shown on UGI Gas Exhibit SAE-**
3 **4(b)(1).**

4 A. Adjustments for large transportation customers are developed by UGI Gas’s marketing
5 personnel following their review of individual large customer accounts and market
6 segments. The adjustments reflect annualizing anticipated increases or reductions from
7 original individual customer budgeted sales and revenues. Given there were no known
8 changes since the development of the original budget, there are no quantified adjustments
9 to the original budget for the Large Transport and Interruptible customers shown on UGI
10 Gas Exhibit SAE-4(b)(1).

11
12 **Q. Please explain your next adjustment, “Adjustment for Normalized & Annualized**
13 **Use/Customer” shown on UGI Gas Exhibit SAE-4(a) and detailed on UGI Gas**
14 **Exhibit SAE-4(c).**

15 A. The “Adjustment for Normalized & Annualized Use/Customer” normalizes and annualizes
16 usage per customer to projected end-of-test-year levels. Specifically, in developing usage
17 per customer projections for the Company’s core Residential Heating rate groups (Rates R
18 and RT), the Company utilized an econometric regression model that incorporates four
19 independent variables: (1) use per customer; (2) HDDs; (3) lagged HDDs; and (4) weighted
20 time trend. While use per customer, HDDs, and lagged HDDs capture weather related
21 usage factors, which can then be used to project normalized and annualized customer usage
22 under normal weather conditions, the weighted time trend variable of this regression
23 captures non-weather trends that underlie changes in usage per customer over time (*e.g.*,

1 conservation). These trends can vary, but as a comprehensive variable, “trend” will capture
2 the impacts of conservation, including but not limited to: (1) regular appliance
3 replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance
4 installations; (4) setback thermostat installations; (5) modifications to new and existing
5 buildings that are designed to decrease energy consumption; and (6) changes in consumer
6 usage behavior due to other economic influences. Given the number of variables that can
7 influence customer usage over time, and the difficulty in identifying, quantifying, and
8 tracking all variables over time, a trend variable is used to provide a comprehensive
9 indicator of usage trends, which can then be used to forecast for a future period.
10 Additionally, the trend variable is weighted by HDDs to reflect a “weighted trend,” which
11 more accurately reflects that the trends’ impacts are directly related to usage during heating
12 time periods.

13 For the Residential Heating groups of Rates R and RT, the multi-year period
14 regression methodology is the same base method that the Company has utilized in prior
15 rate cases, updated for the use of a common data set period beginning October 2003
16 through, now, September 2025. October 2003 is the earliest common data set available for
17 the entire service territory, given the timing and data availability of historic service and
18 former rate district level details for UGI Gas and its former subsidiaries, UGI PNG and
19 UGI CPG.

20 For the Company’s core Commercial Heating rate groups (inclusive of Rates N,
21 NT, and DS), the Company utilized the same regression method as presented in UGI Gas’s
22 2019, 2020, 2022, and 2025 Gas Base Rate Cases. Specifically, to forecast the Commercial
23 Heating rate group use per customer, the Company utilized three variables: (1) use per

1 customer; (2) HDDs; and (3) lagged HDDs. For the Commercial Heating group, the
2 Company used the period beginning October 2012 through, now, September 2025 for
3 regression modeling, or the entire period during which common non-residential rate
4 structures existed for UGI Gas and its former subsidiaries.

5 The forecasts for end-of-FPPTY use per customer are generated using the
6 regression results along with a projection of regression variable inputs, including normal
7 annual HDDs and, where applicable, a weighted trend variable. The results are presented
8 in summary on UGI Gas Exhibit SAE-4(a) and in detail on UGI Gas Exhibit SAE-4(c). In
9 total, the result is a net sales decrease, from the fiscal 2027 budget, of 3,308 MMcf, and a
10 net revenue decrease, from the fiscal 2027 budget, of \$37,090 million, inclusive of PGC
11 revenues.

12
13 **Q. Why did UGI Gas utilize a multi-year regression period?**

14 A. The Company has continued to use the multi-year period because it provides a larger
15 sample set of data to smooth out short-term variations and capture the underlying long-
16 term use per customer trends. Consequently, the multi-year regression period more
17 accurately projects usage per customer during the period rates are likely to be in effect.
18 This methodology is consistent with that utilized in the last nine base rate cases of UGI
19 Gas and its predecessor entities.

1 **Q. Has UGI Gas compared the results of the multi-year regression method to develop**
2 **normalized usage for Residential Heating and Commercial Heating customer groups**
3 **with any other normalization method?**

4 A. Yes. Please see UGI Gas Exhibits SAE-3(a) and SAE-3(b), which contain use per
5 customer graphs that illustrate the results of both the multi-year normalized regression
6 method I have explained above (“Normalized Multi-year”) and a short-term normalized
7 (“Normalized 12 Months ended”) value for the same groups of Residential Heating and
8 Commercial Heating customers. The short-term normalized values are computed via a
9 simple determination of temperature sensitive load each month during the 12 month period
10 ending September 30, 2025. As can be seen from these graphs, short-term trend
11 fluctuations of the “Normalized 12 months ended” line occur in certain periods, but
12 consistently revert to the long-term “Normalized Multi-year” trend which has been used to
13 forecast FPFTY use per customer values, thus capturing the ongoing base trend in declining
14 use per customer.

15
16 **Q. Please explain the “Adjustment for PGC” shown on UGI Gas Exhibit SAE-4(a) and**
17 **detailed on UGI Gas Exhibit SAE-4(d).**

18 A. The “Adjustment for PGC” shown in summary on UGI Gas Exhibit SAE-4(a) annualizes
19 FPFTY PGC revenues using the PGC rate in effect as of December 1, 2025. UGI Gas
20 Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment
21 increases PGC revenues for the FPFTY by \$1.938 million.

1 **Q. Please explain the following three adjustments shown in summary on UGI Gas**
2 **Exhibit SAE-4(a): “Adjustment for MFC,” “Adjustment for USP,” and “Adjustment**
3 **for GPC.”**

4 A. The “Adjustment for MFC” annualizes the Company’s Merchant Function Charge
5 (“MFC”) revenues for the FPFTY based on the MFC surcharge rates in effect as of
6 December 1, 2025. The MFC Adjustment increases projected revenues by \$0.039 million.

7 The “Adjustment for USP” annualizes the Company’s Universal Service Program
8 (“USP”) surcharge revenues for the FPFTY based on the USP Rider rate in effect as of
9 December 1, 2025. The Adjustment for USP also updates the sales volume for Customer
10 Assistance Program (“CAP”) customers in the USP Revenue calculation with end of Fiscal
11 Year 2025 data in comparison to the budgeted sales volume for CAP customers, which was
12 calculated using end of Fiscal Year 2024 data. The USP adjustment decreases revenues by
13 \$0.480 million.

14 The “Adjustment for GPC” annualizes the Gas Procurement Cost (“GPC”) revenues
15 to reflect the impact of all volume adjustments to the original Fiscal Year 2027
16 planned budget. The GPC adjustment decreases revenues by \$0.257 million. Additional
17 details for these three adjustments are provided in UGI Gas Exhibit SAE-4(e), UGI Gas
18 Exhibit SAE-4(f), and UGI Gas Exhibit SAE-4(g), respectively.

19

20 **Q. Please explain “Adjustment for Excess Take Revenues” as shown on UGI Gas Exhibit**
21 **SAE-4(a).**

22 A. The “Adjustment for Excess Take” shown on UGI Gas Exhibit SAE-4(a) is detailed in UGI
23 Gas Exhibit SAE-4(h) and reflects the assumption that large transportation customers will

1 evaluate new service elections and will make the necessary adjustments to avoid Excess
2 Take penalties in the FPFTY. The Excess Take adjustment reduces revenue by \$1.7
3 million.

4
5 **Q. Please explain “Adjustment for STAS” as shown on UGI Gas Exhibit SAE-4(a).**

6 A. The “Adjustment for STAS” shown on UGI Gas Exhibit SAE-4(a) is detailed in UGI Gas
7 Exhibit SAE-4(i) and annualizes the revenue for the State Tax Adjustment Surcharge
8 (“STAS”) for the FPFTY based on the STAS Rider rate in effect as of December 1, 2025.
9 This adjustment increases revenues by \$0.116 million.

10
11 **Q. Please explain the “Adjustment for EEC Rider” on UGI Gas Exhibit SAE-4(a).**

12 A. The “Adjustment for EEC Rider” annualizes the revenue from the Energy Efficiency and
13 Conservation (“EE&C”) Rider (“EEC Rider”) for the FPFTY based on the EEC Rider rate
14 in effect as of December 1, 2025. This adjustment decreases revenues by \$0.001 million
15 and is detailed on UGI Exhibit SAE-4(j).

16
17 **Q. Please explain the “Adjustment for EEC Conservation Impact” on UGI Gas Exhibit
18 SAE-4(a).**

19 A. The “Adjustment for EEC Conservation Impact” annualizes the impact to revenues from
20 UGI Gas’s ongoing EE&C programs and associated reduced energy consumption as a
21 result of measures implemented as part of the EE&C programs. This adjustment decreases
22 FPFTY sales by 240 MMcf and decreases revenues by \$3.000 million as detailed on UGI
23 Gas Exhibit SAE-4(k).

1 **Q. Please explain the “Adjustment for GDE Rider” on UGI Gas Exhibit SAE-4 (a).**

2 A. The “Adjustment for GDE Rider” annualized the revenue for the Gas Delivery
3 Enhancement (“GDE”) Rider for the FPFTY based on GDE Rider rate in effect as of
4 December 1, 2025. This adjustment decreases revenues by \$0.185 million and is detailed
5 on UGI Gas Exhibit SAE-4(l).

6
7 **Q. Please explain the “Adjustment for DSIC” on UGI Gas Exhibit SAE-4(a).**

8 A. The “Adjustment for DSIC” annualizes Distribution System Improvement Charge
9 (“DSIC”) revenue based on the application of the 0.33% DSIC E-Factor rate in effect as of
10 December 1, 2025, to FPFTY revenues. The FPFTY budget utilized a rate of 0.0%. This
11 adjustment applies a 0.33% DSIC rate in order to annualize the DSIC to end of FPFTY
12 conditions. The 0.33% rate is currently projected to be effective at the end of the FTY, and
13 that 0.33% rate will remain in place through the FPFTY period. This allows the Company
14 to properly quantify DSIC revenues, which will be rolled into the new base rates
15 established in this proceeding as a result of re-setting the DSIC rate to zero pursuant to 66
16 Pa. C.S. § 1358(b)(1). This adjustment increases revenues by \$2.615 million and is shown
17 in detail on UGI Gas Exhibit SAE-4(m).

18
19 **Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and
20 non-jurisdictional revenue?**

21 A. Yes. Pursuant to the terms of the Revenue Sharing Incentive Mechanism in Section 11 of
22 the UGI Gas tariff, these revenues are appropriately treated as below the line for ratemaking
23 purposes and, thus, have been excluded.

1 **III. DEVELOPMENT OF SALES AND REVENUES FOR THE FTY AND HTY**

2 **Q. How were normalized and annualized sales and revenues determined for the FTY?**

3 A. Budgeted sales and revenues serve as the starting point for developing the normalized and
4 annualized FTY sales and revenues, as shown in UGI Gas Exhibit SAE-5. All of the
5 adjustments that were made in the development of the FPFTY sales and revenues were also
6 made in the development of the FTY sales and revenues, with the exception of the
7 adjustments for the EEC Conservation Impact that are contained in the FPFTY but not the
8 FTY.

9
10 **Q. How were normalized and annualized sales and revenues determined for the HTY?**

11 A. Historic sales and revenues serve as the starting point for developing the normalized and
12 annualized HTY sales and revenues shown in UGI Gas Exhibit SAE-6. All of the
13 adjustments that were made in the development of the FPFTY were also made in the
14 development of the HTY, with the exception of the adjustments for the Weather
15 Normalization Adjustment (“WNA”), EEC Conservation Impact, GDE Rider, and DSIC.
16 The “Adjustment for WNA” in the HTY removes the revenues associated with the actual
17 WNA revenue recorded in the HTY revenues and margins in order to not double count
18 certain weather-related impacts, as the Adjustment for Normalized & Annualized
19 Use/Customer fully incorporates weather related usage impacts. The EEC Conservation
20 Impact is not required, as the actual HTY sales and revenue reflect such impacts. The
21 adjustments for the GDE Rider and the DSIC are discussed above.

1 **Q. Is the Company proposing any change to the rate assessed under Rate NNS (No Notice**
2 **Service)?**

3 A. For the reasoning stated below, the Company is proposing to retain the current Rate NNS
4 service rates at this time and not recalculate those rates. Rate NNS is a daily balancing
5 service offered by the Company. It provides an alternate election of a daily balancing
6 tolerance for transportation customers, allowing a customer to optionally elect a balancing
7 tolerance greater than the standard basic balancing provided by the Company. A customer
8 is able to make an election under Rate NNS up to its DFR (Daily Firm Requirement)
9 contract demand level and pay only for the level chosen. The revenue generated by Rate
10 NNS charges is reflected as a credit to PGC rates, because the capacity used for this service
11 is otherwise paid for by PGC customers.

12
13 **Q. How has UGI Gas historically approached the updating of Rate NNS?**

14 A. As part of the settlement of its 2019 Gas Base Rate Case, the parties agreed to a
15 methodology for calculating Rate NNS (see Joint Petition for Approval of Unopposed
16 Settlement of All Issues, paragraph No. 53, filed on July 22, 2019, at Docket Nos. R-2018-
17 3006814, *et al.*, which was approved by the Commission’s Opinion and Order entered on
18 October 4, 2019, in that proceeding). In cases since the 2019 Gas Base Rate Case, UGI
19 Gas has used the methodology specified to calculate a rate – consistently a rate decrease –
20 and has proposed that rate decrease in its filed case. In each of those cases, UGI Gas has
21 met strong opposition to its proposal. If the Company were to update the tariffed Rate
22 NNS charge to reflect current cost elements in this case, using the 2019 Gas Base Rate
23 Case methodology, the Company would be proposing a decrease to Rate NNS. However,

1 as noted above, the Company is proposing to retain the current Rate NNS rate. However,
2 as noted above, the Company is proposing to retain the current Rate NNS rate.

3
4 **Q. Why is the Company proposing to retain the current Rate NNS rate in this case?**

5 A. UGI Gas believes that the use of the service by customers over time indicates that the
6 current rate, which has been in place since 2019, is appropriately priced for the value it
7 delivers to participating customers, while also providing stable affordability benefits to
8 PGC customers. Importantly, the Company's actions in this regard recognize the historic
9 cost assignment methodology differences between the Company and certain of the public
10 advocates. UGI Gas believes its Rate NNS approach in this proceeding balances the
11 interests of different customer classes.

12
13 **Q. Has the Company shown the development of the recalculated Rate NNS charge, even
14 though it is not proposing to change Rate NNS?**

15 A. UGI Gas Exhibit SAE-8 shows the recalculation of the Rate NNS charge. Again, this
16 recalculation was developed based on the same methodology used in the Company's 2019
17 Gas Base Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate would
18 be \$0.1700 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity.
19 This compares to the current NNS rate of \$0.2200 per Mcf/d of elected NNA, which was
20 established in the Company's 2022 Gas Base Rate Case (see Paragraph 44 in the
21 Recommended Decision issued on July 28, 2022 at Docket Nos. R-2021-3030218, *et al.*);
22 the current rate was also retained in the Company's 2025 Gas Base Rate Case at Docket
23 No. R-2024-3052716, in Paragraph 55 of the Commission-approved Joint Petition for

1 Settlement of All Issues dated July 10, 2025. This current rate is proposed to be retained
2 as part of this initial filing.

3
4 **Q. Will the Company continue to credit the revenues received from Rate NNS to PGC
5 Rates?**

6 A. Yes, revenues from Rate NNS will continue to be credited to the PGC Rates as part of the
7 Company's annual 1307(f) proceeding.

8
9 **Q. Please describe Rate MBS (Monthly Balancing Service).**

10 A. Rate MBS is a monthly balancing service offered by the Company. Service under Rate
11 MBS allows transportation imbalances of up to 10% for the month to be carried forward in
12 the customer's MBS account for delivery of excess volumes, or receipt of shortfalls, in
13 subsequent months.

14
15 **Q. Has the Company proposed any changes to the Rate MBS rates?**

16 A. Yes. UGI Gas Exhibit SAE-9 provides the basis for the MBS rate calculation. As a result
17 of the settlement in the Company's 2019 Gas Base Rate Case, storage demand charges
18 were included in the calculation of Rate MBS on a 100% load factor basis and the Company
19 is continuing that inclusion in the proposed rates presented. The MBS rate is updated
20 annually on December 1st each year, using 12 months of data ending in September, for the
21 average monthly imbalance utilized in development of the rate. The MBS rates most
22 recently updated for December 1, 2025, are: \$0.0177/Mcf for Rates DS and IS;
23 \$0.0103/Mcf for Rate LFD; and \$0.0104/Mcf for Rate XD. As seen on UGI Gas Exhibit

1 SAE-9, the proposed MBS rates will be: \$0.0198/Mcf for Rates DS and IS; \$0.0113/Mcf
2 for Rate LFD; and \$0.0116/Mcf for Rate XD. These Rate MBS increases are principally
3 driven by increases to the average capacity charge.
4

5 **Q. Will the Company continue to credit the revenues received from Rate MBS to PGC**
6 **Rates?**

7 A. Yes, revenues from Rate MBS will continue to be credited to the PGC as part of the
8 Company's annual 1307(f) proceeding.
9

10 **Q. Please describe the GPC.**

11 A. The GPC recovers costs associated with gas procurement that were unbundled from base
12 rates.
13

14 **Q. Is the Company proposing to update its GPC in this proceeding?**

15 A. No. The Company proposes to continue the \$0.0660/Mcf blended rate that was approved
16 in the Company's 2020 Gas Rate Case (see Joint Petition for Approval of Unopposed
17 Settlement of All Issues, Appx. A, p. 12, filed on August 3, 2020, at Docket Nos. R-2019-
18 3015162, *et al.*, which was approved by the Commission's Opinion and Order entered on
19 October 8, 2020, in that proceeding).
20

21 **Q. Please describe the MFC.**

22 A. The MFC is equal to the fixed percentage of purchased gas costs that are expected to be
23 uncollectible.

1 **Q. Is the Company proposing to update its MFC in this proceeding?**

2 A. Yes. The Company is updating the percentages for the MFC rates to reflect the actual
3 uncollectible expense for the last three years. Based on this updated data, the residential
4 MFC will be 2.37%, and the MFC for the commercial class will be 0.47%. Please see UGI
5 Gas Exhibit SAE-10 for additional details.

6
7 **Q. Please describe the USP Rider.**

8 A. The USP Rider recovers those costs associated with the provision of universal service
9 offerings approved by the Commission in the Company's Universal Service and Energy
10 Conservation Plan.

11

12 **Q. Is the Company proposing any changes to the USP Rider?**

13 A. Yes. The Company is proposing changes to the annual reconciliation provisions of Rider
14 F – Universal Service Program “USP” to update the threshold number of customers
15 enrolled in CAP that is used in the calculation of the offset applied to recoverable CAP
16 costs. This offset reduces the Company's recovery of CAP spending above projected
17 enrollment to account for write-offs of bad debt that would arguably have occurred if not
18 for CAP. The Company proposes to set the CAP enrollee threshold equal to the number
19 of CAP participants as of September 30, 2026, to provide an enrollee figure that reflects
20 the actual ongoing impacts on CAP enrollment. This proposal is consistent with the
21 establishment of the CAP enrollee figure in the UGI Gas 2020 Rate Case at Docket No. R-
22 2019-3015162.

1 **IV. TARIFF CHANGES**

2 **Q. What tariff changes are being proposed in this case?**

3 A. The Company is revising references to the Supplement number, Notice language, Issue and
4 Effective dates, and page numbers as necessary per this case. Apart from the proposed rate
5 schedule changes, a complete list of tariff modifications can be found in the List of Changes
6 Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 63 to
7 UGI Gas Tariff No. 7 and Proposed Supplement No. 63 to UGI Gas Tariff No. 7S. More
8 significant proposed changes to the tariffs include:

- 9 • Rule 8.4, Billing and Payment, has clarifying language added to explain that Budget
10 Billing will be reviewed and adjusted on a quarterly basis .
- 11 • Section 8.14 was added to specify the acceptable and Applicable Forms of Payment
12 that customers may remit to the Company for payment of public utility service.
- 13 • The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset
14 to 0.00%.
- 15 • Rider C, Weather Normalization Adjustment, applicability has been updated to
16 continue as a pilot ending on October 31, 2032, in place of the existing October 31,
17 2027, date. In Calculation of Adjustment Amount, subsection (d), the Weather
18 Normalization Adjustment NHDD has been changed to the Delivery Region’s 10-
19 year average in place of the existing 15-year average for the given day.
20 Additionally, NHDD has been changed to being updated at every rate case in place
21 of the existing 5 years.
- 22 • Rider D – MFC has been set to 2.37% for PGC Residential Customers and 0.47%
23 for Non-Residential PGC Customers, as described above.

- 1 • Section 15. Price to Compare (“PTC”) has been updated to reflect changes to the
2 MFC.
- 3 • Rider F – Universal Service Program has been revised so that the CAP credit bad
4 debt offset will be associated with the participants in excess of the number of CAP
5 enrollees as of September 30, 2026, in place of the existing September 30, 2025
6 date.
- 7 • Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b)(1).
- 8 • Rule 16 – USP Rider has been updated to reflect that the 9.2% adjustment element
9 contained in the Annual Reconciliation shall apply to the actual number of CAP
10 enrollees as of September 30, 2026, in order to appropriately track related costs for
11 recovery between the Rider and base rates. Additionally, language has been added
12 to allow the USP Rider to apply on a fully negotiated basis for certain Rate XD
13 customers to contribute to Rider USP and otherwise lower USP costs borne by the
14 Company’s residential customers.
- 15 • Rule 22 - References to outdated Effective Date in heading removed.
- 16 • Rate LFD has clarifying language added for Annual Minimum Bill, which allows
17 the Company and customer to reach agreement on a higher Annual Minimum Bill
18 amount. Updated residential and commercial purchase of receivables rates due to
19 the change in the MFC.

20

21 **Q. Does this conclude your direct testimony?**

22 A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

Work Experience

UGI Utilities, Inc., Denver, PA

November 2019 – Present Senior Manager, Tariff & Supplier Administration

2018 – November 2019 Manager, Revenue/Sales & Choice Administration

UGI Utilities, Inc., Reading, PA

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

Education

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

Previous testimony provided before the Pennsylvania Public Utility Commission:

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

Docket No. R-2024-3052716 UGI Gas Division Base Rate Case

UGI GAS

EXHIBIT SAE-2

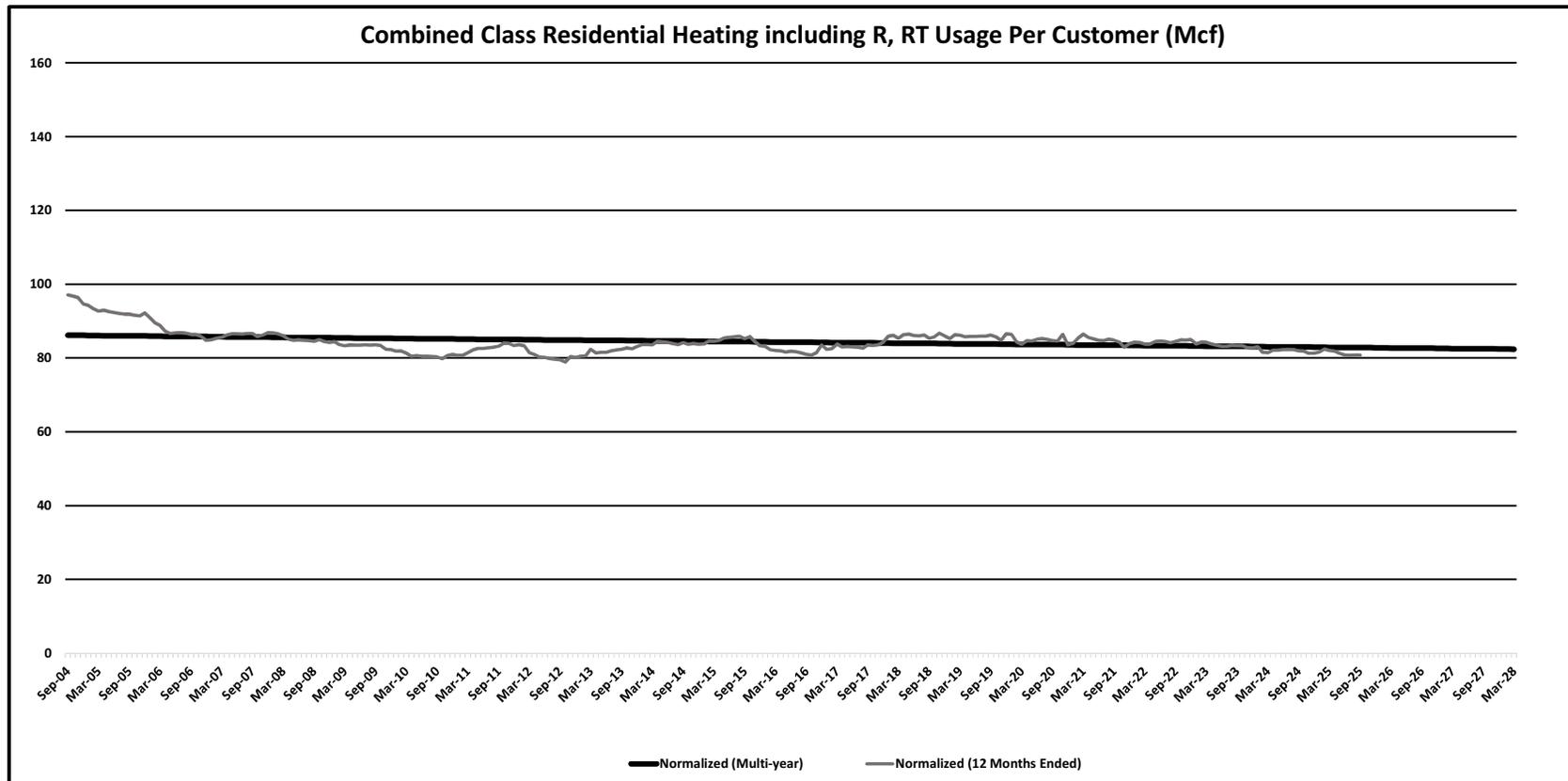
UGI Utilities, Inc. - Gas Division
10 Year Normal Heating Degree Days (2015-2024)

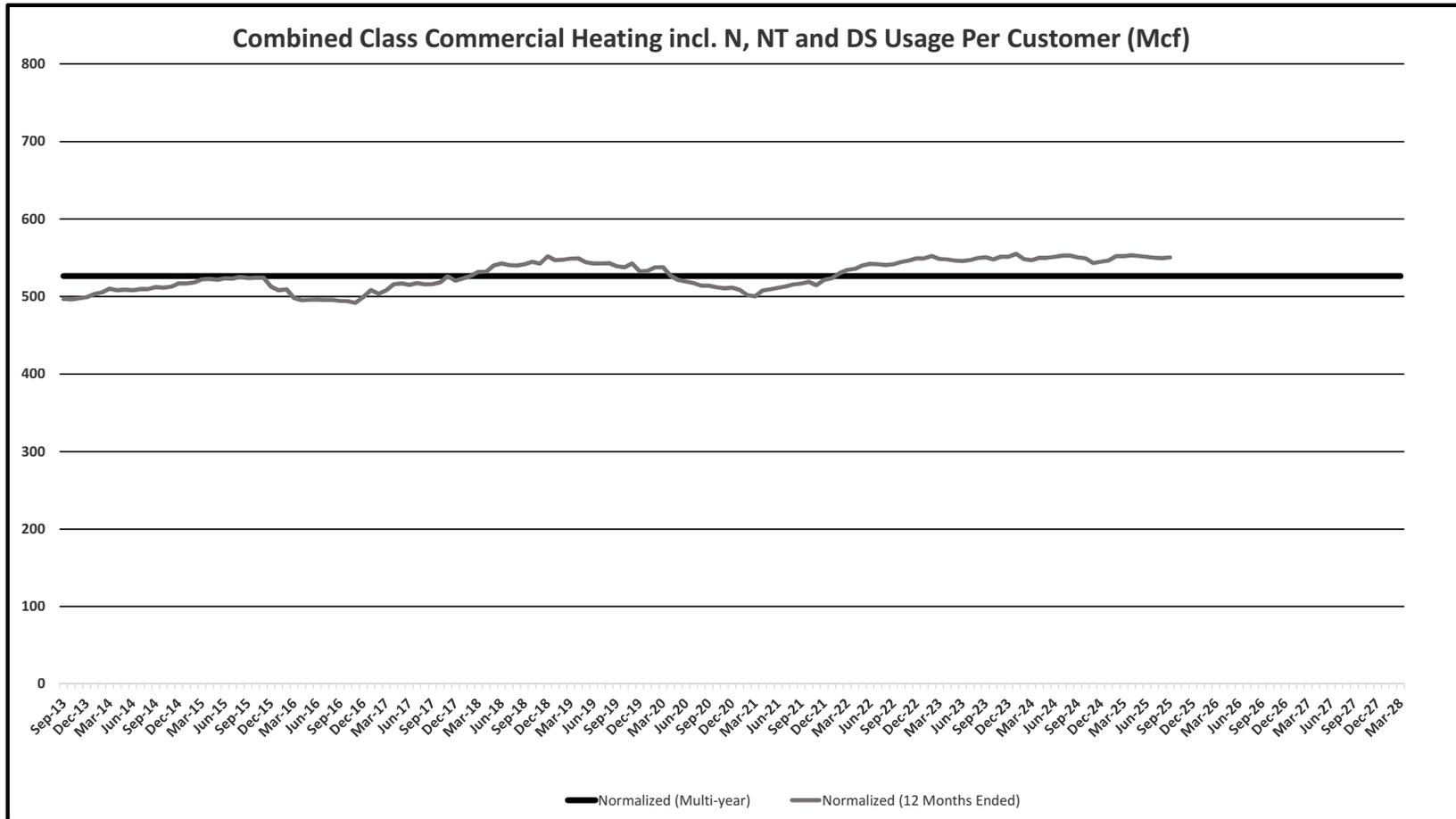
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Average *
Jan	1,247	1,139	966	1,159	1,153	932	1,030	1,231	829	994	1,069
Feb	1,292	923	722	776	908	799	978	876	753	782	881
Mar	974	586	878	912	834	607	658	684	745	611	749
Apr	420	475	270	579	329	504	397	459	320	349	410
May	93	227	214	67	126	234	214	102	175	101	155
Jun	38	27	38	32	30	21	21	17	34	12	27
Jul	8	4	3	4	2	0	6	1	1	1	0
Aug	13	4	23	3	9	4	3	4	6	15	8
Sep	51	57	94	63	39	101	63	90	79	39	68
Oct	392	326	237	373	275	317	190	386	299	287	309
Nov	525	595	694	780	773	514	728	593	685	569	647
Dec	640	982	1,096	891	928	946	765	970	760	963	895
Totals	5,692	5,345	5,236	5,639	5,406	4,980	5,050	5,411	4,685	4,724	5,218

*Average adjusted for rounding of 10 year calculation and normal representation of Heating Degree Days falling consecutively through normal year

UGI GAS

EXHIBIT SAE-3(a) – (b)





UGI GAS

EXHIBIT SAE-4(a) – (m)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2027 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues (\$000's)	Margin (\$000's) Reference
Budget 2027	343,586	1,270,313	795,899
Adjustment for Customer/Contract Changes	(834)	(11,756)	(5,856) UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(3,308)	(37,090)	(16,560) UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		1,938	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		39	39 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		(480)	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(257)	(257) 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		116	116 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Rider		(1)	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for EEC Conservation Impact	(240)	(3,000)	(1,467) UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for GDE		(185)	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Adjustment for DSIC		2,615	2,615 UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(m)
Fully Projected Future Test Year 2027	339,204	1,220,551	772,828

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
(\$ 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)	\$ 8,302	\$ 744,900	\$ 62,495	\$ 10,191	\$ 204,625	\$ 9,584	\$ 71,572	\$ 36,322	\$ 122,323	\$ 1,270,313
2	FPFTY PGC Revenues	\$ (2,392)	\$ (341,620)	\$ (5,371)	\$ (5,349)	\$ (111,591)	\$ (5,636)	\$ (521)	\$ (836)	\$ (1,096)	\$ (474,414)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	\$ 5,909	\$ 403,280	\$ 57,123	\$ 4,842	\$ 93,034	\$ 3,947	\$ 71,051	\$ 35,486	\$ 121,226	\$ 795,899
4	FPFTY Average Effective Customers (Unadjusted)	19,610	537,257	81,742	3,100	46,767	627	20,567	1,305	985	711,960
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	\$ 0.301	\$ 0.751	\$ 0.699	\$ 1.562	\$ 1.989	\$ 6.296	\$ 3.455	\$ 27.192	\$ 123.073	\$ 1.118
6	FPFTY Customers (Fully Adjusted)	19,178	533,332	81,742	3,081	45,429	613	20,567	1,305	985	706,232
7	Change in Customers during FPFTY (L6 - L4)	(432)	(3,925)	-	(19)	(1,338)	(14)	-	-	-	(5,728)
8	Annualization of Margin (L5 * L7)	\$ (130)	\$ (2,946)	\$ -	\$ (30)	\$ (2,662)	\$ (88)	\$ -	\$ -	\$ -	\$ (5,856)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	\$ 0.423	\$ 1.386	\$ 0.765	\$ 3.287	\$ 4.375	\$ 15.285	\$ 3.480	\$ 27.833	\$ 124.186	\$ 1.784
10	Annualization of Total FPFTY Revenue (L7 * L9)	\$ (183)	\$ (5,442)	\$ -	\$ (62)	\$ (5,854)	\$ (214)	\$ -	\$ -	\$ -	\$ (11,756)
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	\$ (53)	\$ (2,496)	\$ -	\$ (33)	\$ (3,193)	\$ (126)	\$ -	\$ -	\$ -	\$ (5,900)
12	Total FPFTY UPC (Unadjusted) - MCF	16.20	84.60	79.60	255.40	352.50	1,330.60	701.70	6,795.40		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(7)	(332)	-	(5)	(472)	(19)	-	-	-	(834)

Notes:

* 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, 2027
(\$ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1]	[2]	[3]	[4]	[5]
		LFD	XD-F	XD-I	IS	TOTAL
1	FPFTY Revenues (Unadjusted)	\$ 60,378	\$ 39,075	\$ 2,294	\$ 20,576	\$ 122,323
2	FPFTY PGC Revenues	(1,096)	-	-	-	(1,096)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	\$ 59,282	\$ 39,075	\$ 2,294	\$ 20,576	\$ 121,226
4	FPFTY Average Effective Customers (Unadjusted)	638	54	57	236	985
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	\$ 92.918	\$ 723.603	\$ 40.253	\$ 87.186	\$ 123.073
6	FPFTY Customers (Fully Adjusted)	638	54	57	236	985
7	Change in Customers during FPFTY (L6 - L4)	-	-	-	-	-
8	Annualization of Margin	\$ -	\$ -	\$ -	\$ -	\$ -
9	Average Annual Revenue Per Customer (L1 / L4)	\$ 94.637	\$ 723.603	\$ 40.253	\$ 87.186	\$ 124.186
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, 2027
(\$ 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	16.20	84.60	79.60	255.40	352.50	1,330.60	701.70	6,795.40			
2	FPFTY UPC (Fully Adjusted) - MCF	15.90	82.70	76.50	238.90	322.40	655.60	691.80	6,795.40			
3	Change in UPC - MCF (L2 - L1)	(0.30)	(1.90)	(3.10)	(16.50)	(30.10)	(675.00)	(9.90)	0.00			
4	FPFTY Customers (Fully Adjusted)	19,178	533,332	81,742	3,081	45,429	613	20,567	1,305	985	-	706,232
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000	(6)	(1,013)	(253)	(51)	(1,367)	(414)	(204)	-	-	-	(3,308)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	\$ (81)	\$ (14,271)	\$ (1,815)	\$ (565)	\$ (15,196)	\$ (4,598)	\$ (881)	\$ -	\$ -	\$ 317	\$ (37,090)
7	Total Unit Revenue Adjustment (L6 / L5)	\$ 14.0834	\$ 14.0834	\$ 7.1620	\$ 11.1127	\$ 11.1127	\$ 11.1127	\$ 4.3263	\$ -	\$ -	\$ -	\$ -
8	Distribution Margin Adjustment (L5 * L9)	\$ (36)	\$ (6,416)	\$ (1,604)	\$ (219)	\$ (5,880)	\$ (1,779)	\$ (876)	\$ -	\$ -	\$ -	\$ (16,811)
9	Distribution Unit Rate	\$ 6.3317	\$ 6.3317	\$ 6.3317	\$ 4.3004	\$ 4.3004	\$ 4.3004	\$ 4.3004	\$ 3.3651	\$ -	\$ -	\$ -
10	PGC Revenue (L5 * L11)	\$ (39)	\$ (6,839)	\$ -	\$ (343)	\$ (9,228)	\$ (2,792)	\$ -	\$ -	\$ -	\$ (179)	\$ (19,420)
11	PGC Unit Rate	\$ 6.7486	\$ 6.7486	\$ -	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ -	\$ -	\$ -	\$ -	\$ -
12	EE&C Revenue Adjustment (L5 * L13)	\$ (1)	\$ (197)	\$ (49)	\$ (1)	\$ (35)	\$ (11)	\$ (5)	\$ -	\$ -	\$ -	\$ (300)
13	EE&C Unit Rate	\$ 0.1940	\$ 0.1940	\$ 0.1940	\$ 0.0259	\$ 0.0259	\$ 0.0259	\$ 0.0259	\$ 0.0449	\$ -	\$ -	\$ -
14	USP Revenue Adjustment (L5 * L15)	\$ (4)	\$ (645)	\$ (161)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (810)
15	USP Unit Rate	\$ 0.6363	\$ 0.6363	\$ 0.6363	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	MFC Revenue/Margin Adjustment (L5 * L17)	\$ (1)	\$ (175)	\$ -	\$ (2)	\$ (52)	\$ (16)	\$ -	\$ -	\$ -	\$ -	\$ (245)
17	MFC Unit Rate	\$ 0.1728	\$ 0.1728	\$ -	\$ 0.0378	\$ 0.0378	\$ 0.0378	\$ -	\$ -	\$ -	\$ -	\$ -
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
19	DSIC Unit Rate	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
20	Total Margin Adjustment (L8 + L16 + L18)	\$ (37)	\$ (6,591)	\$ (1,604)	\$ (221)	\$ (5,932)	\$ (1,795)	\$ (876)	\$ -	\$ -	\$ 496	\$ (16,560)
21	Total Unit Margin Adjustment (L20 / L5)	\$ 6.5045	\$ 6.5045	\$ 6.3317	\$ 4.3382	\$ 4.3382	\$ 4.3382	\$ 4.3004	\$ -	\$ -	\$ -	\$ -

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, 2027
 (\$ in Thousands)

Adjustment for PGC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget PGC Rate FPFTY	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	
FPFTY PGC Rate	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	
PGC Rate Variance	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	
Total PGC Volumes	2,933	6,712	10,282	12,384	10,578	9,251	4,534	2,318	1,512	1,069	1,136	1,235	63,945
PGC Revenue Adjustment	\$89	\$203	\$312	\$375	\$321	\$280	\$137	\$70	\$46	\$32	\$34	\$37	\$1,938

UGI Utilities Inc. - Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
(\$ in Thousands)

Adjustment for MFC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget PGC Rate FPFTY	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	
FPFTY PGC Rate	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	
PGC Rate Variance	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	
Total PGC Volumes-Rate R	2,133	4,910	7,406	8,816	7,519	6,622	3,285	1,684	1,101	727	761	834	
Total PGC Volumes-Rate N	801	1,801	2,876	3,568	3,060	2,629	1,249	635	411	342	375	401	
Total PGC Volumes	2,933	6,712	10,282	12,384	10,578	9,251	4,534	2,318	1,512	1,069	1,136	1,235	63,945
Rate R %	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	
Rate N %	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	
MFC Rate R 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	
MFC Rate N Adj Rate	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	
Rate R Revenue Variance	\$2	\$4	\$6	\$7	\$6	\$5	\$3	\$1	\$1	\$1	\$1	\$1	
Rate N Revenue Variance	\$0	\$0	\$0	\$1	\$1	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
Total Revenue Variance	\$2	\$4	\$6	\$7	\$6	\$6	\$3	\$1	\$1	\$1	\$1	\$1	\$39

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
(\$ in Thousands)

Adjustment for USP

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original FPFTY Budget USP Calculation	\$1,503	\$3,460	\$5,226	\$6,209	\$5,291	\$4,649	\$2,303	\$1,182	\$779	\$516	\$538	\$591	\$32,247
Updated FPFTY Budget USP Calculation	\$1,501	\$3,455	\$5,219	\$6,200	\$5,284	\$4,642	\$2,299	\$1,180	\$778	\$515	\$537	\$590	\$32,202
Variance to Original FPFTY Budget Calculation	(\$2)	(\$5)	(\$7)	(\$9)	(\$7)	(\$7)	(\$3)	(\$2)	(\$1)	(\$1)	(\$1)	(\$1)	(\$46)
Original FPFTY Budget USP Rate	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	\$0.6450	
FPFTY USP Rate	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	
USP Rate Variance	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	(\$0.0087)	
Total Rate R Volumes	2,438	5,612	8,476	10,070	8,582	7,541	3,735	1,918	1,263	837	872	959	52,302
Total Rate R excl CAP Volumes	2,327	5,357	8,091	9,613	8,192	7,197	3,565	1,830	1,205	799	833	915	49,925
USP Rate Revenue Variance	(\$20)	(\$47)	(\$70)	(\$84)	(\$71)	(\$63)	(\$31)	(\$16)	(\$10)	(\$7)	(\$7)	(\$8)	(\$434)
Total Revenue Variance	(\$22)	(\$52)	(\$78)	(\$92)	(\$79)	(\$69)	(\$34)	(\$18)	(\$12)	(\$8)	(\$8)	(\$9)	(\$480)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
(\$ in Thousands)

Adjustment for GPC

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	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	(171)	(396)	(619)	(762)	(652)	(563)	(271)	(136)	(87)	(68)	(75)	(88)	(3,888)
Revenue Variance	(\$11)	(\$26)	(\$41)	(\$50)	(\$43)	(\$37)	(\$18)	(\$9)	(\$6)	(\$4)	(\$5)	(\$6)	(\$257)

UGI Utilities Inc. - Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
(\$ 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, 2027
(\$ in Thousands)

Adjustment for STAS

	@ 0%	@.01%	Revenue
	Unadjusted	Adjusted	Adjustment
	2027	2027	Total
	TOTAL	TOTAL	Total
Residential-Non Htg	\$ -	\$ 1	\$ 1
Residential-Heating	\$ -	\$ 73	\$ 73
Residential-RT	\$ -	\$ 6	\$ 6
Total R/RT	\$ -	\$ 79	\$ 79
Commercial-Non Htg	\$ -	\$ 1	\$ 1
Commercial- Htg	\$ -	\$ 18	\$ 18
Industrial	\$ -	\$ 0	\$ 0
Com/Ind NT	\$ -	\$ 7	\$ 7
Total N/NT	\$ -	\$ 27	\$ 27
Total DS	\$ -	\$ 4	\$ 4
Total LFD	\$ -	\$ 6	\$ 6
Total XD-F	\$ -	\$ -	\$ -
Total Interruptible	\$ -	\$ -	\$ -
Grand Total	\$ -	\$ 116	\$ 116

UGI Utilities Inc. - Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
(\$ in Thousands)

Adjustment for EEC Rider

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget 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	
FPFTY R/RT Rate	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	
R/RT Rate Variance	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	
R/RT Rate Volumes	2,438	5,612	8,476	10,070	8,582	7,541	3,735	1,918	1,263	837	872	959	52,302
R/RT Revenue Adjustment	\$32	\$74	\$112	\$133	\$113	\$100	\$49	\$25	\$17	\$11	\$12	\$13	\$690
Original Budget 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	
FPFTY N/NT Rate	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	
N/NT Rate Variance	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	
N/NT Rate Volumes	1,588	3,234	4,997	6,090	5,240	4,514	2,291	1,257	938	760	815	855	32,580
N/NT Revenue Adjustment	(\$16)	(\$33)	(\$51)	(\$62)	(\$53)	(\$46)	(\$23)	(\$13)	(\$10)	(\$8)	(\$8)	(\$9)	(\$332)
Original Budget 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	
FPFTY DS Rate	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	
DS Rate Variance	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	
DS Rate Volumes	469	791	1,231	1,588	1,421	1,179	683	413	291	248	254	301	8,868
DS Revenue Adjustment	(\$21)	(\$35)	(\$54)	(\$70)	(\$62)	(\$52)	(\$30)	(\$18)	(\$13)	(\$11)	(\$11)	(\$13)	(\$389)
Original Budget 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	
FPFTY LFD Rate	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	
LFD Rate Variance	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	
LFD Rate Volumes	2,178	2,440	2,722	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,342
LFD Revenue Adjustment	\$2	\$3	\$3	\$3	\$3	\$3	\$2	\$2	\$2	\$2	\$2	\$2	\$30
Total Revenue Adjustment	(\$2)	\$9	\$10	\$4	\$0	\$5	(\$2)	(\$3)	(\$4)	(\$6)	(\$6)	(\$7)	(\$1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2027
 (\$ 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 5 Year Average	MMBTU BTU	MCF 5 Year Average	Customers FY27 Retail Htg & Choice Htg	EE&C UPC Conservation Adj	
										2026
Residential (R/RT)	187,035	198,006	206,266	214,128	223,043	205,696	1,033	199,124	611,318	(0.3)
Nonresidential (N/NT)	35,354	38,780	41,988	46,016	48,158	42,059	1,033	40,716	65,129	(0.6)
Total	222,389	236,786	248,254	260,144	271,201	247,755		239,840	676,447	

Description	[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Rate R Residential-Htg	Rate RT Residential Htg-RT	Rate N Commercial-Htg	Rate NT Commercial Htg-NT	Rate N Industrial	Rate NT Industrial -NT	Total
FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	82.7	79.4	322.4	674.9	655.6	2,053.9	
FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	82.4	79.1	321.8	674.3	655.0	2,053.3	
Change in UPC -MCF	(0.3)	(0.3)	(0.6)	(0.6)	(0.6)	(0.6)	
End of Year FPFTY Customers	533,332	77,986	45,429	18,631	613	456	676,447
Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(174)	(25)	(28)	(12)	(0)	(0)	(240)
Total Revenue Adjustment (L10 + L12 + L14 + L22)	\$ (2,447)	\$ (182)	\$ (316)	\$ (50)	\$ (4)	\$ (1)	\$ (3,000)
Total Unit Revenue Adjustment (L6 / L5)	14.0834	7.1620	11.1127	4.3263	11.1127	4.3263	12.5084
Distribution Margin Adjustment (L5 * L9)	\$ (1,100)	\$ (161)	\$ (122)	\$ (50)	\$ (2)	\$ (1)	\$ (1,436)
Distribution Unit Rate	\$ 6.3317	\$ 6.3317	\$ 4.3004	\$ 4.3004	\$ 4.3004	\$ 4.3004	
PGC Revenue (L5 * L11)	\$ (1,172)	\$ -	\$ (192)	\$ -	\$ (3)	\$ -	\$ (1,367)
PGC Unit Rate	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ 6.7486	
EE&C Revenue Adjustment (L5 * L13)	\$ (34)	\$ (5)	\$ (1)	\$ (0)	\$ (0)	\$ (0)	\$ (40)
EE&C Unit Rate	\$ 0.1940	\$ 0.1940	\$ 0.0259	\$ 0.0259	\$ 0.0259	\$ 0.0259	
USP Revenue Adjustment (L5 * L15)	\$ (111)	\$ (16)					\$ (127)
USP Unit Rate	\$ 0.6363	\$ 0.6363					
MFC Revenue/Margin Adjustment (L5 * L17)	\$ (30)	\$ -	\$ (1)	\$ -	\$ (0)	\$ -	\$ (31)
MFC Unit Rate	\$ 0.1728	\$ 0.1728	\$ 0.0378	\$ 0.0378	\$ 0.0378	\$ 0.0378	
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
DSIC Unit Rate	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Total Margin Adjustment (L8 + L16 + L18)	\$ (1,130)	\$ (161)	\$ (123)	\$ (50)	\$ (2)	\$ (1)	\$ (1,467)
Total Unit Margin Adjustment (L20 / L5)	\$ 6.5045	\$ 6.3317	\$ 4.3382	\$ 4.3004	\$ 4.3382	\$ 4.3004	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2027
(\$ in Thousands)

Adjustment for GDE Rider

	OCT 2026	NOV 2026	DEC 2026	JAN 2027	FEB 2027	MAR 2027	APR 2027	MAY 2027	JUN 2027	JUL 2027	AUG 2027	SEP 2027	TOTAL
Original Budget FPFTY 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	
FPFTY DS Rate	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	
DS Rate Variance	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	
DS Rate Volumes	469	791	1,231	1,588	1,421	1,179	683	413	291	248	254	301	8,868
DS Revenue Adjustment	(\$2)	(\$4)	(\$6)	(\$8)	(\$7)	(\$6)	(\$3)	(\$2)	(\$1)	(\$1)	(\$1)	(\$2)	(\$45)
Original Budget FPFTY 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	
FPFTY LFD Rate	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	
LFD Rate Variance	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	
LFD Rate Volumes	2,178	2,440	2,722	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,342
LFD Revenue Adjustment	(\$11)	(\$12)	(\$14)	(\$15)	(\$13)	(\$13)	(\$11)	(\$10)	(\$10)	(\$10)	(\$10)	(\$10)	(\$139)
Total Revenue Adjustment	(\$14)	(\$16)	(\$20)	(\$23)	(\$21)	(\$19)	(\$15)	(\$13)	(\$11)	(\$11)	(\$11)	(\$11)	(\$185)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year- 12 Months Ended September 30, 2027
(\$ in Thousands)

Adjustment for DSIC

	@ 0%	@0.33%		
	Unadjusted	Adjusted	Revenue	
	2027	2027	Adjustment	
	TOTAL	TOTAL	Total	
Residential-Non Htg	\$ -	\$ 20	\$ 20	
Residential-Heating	\$ -	\$ 1,412	\$ 1,412	
Residential-RT	\$ -	\$ 199	\$ 199	
Total R/RT	\$ -	\$ 1,631	\$ 1,631	
Commercial-Non Htg	\$ -	\$ 15	\$ 15	
Commercial- Htg	\$ -	\$ 280	\$ 280	
Industrial	\$ -	\$ 7	\$ 7	
Com/Ind NT	\$ -	\$ 233	\$ 233	
Total N/NT	\$ -	\$ 534	\$ 534	
Total DS	\$ -	\$ 118	\$ 118	
Total LFD	\$ -	\$ 193	\$ 193	
Total XD-F	\$ -	\$ 64	\$ 64	
Total Interruptible	\$ -	\$ 73	\$ 73	
Grand Total	\$ -	\$ 2,615	\$ 2,615	

UGI GAS

EXHIBIT SAE-5(a) – (I)

UGI Utilities Inc.- Gas Division
 Future Test Year 2026 Sales and Revenues
 Summary of Adjustments

	Sales (000's) MCF	Revenues (\$000's)	Margin (\$000's) Reference
Budget 2026	343,090	1,256,178	787,256
Adjustment for Customer/Contract Changes	(981)	(11,976)	(5,772) UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(3,141)	(35,047)	(15,964) UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		2,994	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		60	60 UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		480	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(235)	(235) 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		205	205 UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for EEC Rider		(7)	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for GDE		(184)	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(k)
Adjustment for DSIC		(338)	(338) UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(l)
Future Test Year 2026	338,968	1,210,430	763,512

UGI Utilities Inc.- Gas Division
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	FTY Revenues (Unadjusted)	\$ 8,535	\$ 733,593	\$ 62,205	\$ 10,210	\$ 203,505	\$ 9,705	\$ 71,281	\$ 35,926	\$ 121,219	\$ 1,256,178
2	FTY PGC Revenues	\$ (2,462)	\$ (336,525)	\$ (5,310)	\$ (5,371)	\$ (111,100)	\$ (5,704)	\$ (521)	\$ (834)	\$ (1,095)	\$ (468,922)
3	FTY Revenues net of PGC - Margin (Unadjusted)	\$ 6,073	\$ 397,068	\$ 56,895	\$ 4,840	\$ 92,405	\$ 4,000	\$ 70,760	\$ 35,092	\$ 120,124	\$ 787,256
4	FTY Average Effective Customers (Unadjusted)	20,245	531,109	81,742	3,121	46,668	637	20,567	1,304	984	706,377
5	FTY Average Annual Margin Per Customer (L3 / L4)	\$ 0.300	\$ 0.748	\$ 0.696	\$ 1.551	\$ 1.980	\$ 6.280	\$ 3.440	\$ 26.911	\$ 122.077	\$ 1.114
6	FTY Customers (Fully Adjusted)	19,789	527,108	81,742	3,103	45,208	625	20,567	1,304	984	700,430
7	Change in Customers during FTY (L6 - L4)	(456)	(4,001)	-	(18)	(1,460)	(12)	-	-	-	(5,947)
8	Annualization of Margin (L5 * L7)	\$ (137)	\$ (2,991)	\$ -	\$ (28)	\$ (2,891)	\$ (75)	\$ -	\$ -	\$ 351	\$ (5,772)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	\$ 0.422	\$ 1.381	\$ 0.761	\$ 3.272	\$ 4.361	\$ 15.235	\$ 3.466	\$ 27.551	\$ 123.190	\$ 1.778
10	Annualization of Total FTY Revenue (L7 * L9)	\$ (192)	\$ (5,526)	\$ -	\$ (59)	\$ (6,367)	\$ (183)	\$ -	\$ -	\$ 351	\$ (11,976)
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	\$ (55)	\$ (2,535)	\$ -	\$ (31)	\$ (3,476)	\$ (107)	\$ -	\$ -	\$ -	\$ (6,205)
12	Total FTY UPC (Unadjusted) - MCF	16.20	84.60	79.60	255.40	352.50	1,327.80	701.70	6,783.40		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(7)	(338)	-	(5)	(515)	(16)	-	-	(99)	(981)

Notes:

* 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, 2026
(\$ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1]	[2]	[3]	[4]	[5]
		LFD	XD-F	XD-I	IS	TOTAL
1	FTY Revenues (Unadjusted)	\$ 60,462	\$ 38,765	\$ 2,276	\$ 19,716	\$ 121,219
2	FTY PGC Revenues	(1,095)	-	-	-	(1,095)
3	FTY Revenues net of PGC - Margin (Unadjusted)	\$ 59,367	\$ 38,765	\$ 2,276	\$ 19,716	\$ 120,124
4	FTY Average Effective Customers (Unadjusted)	637	55	58	234	984
5	FTY Average Annual Margin Per Customer (L3 / L4)	\$ 93.197	\$ 704.820	\$ 39.233	\$ 84.258	\$ 122.077
6	FTY Customers (Fully Adjusted)	638	54	57	235	984
7	Change in Customers during FTY (L6 - L4)	1	(1)	(1)	1	-
8	Annualization of Margin	\$ 37	\$ (177)	\$ -	\$ 491	\$ 351
9	Average Annual Revenue Per Customer (L1 / L4)	\$ 94.917	\$ 704.820	\$ 39.233	\$ 84.258	\$ 123.190
10	Annualization of Total FTY Revenue	\$ 37	\$ (177)	\$ -	\$ 491	\$ 351
11	Annualization of FTY PGC Revenues (L10 - L8)	\$ -	\$ -	\$ -	\$ -	\$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	21	(366)	-	245	(99)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2026
(\$ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Rate R Residential-Non Htg	Rate R Residential-Htg	Rate RT RT	Rate N Commercial-Non Htg	Rate N Commercial-Htg	Rate N Industrial	Rate NT NT Total	Rate DS DS Total	Rates LFD, XD, IS Transport-Other	Total
1	FTY (Unadjusted) Use/Customer ("UPC") - MCF	16.20	84.60	79.60	255.40	352.50	1,327.80	701.70	6,783.40		
2	FTY UPC (Fully Adjusted) - MCF	15.90	83.00	76.50	239.80	321.40	719.10	691.80	6,783.40		
3	Change in UPC - MCF (L2 - L1)	(0.30)	(1.60)	(3.10)	(15.60)	(31.10)	(608.70)	(9.90)	0.00		
4	FTY Customers (Fully Adjusted)	19,789	527,108	81,742	3,103	45,208	625	20,567	1,304	984	700,430
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	(6)	(843)	(253)	(48)	(1,406)	(380)	(204)	-	-	(3,141)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	\$ (84)	\$ (11,878)	\$ (1,815)	\$ (538)	\$ (15,624)	\$ (4,228)	\$ (881)	\$ -	\$ -	\$ (35,047)
7	Total Unit Revenue Adjustment (L6 / L5)	\$ 14.0834	\$ 14.0834	\$ 7.1620	\$ 11.1127	\$ 11.1127	\$ 11.1127	\$ 4.3263	\$ -	\$ -	
8	Distribution Margin Adjustment (L5 * L9)	\$ (38)	\$ (5,340)	\$ (1,604)	\$ (208)	\$ (6,046)	\$ (1,636)	\$ (876)	\$ -	\$ -	\$ (15,748)
9	Distribution Unit Rate	\$ 6.3317	\$ 6.3317	\$ 6.3317	\$ 4.3004	\$ 4.3004	\$ 4.3004	\$ 4.3004	\$ 3.3651	\$ -	
10	PGC Revenue (L5 * L11)	\$ (40)	\$ (5,692)	\$ -	\$ (327)	\$ (9,488)	\$ (2,567)	\$ -	\$ -	\$ -	\$ (18,114)
11	PGC Unit Rate	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ 6.7486	\$ 6.7486				
12	EE&C Revenue Adjustment (L5 * L13)	\$ (1)	\$ (164)	\$ (49)	\$ (1)	\$ (36)	\$ (10)	\$ (5)	\$ -	\$ -	\$ (267)
13	EE&C Unit Rate	\$ 0.1940	\$ 0.1940	\$ 0.1940	\$ 0.0259	\$ 0.0259	\$ 0.0259	\$ 0.0259	\$ 0.0449	\$ -	
14	USP Revenue Adjustment (L5 * L15)	\$ (4)	\$ (537)	\$ (161)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (702)
15	USP Unit Rate	\$ 0.6363	\$ 0.6363	\$ 0.6363	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
16	MFC Revenue/Margin Adjustment (L5 * L17)	\$ (1)	\$ (146)	\$ -	\$ (2)	\$ (53)	\$ (14)				\$ (216)
17	MFC Unit Rate	\$ 0.1728	\$ 0.1728	\$ 0.1728	\$ 0.0378	\$ 0.0378	\$ 0.0378				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
19	DSIC Unit Rate	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
20	Total Margin Adjustment (L8 + L16 + L18)	\$ (39)	\$ (5,486)	\$ (1,604)	\$ (210)	\$ (6,099)	\$ (1,650)	\$ (876)	\$ -	\$ -	\$ (15,964)
21	Total Unit Margin Adjustment (L20 / L5)	\$ 6.5045	\$ 6.5045	\$ 6.3317	\$ 4.3382	\$ 4.3382	\$ 4.3382	\$ 4.3004	\$ -	\$ -	

**UGI Utilities Inc.- Gas Division
 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 FTY	\$6.6061	\$6.6061	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	
FTY PGC Rate	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	
PGC Rate Variance	\$0.1425	\$0.1425	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	
Total PGC Volumes	2,907	6,654	10,197	12,284	10,493	9,175	4,496	2,299	1,499	1,061	1,127	1,225	63,417
PGC Revenue Adjustment	\$414	\$948	\$309	\$372	\$318	\$278	\$136	\$70	\$45	\$32	\$34	\$37	\$2,994

**UGI Utilities Inc. - Gas Division
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 FTY	\$6.6061	\$6.6061	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	\$6.7183	
FTY PGC Rate	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	\$6.7486	
PGC Rate Variance	\$0.1425	\$0.1425	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	\$0.0303	
Total PGC Volumes-Rate R	2,109	4,855	7,323	8,718	7,435	6,548	3,248	1,665	1,089	719	752	824	
Total PGC Volumes-Rate N	799	1,799	2,874	3,566	3,058	2,627	1,248	634	410	341	374	401	
Total PGC Volumes	2,907	6,654	10,197	12,284	10,493	9,175	4,496	2,299	1,499	1,061	1,127	1,225	63,417
Rate R %	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	2.56%	
Rate N %	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	
MFC Rate R Adj Rate	\$0.0036	\$0.0036	\$0.0008	\$0.0008	\$0.0008	\$0.0008	\$0.0008	\$0.0008	\$0.0008	\$0.0008	\$0.0008	\$0.0008	
MFC Rate N Adj Rate	\$0.0008	\$0.0008	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	\$0.0002	
Rate R Revenue Variance	\$8	\$18	\$6	\$7	\$6	\$5	\$3	\$1	\$1	\$1	\$1	\$1	
Rate N Revenue Variance	\$1	\$1	\$0	\$1	\$1	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
Total Revenue Variance	\$8	\$19	\$6	\$7	\$6	\$6	\$3	\$1	\$1	\$1	\$1	\$1	\$60

UGI Utilities Inc.- Gas Division
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 FTY Budget USP Calculation	\$1,444	\$3,324	\$5,020	\$6,103	\$5,201	\$4,569	\$2,263	\$1,162	\$766	\$507	\$529	\$581	\$31,469
Updated FTY Budget USP Calculation	\$1,442	\$3,319	\$5,013	\$6,094	\$5,194	\$4,563	\$2,260	\$1,160	\$765	\$507	\$528	\$580	\$31,425
Variance to Original FTY Budget Calculation	(\$2)	(\$5)	(\$7)	(\$9)	(\$7)	(\$6)	(\$3)	(\$2)	(\$1)	(\$1)	(\$1)	(\$1)	(\$44)
Original FTY Budget USP Rate	\$0.6257	\$0.6257	\$0.6257	\$0.6402	\$0.6402	\$0.6402	\$0.6402	\$0.6402	\$0.6402	\$0.6402	\$0.6402	\$0.6402	
FTY USP Rate	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	\$0.6363	
USP Rate Variance	\$0.0106	\$0.0106	\$0.0106	(\$0.0039)	(\$0.0039)	(\$0.0039)	(\$0.0039)	(\$0.0039)	(\$0.0039)	(\$0.0039)	(\$0.0039)	(\$0.0039)	
Total Rate R Volumes	2,413	5,556	8,392	9,972	8,499	7,467	3,699	1,899	1,251	829	864	949	51,790
Total Rate R excl CAP Volumes	2,304	5,304	8,012	9,520	8,113	7,127	3,530	1,813	1,194	791	825	907	49,440
USP Rate Revenue Variance	\$24	\$56	\$85	\$101	\$86	\$76	\$37	\$19	\$13	\$8	\$9	\$10	\$524
Total Revenue Variance	\$22	\$52	\$78	\$92	\$79	\$69	\$34	\$18	\$12	\$8	\$8	\$9	\$480

UGI Utilities Inc.- Gas Division
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 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	(156)	(361)	(568)	(700)	(599)	(517)	(248)	(125)	(80)	(62)	(69)	(81)	(3,565)
Revenue Variance	(\$10)	(\$24)	(\$37)	(\$46)	(\$40)	(\$34)	(\$16)	(\$8)	(\$5)	(\$4)	(\$5)	(\$5)	(\$235)

UGI Utilities Inc.- Gas Division
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
Future Test Year- 12 Months Ended September 30, 2026
(\$ in Thousands)

Adjustment for STAS

	@ 0.01%			
	Unadjusted	Adjusted	Revenue	
	2026	2026	Adjustment	
	TOTAL	TOTAL	Total	
Residential-Non Htg	\$ (1)	\$ 1	\$ 2	
Residential-Heating	\$ (51)	\$ 73	\$ 124	
Residential-RT	\$ (5)	\$ 6	\$ 11	
Total R/RT	\$ (56)	\$ 80	\$ 136	
Commercial-Non Htg	\$ (1)	\$ 1	\$ 2	
Commercial- Htg	\$ (13)	\$ 20	\$ 33	
Industrial	\$ (0)	\$ 1	\$ 1	
Com/Ind NT	\$ (5)	\$ 7	\$ 13	
Total N/NT	\$ (20)	\$ 29	\$ 49	
Total DS	\$ (3)	\$ 4	\$ 7	
Total LFD	\$ (7)	\$ 6	\$ 13	
Total XD-F	\$ -	\$ -	\$ -	
Total Interruptible	\$ -	\$ -	\$ -	
Grand Total	\$ (86)	\$ 120	\$ 205	

**UGI Utilities Inc. - Gas Division
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 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	
FTY R/RT Rate	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	\$0.1940	
R/RT Rate Variance	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	\$0.0132	
R/RT Rate Volumes	2,413	5,556	8,392	9,972	8,499	7,467	3,699	1,899	1,251	829	864	949	51,790
R/RT Revenue Adjustment	\$32	\$73	\$111	\$132	\$112	\$99	\$49	\$25	\$17	\$11	\$11	\$13	\$684
Original Budget 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	
FTY N/NT Rate	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	\$0.0259	
N/NT Rate Variance	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	(\$0.0102)	
N/NT Rate Volumes	1,586	3,231	4,995	6,088	5,239	4,512	2,290	1,256	938	759	815	855	32,563
N/NT Revenue Adjustment	(\$16)	(\$33)	(\$51)	(\$62)	(\$53)	(\$46)	(\$23)	(\$13)	(\$10)	(\$8)	(\$8)	(\$9)	(\$332)
Original Budget 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	
FTY DS Rate	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	\$0.0449	
DS Rate Variance	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	(\$0.0439)	
DS Rate Volumes	467	788	1,227	1,583	1,416	1,177	682	413	291	248	254	301	8,845
DS Revenue Adjustment	(\$21)	(\$35)	(\$54)	(\$69)	(\$62)	(\$52)	(\$30)	(\$18)	(\$13)	(\$11)	(\$11)	(\$13)	(\$388)
Original Budget 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	
FTY LFD Rate	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	\$0.0357	
LFD Rate Variance	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	\$0.0011	
LFD Rate Volumes	2,167	2,428	2,719	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,315
LFD Revenue Adjustment	\$2	\$3	\$3	\$3	\$3	\$3	\$2	\$2	\$2	\$2	\$2	\$2	\$30
Total Revenue Adjustment	(\$2)	\$8	\$9	\$3	(\$1)	\$4	(\$2)	(\$4)	(\$4)	(\$6)	(\$6)	(\$7)	(\$7)

UGI Utilities Inc.- Gas Division
Future Test Year Period- 12 Months Ended September 30, 2026
(\$ in Thousands)

Adjustment for GDE 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 FTY 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	
FTY DS Rate	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	
DS Rate Variance	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	
DS Rate Volumes	467	788	1,227	1,583	1,416	1,177	682	413	291	248	254	301	8,845
DS Revenue Adjustment	(\$2)	(\$4)	(\$6)	(\$8)	(\$7)	(\$6)	(\$3)	(\$2)	(\$1)	(\$1)	(\$1)	(\$2)	(\$45)
Original Budget FTY 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	
FTY LFD Rate	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	\$0.0004	
LFD Rate Variance	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	(\$0.0051)	
LFD Rate Volumes	2,167	2,428	2,719	2,939	2,626	2,543	2,211	2,050	1,900	1,877	1,911	1,945	27,315
LFD Revenue Adjustment	(\$11)	(\$12)	(\$14)	(\$15)	(\$13)	(\$13)	(\$11)	(\$10)	(\$10)	(\$10)	(\$10)	(\$10)	(\$139)
Total Revenue Adjustment	(\$13)	(\$16)	(\$20)	(\$23)	(\$21)	(\$19)	(\$15)	(\$13)	(\$11)	(\$11)	(\$11)	(\$11)	(\$184)

**UGI Utilities Inc.- Gas Division
 Future Test Year- 12 Months Ended September 30, 2026
 (\$ in Thousands)**

Adjustment for DSIC

	Unadjusted 2026 TOTAL	@0.33% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	\$23	\$21	(\$3)
Residential-Heating	\$1,601	\$1,422	(\$179)
Residential-RT	\$230	\$205	(\$26)
Total R/RT	\$1,855	\$1,647	(\$208)
Commercial-Non Htg	\$18	\$16	(\$2)
Commercial- Htg	\$344	\$306	(\$39)
Industrial	\$15	\$13	(\$2)
Com/Ind NT	\$264	\$234	(\$30)
Total N/NT	\$641	\$569	(\$72)
Total DS	\$133	\$118	(\$15)
Total LFD	\$223	\$198	(\$25)
Total XD-F	\$84	\$74	(\$9)
Total Interruptible	\$79	\$70	(\$9)
Grand Total	\$3,015	\$2,677	(\$338)

UGI GAS

EXHIBIT SAE-6(a) – (k)

UGI Utilities Inc.- Gas Division
 Historic Test Year 2025 Sales and Revenues
 Summary of Adjustments

	Sales (000's) MCF	Revenues (\$000's)	Margin (\$000's) Reference
Actual 2025	321,629	1,137,255	718,427
Adjustment for Customer/Contract Changes	(1,938)	(10,270)	(5,921) UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(656)	(4,503)	(1,093) UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for WNA		(16,327)	(16,327) UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for PGC		51,422	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for MFC		907	907 UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for USP		7,370	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for GPC		(86)	(86) UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for Excess Take		(2,199)	(2,199) UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for STAS		43	43 UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for EEC Rider		16	0 UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(k)
Historic Test Year 2025	319,035	1,163,630	693,752

UGI Utilities Inc.- Gas Division
Historic 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	HTY Revenues net of WNA (Unadjusted)	\$ 8,165	\$ 619,588	\$ 53,943	\$ 8,618	\$ 170,650	\$ 7,954	\$ 65,540	\$ 50,460	\$ 136,011	\$ 1,120,928
2	HTY PGC Revenues	\$ (2,233)	\$ (279,839)	\$ (4,739)	\$ (4,442)	\$ (91,044)	\$ (4,543)	\$ (505)	\$ (16,078)	\$ (15,406)	\$ (418,829)
3	HTY Revenues net of PGC and WNA - Margin (Unadjusted)	\$ 5,932	\$ 339,749	\$ 49,204	\$ 4,175	\$ 79,606	\$ 3,411	\$ 65,035	\$ 34,382	\$ 120,605	\$ 702,099
4	HTY Average Effective Customers (Unadjusted)	21,010	525,925	81,167	3,136	45,320	676	20,780	1,301	978	700,293
5	HTY Average Annual Margin Per Customer (L3 / L4)	\$ 0.282	\$ 0.646	\$ 0.606	\$ 1.331	\$ 1.757	\$ 5.046	\$ 3.130	\$ 26.427	\$ 123.318	\$ 1.003
6	HTY Customers (Fully Adjusted)	20,477	519,287	82,349	3,105	44,978	673	20,620	1,295	975	693,759
7	Change in Customers during HTY (L6 - L4)	(533)	(6,638)	1,182	(31)	(342)	(3)	(160)	(6)	(3)	(6,534)
8	Annualization of Margin (L5 * L7)	\$ (150)	\$ (4,288)	\$ 717	\$ (41)	\$ (601)	\$ (15)	\$ (501)	\$ (159)	\$ (882)	\$ (5,921)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	\$ 0.389	\$ 1.178	\$ 0.665	\$ 2.748	\$ 3.765	\$ 11.767	\$ 3.154	\$ 38.786	\$ 139.071	\$ 1.601
10	Annualization of Total HTY Revenue (L7 * L9)	\$ (207)	\$ (7,820)	\$ 786	\$ (85)	\$ (1,288)	\$ (35)	\$ (505)	\$ (233)	\$ (882)	\$ (10,270)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	\$ (57)	\$ (3,532)	\$ 69	\$ (44)	\$ (687)	\$ (20)	\$ (4)	\$ (74)	\$ -	\$ (4,349)
12	Total HTY UPC (Unadjusted) - MCF	15.90	81.20	76.80	234.60	345.00	1,151.20	693.70	7,029.70		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(8)	(539)	91	(7)	(118)	(3)	(111)	(42)	(1,200)	(1,938)

Notes:
* 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, 2025
(\$ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1]	[2]	[3]	[4]	[5]
		LFD	XD-F	XD-I	IS	TOTAL
1	HTY Revenues (Unadjusted)	\$ 67,832	\$ 39,433	\$ 2,984	\$ 25,762	\$ 136,011
2	HTY PGC Revenues	(11,173)	(267)	(23)	(3,943)	(15,406)
3	HTY Revenues net of PGC - Margin (Unadjusted)	\$ 56,659	\$ 39,167	\$ 2,961	\$ 21,819	\$ 120,605
4	HTY Average Effective Customers (Unadjusted)	626	56	58	238	978
5	HTY Average Annual Margin Per Customer (L3 / L4)	\$ 90.510	\$ 699.407	\$ 51.051	\$ 91.675	\$ 123.318
6	HTY Customers (Fully Adjusted)	632	56	58	229	975
7	Change in Customers during HTY (L6 - L4)	6	-	-	(9)	(3)
8	Annualization of Margin	\$ 322	\$ -	\$ -	\$ (1,204)	\$ (882)
9	Average Annual Revenue Per Customer (L1 / L4)	\$ 108.358	\$ 704.168	\$ 51.441	\$ 108.243	\$ 139.071
10	Annualization of Total HTY Revenue	\$ 322	\$ -	\$ -	\$ (1,204)	\$ (882)
11	Annualization of HTY PGC Revenues (L10 - L8)	\$ -	\$ -	\$ -	\$ -	\$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for HTY Sales - MMCF	129	-	-	(1,329)	(1,200)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
(\$ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Rate R Residential-Non Htg	Rate R Residential-Htg	Rate RT RT	Rate N Commercial-Non Htg	Rate N Commercial-Htg	Rate N Industrial	Rate NT NT Total	Rate DS DS Total	Rates LFD, XD, IS Transport-Other	Total
1	HTY (Unadjusted) Use/Customer ("UPC") - MCF	15.90	81.20	76.80	234.60	345.00	1,151.20	693.70	7,029.70		
2	HTY UPC (Fully Adjusted) - MCF	15.90	83.20	76.60	231.00	307.60	1,184.80	691.10	7,065.70		
3	Change in UPC - MCF (L2 - L1)	0.00	2.00	(0.20)	(3.60)	(37.40)	33.60	(2.60)	36.00		
4	HTY Customers (Fully Adjusted)	20,477	519,287	82,349	3,105	44,978	673	20,620	1,295	975	693,759
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	-	1,039	(16)	(11)	(1,682)	23	(54)	47	-	(656)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	\$ -	\$ 13,549	\$ (103)	\$ (120)	\$ (18,006)	\$ 242	\$ (218)	\$ 154	\$ -	\$ (4,503)
7	Total Unit Revenue Adjustment (L6 / L5)	\$ -	\$ 13.0456	\$ 6.2820	\$ 10.7042	\$ 10.7042	\$ 10.7042	\$ 4.0676	\$ 3.3074	\$ -	\$ 6.8675
8	Distribution Margin Adjustment (L5 * L9)	\$ -	\$ 5,376	\$ (85)	\$ (43)	\$ (6,456)	\$ 87	\$ (206)	\$ 143	\$ -	\$ (1,184)
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)	\$ -	\$ 6,861	\$ -	\$ (74)	\$ (11,113)	\$ 149	\$ -	\$ -	\$ -	\$ (4,176)
11	PGC Unit Rate	\$ 6.6061	\$ 6.6061	\$ -	\$ 6.6061	\$ 6.6061	\$ 6.6061	\$ -	\$ -	\$ -	\$ -
12	EE&C Revenue Adjustment (L5 * L13)	\$ -	\$ 188	\$ (3)	\$ (0)	\$ (61)	\$ 1	\$ (2)	\$ 4	\$ -	\$ 127
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)	\$ -	\$ 650	\$ (10)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 640
15	USP Unit Rate	\$ 0.6257	\$ 0.6257	\$ 0.6257	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	MFC Revenue/Margin Adjustment (L5 * L17)	\$ -	\$ 156	\$ -	\$ (0)	\$ (49)	\$ 1	\$ -	\$ -	\$ -	\$ 107
17	MFC Unit Rate	\$ 0.1500	\$ 0.1500	\$ -	\$ 0.0291	\$ 0.0291	\$ 0.0291	\$ -	\$ -	\$ -	\$ -
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	\$ -	\$ 318	\$ (5)	\$ (2)	\$ (328)	\$ 4	\$ (10)	\$ 7	\$ -	\$ (16)
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)	\$ -	\$ 5,850	\$ (90)	\$ (45)	\$ (6,833)	\$ 92	\$ (216)	\$ 150	\$ -	\$ (1,093)
21	Total Unit Margin Adjustment (L20 / L5)	\$ -	\$ 5.6330	\$ 5.4755	\$ 4.0620	\$ 4.0620	\$ 4.0620	\$ 4.0315	\$ 3.2186	\$ -	\$ 1.6664

**UGI Utilities Inc.- Gas Division
 Historic Test Year- 12 Months Ended September 30, 2025
 (\$ in Thousands)**

Adjustment for WNA Revenues

		WNA	
		Revenue/Margin	
Rate R	Residential-Non Htg	\$	(55)
Rate R	Residential-Htg	\$	(10,180)
Rate RT	RT	\$	(1,407)
Rate N	Commercial-Non Htg	\$	(75)
Rate N	Commercial-Htg	\$	(2,485)
Rate N	Industrial	\$	(116)
Rate NT	NT Total	\$	(2,010)
	Total	\$	(16,327)

UGI Utilities Inc.- Gas Division
Historic 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
Actual HTY USP Rate	\$0.4693	\$0.4693	\$0.5770	\$0.5770	\$0.5770	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	
September HTY USP Rate	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	\$0.6257	
USP Rate Variance	\$0.1564	\$0.1564	\$0.0487	\$0.0487	\$0.0487	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0000	
Total Rate R Volumes	2,184	4,545	8,802	11,414	8,967	5,458	3,327	1,479	843	761	865	718	49,362
Total Rate R excl CAP Volumes	2,084	4,338	8,403	10,897	8,561	5,210	3,176	1,411	805	727	826	686	47,123
USP Rate Revenue Variance	\$326	\$678	\$1,314	\$1,704	\$1,339	\$815	\$497	\$221	\$126	\$114	\$129	\$107	\$7,370
Total Revenue Variance	\$326	\$678	\$1,314	\$1,704	\$1,339	\$815	\$497	\$221	\$126	\$114	\$129	\$107	\$7,370

UGI Utilities Inc.- Gas Division
Historic 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 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	(76)	(106)	(143)	(159)	(144)	(139)	(119)	(78)	(109)	(72)	(72)	(90)	(1,308)
Revenue Variance	(\$5)	(\$7)	(\$9)	(\$10)	(\$10)	(\$9)	(\$8)	(\$5)	(\$7)	(\$5)	(\$5)	(\$6)	(\$86)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
(\$ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)	(366)
\$/MCF	\$6.00
Excess Take Revenue/Margin	\$ (2,199)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2025
(\$ in Thousands)

Adjustment for STAS

	Unadjusted	@-0.12%	Adjusted	Revenue
	2025		2025	Adjustment
	TOTAL		TOTAL	Total
Residential-Non Htg	\$ (10)	\$ (10)	\$ (10)	0
Residential-Heating	\$ (797)	\$ (770)	\$ (770)	27
Residential-RT	\$ (70)	\$ (68)	\$ (68)	2
Total R/RT	\$ (877)	\$ (848)	\$ (848)	29
Commercial-Non Htg	\$ (11)	\$ (11)	\$ (11)	0
Commercial- Htg	\$ (220)	\$ (212)	\$ (212)	8
Industrial	\$ (10)	\$ (10)	\$ (10)	0
Com/Ind NT	\$ (86)	\$ (83)	\$ (83)	3
Total N/NT	\$ (327)	\$ (315)	\$ (315)	12
Total DS	\$ (63)	\$ (62)	\$ (62)	1
Total LFD	\$ (84)	\$ (83)	\$ (83)	1
Total XD-F	\$ -	\$ -	\$ -	-
Total Interruptible	\$ -	\$ -	\$ -	-
Grand Total	\$ (1,351)	\$ (1,308)	\$ (1,308)	43

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)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	16.0	22,934	366,944
Rate R	15.9	19,178	305,721
Rate RT	16.3	3,756	61,223

Residential Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	82.3	611,318	50,311,471
Rate R	82.7	533,332	44,119,383
Rate RT	79.4	77,986	6,192,088

Rate RT Total	76.5	81,742	6,253,311
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Commercial Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	363.6	4,584	1,666,742
Rate N	238.9	3,081	736,180
Rate NT	485.4	1,480	718,392
Rate DS	9,224.8	23	212,170

Commercial Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	526.2	65,162	34,288,244
Rate N	322.4	45,429	14,644,522
Rate NT	674.9	18,631	12,574,062
Rate DS	6,415.3	1,102	7,069,661

Rate Commercial NT Total	661.0	20,111	13,292,454
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Industrial

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	2,341.6	1,249	2,924,658
Rate N	655.6	613	401,902
Rate NT	2,053.9	456	936,578
Rate DS	8,812.1	180	1,586,178

Rate NT Total	691.8	20,567	14,229,032
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Rate DS Total	6,795.4	1,305	8,868,009
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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	16.0	23,545	376,720
Rate R	15.9	19,789	315,497
Rate RT	16.3	3,756	61,223

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	82.5	605,094	49,920,255
Rate R	83.0	527,108	43,728,167
Rate RT	79.4	77,986	6,192,088

Rate RT Total	76.5	81,742	6,253,311
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Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	363.6	4,606	1,674,742
Rate N	239.8	3,103	744,179
Rate NT	485.4	1,480	718,392
Rate DS	9,224.8	23	212,170

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	526.2	64,941	34,171,954
Rate N	321.4	45,208	14,528,893
Rate NT	674.9	18,631	12,574,062
Rate DS	6,414.7	1,102	7,068,999

Rate Commercial NT Total	661.0	20,111	13,292,454
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Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,341.6	1,260	2,950,416
Rate N	719.1	625	449,431
Rate NT	2,053.9	456	936,578
Rate DS	8,739.7	179	1,564,406

Rate NT Total	691.8	20,567	14,229,032
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Rate DS Total	6,783.4	1,304	8,845,576
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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	16.0	24,144	386,304
Rate R	15.9	20,447	326,043
Rate RT	16.3	3,697	60,261

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	82.7	597,939	49,449,555
Rate R	83.2	519,287	43,204,587
Rate RT	79.4	78,652	6,244,969

Rate RT Total	76.6	82,349	6,305,230
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Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	363.6	4,603	1,673,651
Rate N	231.0	3,094	714,839
Rate NT	485.4	1,486	721,304
Rate DS	10,326.4	23	237,507

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	526.2	64,781	34,087,762
Rate N	307.6	44,978	13,835,770
Rate NT	674.9	18,687	12,611,856
Rate DS	6,846.0	1,116	7,640,136

Rate Commercial NT Total	660.9	20,173	13,333,161
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Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,341.6	1,276	2,987,882
Rate N	1,184.8	673	797,359
Rate NT	2,053.9	447	918,093
Rate DS	8,156.6	156	1,272,430

Rate NT Total	691.1	20,620	14,251,254
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Rate DS Total	7,065.7	1,295	9,150,073
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UGI GAS

EXHIBIT SAE-8

**UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation**

Notes:

1/ Storage Trip Cost (\$/mcf) 0.1690

2/ Weekend Load Reduction Factor (%) 13.4%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 $WD = (1/(1 - WELF)) * WE$
 $= (1/(1 - 0.134)) * WE$
 $WD = 1.15 * WE$

EQ #2 $AVERAGE = [(5 * WD) + (2 * WE)] / 7$
 Step 1 $AVERAGE = [5 * ((1/(1 - WELF)) * WE)] + (2 * WE) / 7$
 $= [5 * (1/(1 - WELF)) + 2] * WE / 7$
 $= [5 * (1/(1 - 0.134)) + 2] * WE / 7$
 $7.75 * WE / 7$
 Step 2 $WE = 0.90 * AVERAGE$

4/ EQ #3 $Wkly Imbalance = 5 * (WD - AVERAGE) + 2 * (AVERAGE - WE)$
 $= (5 * WD) - (3 * AVERAGE) - (2 * WE)$
 $= (5 * (1/(1 - WELF)) * WE) - (3 * AVERAGE) - (2 * WE)$
 $= [(5 * (1/(1 - WELF)) - 2) * WE] - (3 * AVERAGE)$
 $= [(5 * (1/(1 - 0.134)) - 2) * WE] - (3 * AVERAGE)$
 $3.75 * WE - (3 * AVERAGE)$
 $0.38 * AVERAGE$

EQ #4 **Unit Cost Calculation (\$/mcf)**
 $= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST$
 $= [(0.38 * Average) / (7 * AVERAGE)] * 0.169$
 $0.05 * 0.169$
 0.0085

EQ #5 **Per Unit of Demand Calculation (\$/mcf per month)**
 $= Unit Cost Demand * 20 \text{ days}$
 $= 0.0085 * 20$
 0.1700

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 2024 through Sep 2025
- 3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days
- 4/ Assumes leveled 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) 1.4940 (A)

2/ Anticipated Average Monthly Imbalance % 0.9401% (B)

3/ Load Factors & MBS Rate Calculation

Rate	Load Factor	
DS	27.7%	(C)
LFD	58.6%	(C)
XD Firm	57.5%	(C)
Transportation System Average	51.4%	(D)

MBS Rate Formula

$$E = [(A / D) - ((A / D) * C)] * B$$

Rate	MBS Rate (\$/mcf)	
DS	0.0198	(E)
LFD	0.0113	(E)
XD Firm	0.0116	(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 2024 through Sep 2025

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 \$ 22,053,717		
Allocator 1/	93.47%	6.24%
Uncollectible Revenue Requirement	\$ 20,612,599	\$ 1,376,805
Total Proposed Revenue	\$ 869,313,264	\$ 292,438,718
MFC % 2/	2.37%	0.47%

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. 11

JOHN D. TAYLOR

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony

of

**John D. Taylor, Managing Partner
Atrium Economics, LLC**

Topics Addressed: **Cost of Service
Revenue Allocation
Rate Design
Weather Normalization Adjustment**

Dated: January 28, 2026

Table of Contents

I.	WITNESS IDENTIFICATION AND BACKGROUND.....	1
II.	ALLOCATED COST OF SERVICE STUDY OVERVIEW	2
III.	UGI GAS’S ALLOCATED COST OF SERVICE STUDY.....	9
IV.	PRINCIPLES OF SOUND RATE DESIGN.....	18
V.	UGI GAS’S REVENUE APPORTIONMENT	19
VI.	UGI GAS’S RATE DESIGN	23
VII.	WNA MECHANISM	32
VIII.	CONCLUSION.....	40

1 **I. WITNESS IDENTIFICATION AND BACKGROUND**

2 **Q. Please state your name, affiliation, and business address.**

3 A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC (“Atrium”)
4 as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400,
5 Hilton Head Island, SC 29926.

6
7 **Q. On whose behalf are you submitting this direct testimony?**

8 A. I am submitting testimony on behalf of UGI Utilities, Inc. – Gas Division’s (“UGI Gas”
9 or the “Company”) Gas Base Rate Case.

10
11 **Q. What is the purpose of your testimony in this proceeding?**

12 A. I prepared and am sponsoring UGI Gas’s fully allocated cost of service study (“ACOSS”),
13 which is found in UGI Gas Exhibit D. The ACOSS determines the embedded costs of
14 serving UGI Gas’s distribution customers associated with the Pennsylvania Public Utility
15 Commission (“Commission”) jurisdiction. I also support the apportionment, or allocation,
16 of the class revenue increase, and the Company’s rate design proposal. Finally, I am
17 supporting the Company’s Weather Normalization Adjustment (“WNA”) proposal.

18
19 **Q. Please describe your educational background and professional experience.**

20 A. UGI Gas Exhibit JDT-1 contains background information summarizing my education,
21 presentation of expert testimony, and other industry-related activities.

1 **Q. Please summarize the content of your testimony.**

2 A. My testimony consists of this introduction section (I) and the following six additional
3 sections: (II) Purpose and Principles of Cost Allocation, (III) UGI Gas’s Allocated Cost
4 of Service Study, (IV) Principles of Sound Rate Design, (V) UGI Gas’s Class Revenues,
5 (VI) UGI Gas’s Rate Design, and (VII) WNA Mechanism.

6

7 **Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?**

8 A. Yes. I am sponsoring Book IX, labeled as UGI Gas Exhibit D – Allocated Cost of Service
9 Study (Fully Projected) (“Exhibit D”). Exhibit D contains three sections for which an
10 index is provided on page 2 of Exhibit D. Also, I am sponsoring portions of Book I and
11 Book II, Section 53.53 et seq. of the Commission’s Regulations, Part IV-Rate Structure
12 and Cost Allocation. Related to the WNA proposal, I’m sponsoring the following exhibits:

- 13 • UGI Gas Exhibit JDT-2, Normal Heating Degree Days Report;
- 14 • UGI Gas Exhibit JDT-3, WNA Data Report; and
- 15 • UGI Gas Exhibit JDT-4, WNA Mechanism Policy Factors.

16

17 **II. ALLOCATED COST OF SERVICE STUDY OVERVIEW**

18 **Q. What is the general purpose and use of an ACOSS in regulatory proceedings?**

19 A. The purpose of an ACOSS is to allocate the gas distribution utility’s overall fully projected
20 future test year (“FPFTY”) costs to the various classes of service in a manner that reflects
21 the relative costs of providing service to each class. An ACOSS represents an analysis of
22 which customer or group of customers cause the utility to incur the costs to provide

1 service. The requirement to develop the ACOSS results from the nature of utility costs.
2 Utility costs are characterized by the existence of common costs. Common costs occur
3 when the fixed costs of providing service to one or more rate classes, or the cost of
4 providing multiple products to the same rate class, use the same facilities and the use by
5 one rate class precludes the use by another rate class.

6 In addition, utility costs may be fixed or variable in nature. Fixed costs do not change
7 with the level of gas throughput, while variable costs change directly with changes in gas
8 throughput. Most non-fuel related utility costs are fixed in the short run and do not vary
9 with changes in customers' loads. This includes the cost of distribution mains, service
10 lines, meters, and regulators.

11 Finally, the ACOSS provides different contributions to the development of
12 economically efficient rates and the cost responsibility by rate class. This is accomplished
13 through analyzing costs and assigning each rate class its proportionate share of the utility's
14 total revenues and costs within the test year. The results of these studies can be utilized
15 to determine the relative cost of service for each rate class to help determine the individual
16 class revenue responsibility and provide guidance with rate design. Using the cost
17 information per unit of demand, customer, and commodity developed in the ACOSS to
18 understand and quantify the allocated costs in each rate class is a useful step in the rate
19 design process to guide the development of rates.

1 **Q. Is the preparation of an ACOSS an exact science?**

2 A. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged
3 by identifying all of the capital and operating costs incurred by a utility to provide service
4 to all of its customers and then assigning or allocating those costs to individual rate classes
5 based on how those rate classes cause the costs to be incurred. The allocation of costs
6 using an ACOSS is a practical requirement of utility regulation since rates are based on
7 the cost of service for the utility under a cost-based regulatory model. As a general matter,
8 utilities must be allowed a reasonable opportunity to earn a return of and on the assets
9 used to serve their customers, with such return on being reflective of a fair rate of return.
10 This is the cost of service standard and equates to the revenue requirements for utility
11 service. The opportunity for the utility to earn its allowed rate of return depends on the
12 rates applied to customers producing revenues that equate to the level of the revenue
13 requirement.

14

15 **Q. Is there a guiding principle that supports the appropriate allocation of costs?**

16 A. Yes, a fundamental foundational principle, cost causation, should be followed to produce
17 accurate and reasonable results. Cost causation addresses the need to identify which
18 customer or group of customers causes the utility to incur particular types of costs, so the
19 analysis results in an appropriate allocation of the utility's total revenue requirement
20 among the various rate classes. In other words, the costs assigned or allocated to particular
21 customers should be those costs that the particular customers caused the utility to incur
22 because of the characteristics of the customers' usage of utility service.

1 **Q. How do you establish the cost and utility service relationships?**

2 A. An important element in the selection and development of a reasonable ACOSS
3 methodology is the establishment of relationships between customer requirements, load
4 profiles, and usage characteristics on the one hand and the costs incurred by the company
5 in serving those requirements on the other hand. To accomplish this, I reviewed UGI
6 Gas's expense and plant accounts, operational data, usage information, and conducted
7 interviews with UGI Gas employees. The details and data gathered provided information
8 on the key factors that cause the costs to vary and supported studies of the relative costs
9 of providing facilities and services for each rate class. From the results of those analyses,
10 methods of direct assignment and common cost allocation methodologies can be chosen
11 for the utility's plant and expense elements.

12

13 **Q. What are the steps to performing an ACOSS?**

14 A. A three-step analysis of the utility's total operating costs must be undertaken to establish
15 each customer class's cost responsibility. The three steps that are the basis to conduct an
16 ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

17

18 **Q. Please describe cost functionalization.**

19 A. The first step, cost functionalization, identifies and separates plant and expenses into
20 specific categories based on the various characteristics of utility operation. UGI Gas's
21 primary functional cost categories associated with natural gas distribution services include
22 gas supply, storage, transmission, distribution, and customer. Indirect costs that support

1 these functions, such as general plant and administrative and general expenses, are
2 allocated to functions using allocation factors related to plant and/or labor ratios, i.e.,
3 internal allocation factors.

4

5 **Q. Please describe cost classification.**

6 A. The second step, cost classification, further separates the functionalized plant and
7 expenses according to the primary factors that determine the amount of costs incurred.
8 These factors are: (1) the number of customers; (2) the need to meet the peak demand
9 requirements that customers place on the gas distribution system; and (3) the amount of
10 gas consumed by customers. These classification categories have been identified for
11 purposes of the ACOSS as: (1) customer costs; (2) demand costs; and (3) commodity
12 costs, respectively.

13

14 **Q. Please describe the types of costs contained in the customer, demand, and commodity**
15 **costs categories.**

16 A. Customer-related costs are incurred to attach a customer to the gas distribution system,
17 meter any gas usage, and maintain the customer's account. Customer costs are a function
18 of the number of customers served by the utility and continue to be incurred whether or
19 not the customer uses any gas. They may include capital costs associated with minimum
20 size distribution mains, services, meters, regulators, customer service, and accounting
21 expenses.

1 Demand or capacity related costs are associated with plant that is designed,
2 installed, and operated to meet maximum hourly or daily gas flow requirements, such as
3 the utility's transmission and distribution mains, or more localized distribution facilities
4 that are designed to satisfy individual customer maximum demands. Gas supply contracts
5 also have a capacity related component of cost relative to UGI Gas's requirements for
6 serving daily peak demands and the winter peaking season.

7 Commodity related costs are those costs that vary with the throughput sold to, or
8 transported for, customers. Costs related to gas supply are classified as commodity
9 because they vary with the amount of gas volumes purchased by UGI Gas for its
10 customers.

11

12 **Q. Please describe the cost allocation process.**

13 A. The final step is to allocate each functionalized and classified cost element to the
14 individual rate class. Costs are typically allocated on customer, demand, commodity, or
15 revenue allocation factors. From a cost-of-service perspective, the best approach is a
16 direct assignment of costs where costs are incurred by a customer or class of customers
17 and can be so identified. Where costs cannot be directly assigned, the development of
18 allocation factors by rate class uses principles of both economics and engineering. This
19 results in appropriate allocation factors for different elements of costs based on cost
20 causation. For example, we know from the way customers are billed that each customer
21 requires a meter. Meters differ in size and type depending on the customer's load
22 characteristics. These meters have different costs based on size and type. Therefore,

1 differences in the cost of meters are reflected by using a different average meter cost for
2 each class of service. Notably, UGI Gas has performed direct assignment analysis of its
3 most competitive negotiated rate customers who receive service under Rate XD, and those
4 direct assignment results are reflected in the ACOSS presented in UGI Gas Exhibit D.

5

6 **Q. Are there factors that can influence the overall cost allocation framework utilized by**
7 **a gas utility when performing an ACOSS?**

8 A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies
9 pertains to the concept of cost causation for purposes of allocating costs to customer
10 groups. Cost causation addresses the question – which customer or group of customers
11 causes the utility to incur particular types of costs? To answer this question, it is necessary
12 to establish a linkage between a utility’s customers and the particular costs incurred by the
13 utility in serving those customers. The factors that can influence the cost allocation used
14 to perform an ACOSS include: (1) the physical configuration of the utility’s gas system;
15 (2) the availability of data within the utility; and (3) the state regulatory policies and
16 requirements applicable to the utility.

17

18 **Q. Why are these considerations relevant to conducting UGI Gas’s ACOSS?**

19 A. It is important to understand these considerations because they influence the overall
20 context within which a utility’s cost study is conducted. In particular, they provide an
21 indication of where efforts should be focused for purposes of conducting a more detailed
22 analysis of the utility’s gas system design and operations and understanding the regulatory

1 environment in the state the utility operates in as it pertains to cost of service studies and
2 gas ratemaking issues.

3

4 **Q. How does the availability of data influence an ACOSS?**

5 A. The structure of the utility's books and records can influence the cost study framework.

6 This structure relates to attributes such as the level of detail, segregation of data by
7 operating unit or geographic region, and the types of load data available.

8

9 **Q. How do state regulatory policies affect a utility's ACOSS?**

10 A. State regulatory policies and requirements prescribe whether there are any historical
11 precedents used to establish utility rates in the state. Specifically, state regulations and
12 past precedents set forth the methodological preferences or guidelines for performing cost
13 studies or designing rates which can influence the proposed cost allocation method utilized
14 by the utility.

15

16 **III. UGI GAS'S ALLOCATED COST OF SERVICE STUDY**

17 **Q. Please describe the Atrium Model used in conducting the ACOSS filed in this**
18 **proceeding.**

19 A. UGI Gas has selected the Atrium excel based model ("Atrium ACOSS Model") to conduct
20 the ACOSS in this general base rate case. Atrium developed the Atrium ACOSS Model
21 on a proprietary basis for its consulting engagements, and it has been used in multiple

1 jurisdictions. This is the same model I sponsored in the Company's last base rate case at
2 Docket No. R-2024-3052716.

3
4 **Q. Please describe the process of performing UGI Gas's ACOSS presented in this filing.**

5 A. The detailed process description of UGI Gas's ACOSS analysis is presented in Exhibit D,
6 providing a full scope of the process including the development of allocation factors that
7 support various cost of service studies presented in this proceeding as discussed below.

8

9 **Q. Please discuss the content of Exhibit D.**

10 A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(1) and, in
11 particular, Exhibit A - Gas Utilities, by providing a cost of service study that fully
12 distributes the Pennsylvania jurisdictional costs of providing retail distribution service to
13 the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(1),
14 Exhibit A.

15 Exhibit D consists of three sections detailing the process of developing the ACOSS.
16 Section I – Introduction includes an introduction, the general purpose and process of the
17 ACOSS, as well as an overview of the excel-based fully functional ACOSS model
18 presented in this proceeding. Section II – UGI Gas's Cost of Service Procedures presents
19 the ACOSS development process specific to the Company, including the
20 Functionalization, Classification, and Allocation of costs. The Allocation section (Section
21 II.3) describes all internal and external allocation factors and the allocation processes used
22 in the ACOSS. The last section, Section III – UGI Gas's Cost of Service Results depicts
23 the results of the ACOSS, including revenue requirement apportionment, comparison of

1 cost of service with revenues under current and proposed rates, and development of rate
2 of return by customer class under current and proposed rates.

3

4 **Q. Please describe the content and schedules included in Exhibit D.**

5 A. Exhibit D contains a narrative description of the ACOSS procedures, provides details on
6 the allocation factors, and contains the following Schedules:

- 7 • Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and
8 Proposed Rates
- 9 • Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and
10 Unit Costs by Customer Class
- 11 • Schedule 3 - Cost of Service Allocation Study Detail by Account
- 12 • Schedule 4 - Account Balances and Allocation Methods
- 13 • Schedule 5 - External Allocation Factors
- 14 • Schedule 6 - Internal Allocation Factors

15

16 **Q. What was the source of the cost data analyzed in UGI Gas's ACOSS?**

17 All cost-of-service data was extracted from the Company's total cost of service (*i.e.*, total
18 revenue requirement) and schedules contained in this general rate case filing for the
19 FPFTY ending September 30, 2027. Where more detailed information was required to
20 perform various analyses related to certain plant and expense elements, the data were
21 derived from the historical books and records of the Company and information provided
22 by Company personnel.

1 **Q. How are UGI Gas’s rate classes structured for the purposes of conducting its**
2 **ACOSS?**

3 A. For UGI Gas’s ACOSS, I included six rate classes:

- 4 • Rate R - General Service – Residential & Residential Transportation
- 5 • Rate N - General Service – Non-Residential & Non-Residential Transportation
- 6 • Rate DS - Delivery Service
- 7 • Rate LFD - Large Firm Delivery Service
- 8 • Rate XD Firm - Extended Large Firm Delivery Service
- 9 • Rate IS - Interruptible Service

10

11 **Q. Do you propose any modification to the current customer classes?**

12 A. No. I am not proposing any modifications to the existing customer classes. The current
13 class structure aligns with the Company’s approved tariff schedules and is consistent with
14 the configuration adopted in the Company’s most recent general rate case, Docket No. R-
15 2024-3052716.

16

17 **Q. How did you classify and allocate the cost of distribution mains?**

18 A. I classified distribution mains as 100% demand related and allocated their costs in two
19 steps. First, a portion of the costs was directly assigned to Rate XD Firm based on an
20 analysis provided by the Company. Second, I allocated the remaining balance using the
21 Average and Excess (“A&E”) method.

1 **Q. Please describe the methodology used for the costs directly assigned to the XD**
2 **customers.**

3 A. For each customer, a distribution system analysis is performed to determine which assets
4 (including footage, diameter, material type, and vintage year) of the distribution system
5 are utilized to serve each Rate XD customer. Using the Company's plant records, the
6 costs and footage for these assets are summarized based on the footage assigned to the
7 customer as a percentage of the total footage for that asset. A portion of this cost is
8 allocated to each Rate XD customer based on the customer's throughput on that asset as a
9 percent of the asset total. The calculated costs for all assets assigned to each Rate XD
10 customer are summed to determine that customer's directly allocated costs. These
11 customer-level costs are then summed across all Rate XD customers to develop the direct
12 assignment for the Rate XD class.

13

14 **Q. Please describe the A&E method.**

15 A. The A&E method allocates costs based on a combination of average usage and peak usage
16 levels. This method is used to allocate costs on both the consistent usage (average
17 demand), and the additional capacity needed during peak times (excess demand). The
18 average demand is determined by the average daily throughput volumes per customer
19 class. The excess demand represents the additional capacity needed to meet the peak
20 demand or maximum usage levels for each customer class. These two factors are weighted
21 based on the system load factor, which is the ratio of average demand to peak demand for

1 the entire system. This factor determines the proportion of costs attributed to average
2 daily usage versus peak capacity requirements.

3

4 **Q. Can you explain the system load factor and its significance in this method?**

5 A. The system load factor is calculated as follows:

6
$$\text{Load Factor} = \text{Average Daily Throughput} \div \text{Peak Day Demand}$$

7 It indicates the efficiency of the system's utilization. A higher load factor suggests that
8 demand is relatively stable, reducing the need for excess capacity. This metric helps
9 balance the cost allocation between average usage and peak demand. UGI Gas's firm
10 service load factor for the FPFTY is 40.53%, which is the system load factor excluding
11 interruptible load. Therefore, the allocation assigns 40.53% of the costs to average daily
12 usage and 59.47% to peak demand.

13

14 **Q. Why is the interruptible load excluded from the load factor calculations?**

15 A. Interruptible load is excluded from the load factor calculations because it does not
16 contribute to the system's peak day demand, which is a critical driver of infrastructure. In
17 addition, interruptible customers are not assigned any excess load. Interruptible customers
18 agree to reduce or halt their gas usage during periods of high demand, meaning they do
19 not place the same capacity requirements on the distribution system as firm customers.
20 Including interruptible load would misrepresent the true cost drivers and unfairly allocate
21 costs to customers who do not rely on guaranteed peak capacity.

1 **Q. Has the A&E method been approved by the Commission?**

2 A. Yes. The A&E method was approved by the Commission in PECO Energy Company's
3 rate case at Docket No. R-2020-3018929.

4

5 **Q. Did you consider other classification or allocation methods?**

6 A. Yes. I considered the customer/demand classification method and the Peak and Average
7 ("P&A") allocation method. However, the Commission has not traditionally recognized
8 the customer component of gas mains, which means the customer/demand classification
9 method is not consistent with past Commission orders.¹ The P&A allocation method has
10 also been evaluated for use in past Pennsylvania rate cases and applies a fixed 50/50
11 weighting instead of relying on the system load factor.

12

13 **Q. How do the allocation results differ between the A&E method and the P&A method
14 for UGI Gas in this case?**

15 A. The allocation results for each method are presented below in Table 1. The A&E method
16 allocates a higher percentage of costs to Rate R (46.8% vs. 44.7%) and Rate N (31.6% vs.
17 28.9%), reflecting its reliance on the system load factor. On the other hand, the P&A
18 method allocates a higher percentage of costs to Rate LFD (15.4% vs. 11.7%) and
19 Interruptible (4.3% vs. 3.5%), due to its 50/50 weighting of average demand within the
20 peak portion. These differences illustrate how the P&A method allocates more costs to

¹ *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order entered February 19, 2021), p. 217.

1 higher-load factor customers than the A&E method, despite those customers having more
2 efficient use of the system.

3

4 **Table 1 – Comparison of Mains Allocators of the Company’s ACOSS**

	Rate R	Rate N	Rate DS	Rate LFD	Interruptible
A&E	46.8%	31.6%	6.4%	11.7%	3.5%
P&A	44.7%	28.9%	6.7%	15.4%	4.3%

5

6 **Q. Does UGI Gas’s ACOSS include gas commodity costs?**

7 A. Yes. The gas costs reflected in the ACOSS correspond to gas cost revenues that have a
8 neutral impact on the study’s results, resulting in a net-zero effect.

9

10 **Q. Please summarize the results of the Company’s ACOSS.**

11 A. Table 2 below presents a summary of the Company’s ACOSS that can be reviewed in
12 Schedule 1 of Book IX, UGI Gas Exhibit D. The ACOSS shows an overall revenue
13 requirement of \$1,234.7 million and a resulting deficiency of \$99.4 million. The revenue
14 deficiency/excess for each rate class shows revenue increases or decreases necessary to
15 get the classes to their cost to serve.

1

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	\$ 794,595	\$ 895,723	\$ (101,128)	12.7%	5.2%	0.89	0.96
Rate N	269,032	292,438	(23,405)	8.7%	6.5%	0.92	0.99
Rate DS	36,024	34,197	1,827	-5.1%	9.3%	1.05	1.14
Rate LFD	58,792	54,870	3,922	-6.7%	9.6%	1.07	1.16
Rate XD Firm	39,155	26,027	13,128	-33.5%	17.0%	1.45	1.56
Rate IS	22,953	16,665	6,288	-27.4%	14.3%	1.37	1.48
Total Base	1,220,551	1,319,920	(99,369)	8.1%	6.5%	0.93	1.00
Other Revenues	14,131	14,131	-				
Total Company	1,234,682	1,334,051	(99,369)				

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Q. Have you prepared more detailed reports of UGI Gas's ACOSS results?

13

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

14

15

16

² See Exhibit D, Schedule 1, lines 13, 52, 57, 24, 26, and 27.

Percent Change = Class Revenue (Deficiency)/Sufficiency ÷ Current Revenues

1 presents the resulting allocations by customer class of UGI Gas’s proposed revenue
2 requirement based on the results of the computations included in the ACOSS.

3

4 **IV. PRINCIPLES OF SOUND RATE DESIGN**

5 **Q. Please identify the rate design principles utilized in developing the Company’s rate**
6 **design proposals.**

7 A. The rate design principles below draw heavily upon the “Attributes of a Sound Rate
8 Structure” developed by James Bonbright in Principles of Public Utility Rates.³ Each of
9 these principles plays an important role in analyzing the rate design proposals of UGI Gas
10 and provides a roadmap that helps guide utilities and regulators when considering how to
11 achieve utility rates that are fair, efficient, practical, and reasonable. The foundation of
12 rates should include:

- 13 • Fairness: Rates should be fair to all customer classes, avoiding undue
14 discrimination.
- 15 • Efficiency: Rates should promote the efficient use of resources and encourage
16 conservation while avoiding undue restriction of economic use.
- 17 • Simplicity: Rates should be simple and understandable for customers.
- 18 • Stability/Gradualism: Rates should provide bill stability for customers and revenue
19 stability for the utility.
- 20 • Reflective of Costs: Rates should reflect the cost of providing service to different
21 customer classes.

³ James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

- 1 • Revenue Sufficiency: Rates should generate enough revenue to cover the utility’s
2 costs, including a reasonable return on investment.

3 In addition, these principles are consistent with Pennsylvania practice and
4 precedent, including the *Lloyd* decision,⁴ where the Commonwealth Court indicated that
5 cost of service is the “polestar” of ratemaking but that other factors, including those listed
6 above, can be considered as well.

7
8 **Q. How are these principles translated into the design of rates?**

9 A. The overall rate design process, which includes both the apportionment of the revenues to
10 be recovered among rate classes and the determination of rate structures within rate
11 classes, consists of finding a reasonable balance between the above-described criteria or
12 guidelines that relate to the design of utility rates. Economic, regulatory, historical, and
13 social factors all enter the process. In other words, both quantitative and qualitative
14 information are evaluated before reaching a final rate design determination. Out of
15 necessity, the rate design process must be, in part, influenced by judgmental evaluations.

16
17 **V. UGI GAS’S REVENUE APPORTIONMENT**

18 **Q. Please describe the approach used by UGI Gas to allocate its proposed \$99.4 million**
19 **revenue increase among its customer rate classes.**

20 A. UGI Gas’s proposed allocation of the revenue increase is informed by the results of the
21 ACOSS and reflects a deliberate effort to move all rate classes closer to the overall system

⁴ *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

1 rate of return, thereby reducing the subsidies that currently exist between classes. This
2 approach is consistent with long-standing regulatory practice and precedent, including the
3 *Lloyd* decision and the Commission's Order on remand approving the settlement in that
4 case.

5 The benchmark option evaluated under UGI Gas's proposed total revenue level
6 was to adjust the revenue level for each customer class so that the revenue-to-cost for each
7 class was equal to 1.00. This is shown above in Table 2 where the changes in each classes'
8 revenues would be set to their deficiency or surplus. It was decided that this fully cost-
9 based option was not the preferred solution to the interclass revenue issue, given the large
10 increase required to move some classes to parity. After discussions with the Company,
11 the increase proposed in this case was allocated based on a desire to move toward full
12 parity over time while addressing issues of gradualism. To accomplish this, the Company
13 first reflected the slight rate decreases for competitively negotiated classes XD and IS in
14 the mechanics of the calculations, resulting from incorporating the current Distribution
15 System Improvement Charge ("DSIC") rider into base rates. Second, Rate N was assigned
16 an increase to move them to parity, equivalent to 1.18 times the system increase. Finally,
17 Rates DS and LFD were assigned increases that correct approximately two-thirds of the
18 class's over-earning relative to the system-average rate of return. While there are various
19 yardsticks used to measure the degree of movement toward cost of service, the Company
20 evaluated two metrics: (1) the percentage movement towards the system rate of return;
21 and (2) the reduction in the subsidies occurring between classes. In addition, the
22 Company's proposal results in keeping the residential average monthly bill increase under

1 \$10, and with these considerations, the Company is proposing the revenue changes shown
 2 in Table 3 below.

3 **Table 3 – Proposed Class Revenue Apportionment**
 4 **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	\$ 794,595	\$ 869,272	\$ 74,677	9.4%	7.4%	0.97
Rate N	269,032	\$ 292,418	23,386	8.7%	8.2%	1.00
Rate DS	36,024	\$ 36,732	708	2.0%	9.4%	1.07
Rate LFD	58,792	\$ 59,528	736	1.3%	9.4%	1.08
Rate XD Firm	39,155	\$ 39,090	(64)	-0.2%	16.4%	1.44
Rate IS	22,953	22,879	(73)	-0.3%	13.7%	1.37
Total Base	\$ 1,220,551	\$ 1,319,920	\$ 99,369	8.1%	8.2%	1.00

6

7 **Q. To what degree does the Company’s proposed revenue apportionment move the**
 8 **classes toward their cost of service?**

9 A. The Company’s proposed revenue apportionment results in the reduction of the existing
 10 rate subsidies and excesses among the Company’s rate classes, moving classes toward the
 11 overall system rate of return. From a class cost of service standpoint, this type of class
 12 movement and reduction in class rate subsidies is desirable, as it brings class revenues and
 13 rates closer to the indicated cost of service for each rate class.

14 Table 4 below compares the current and proposed rates of returns and parity ratios.
 15 The Company’s proposal moves the return for all rate classes closer to the Company’s
 16 proposed return. Likewise, parity ratios move closer to the desired 1.0 level.

⁵ See Exhibit D, Schedule 1, lines 10, 52, 58, 61, 70, and 72.

**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	\$ 794,595	\$ 869,272	5.2%	7.4%	0.96	0.97
Rate N	\$ 269,032	\$ 292,418	6.5%	8.2%	0.99	1.00
Rate DS	\$ 36,024	\$ 36,732	9.3%	9.4%	1.14	1.07
Rate LFD	\$ 58,792	\$ 59,528	9.6%	9.4%	1.16	1.08
Rate XD Firm	\$ 39,155	\$ 39,090	17.0%	16.4%	1.56	1.44
Rate IS	\$ 22,953	\$ 22,879	14.3%	13.7%	1.48	1.37
Total Base	\$ 1,220,551	\$ 1,319,920	6.5%	8.2%	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 subsidies, proposed subsidies, and the reduction in subsidies for all customer classes resulting from the Company's proposed revenue apportionment.

Table 5 - Comparison of Current and Proposed Subsidies (\$000)⁷

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Rate R	\$ (34,867)	\$ (26,451)	\$ 8,416
Rate N	(23)	(20)	3
Rate DS	4,965	2,535	2,430
Rate LFD	9,160	4,658	4,502
Rate XD Firm	13,654	13,063	590
Rate IS	7,112	6,215	897
Total Company	\$ -	\$ -	\$ -

⁶ Exhibit D, Schedule 1, lines 10, 52, 24, 70, 27, and 73.

⁷ See Exhibit D, Schedule 1, lines 35 and 63. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

1 **VI. UGI GAS'S RATE DESIGN**

2 **Q. Please summarize the rate design changes UGI Gas has proposed in this rate**
3 **proceeding.**

4 A. In general, UGI Gas's rate design strategy is to make incremental movements toward
5 reflecting the Company's relative cost of serving each rate class to provide natural gas
6 distribution service to those customers. UGI Gas has proposed the following rate design
7 changes to its current tariff schedules:

- 8 - Rate R – Increase in the monthly customer charge from \$16.25 to \$23.00, with the
9 remaining proposed increase to be recovered in the volumetric charge.
- 10 - Rate N – Increase in the monthly customer charge from \$36.42 to \$39.00, with the
11 remaining proposed increase to be recovered in the volumetric charge.
- 12 - Rate DS – Increase in the monthly customer charge from \$300 to \$353, with the
13 remaining proposed increase to be recovered in the volumetric charge.
- 14 - Rate LFD – Increase in the volumetric charge from \$1.3831 per Mcf to \$1.4173 per
15 Mcf.
- 16 - Rate XD Firm – Decrease equivalent to the DSIC rider amount.
- 17 - Rate IS – Decrease equivalent to the DSIC rider amount.

18
19 **Q. Has the Company prepared a detailed comparison of the Company's current and**
20 **proposed rates and resulting revenues by rate class?**

21 A. Yes. UGI Gas Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A.
22 Epler, Statement No. 10, presents a detailed comparison of current and proposed revenues
23 for each of UGI Gas's rate classes.

1 **Q. What billing determinants were used to develop the Company’s proposed base rates**
2 **in this proceeding?**

3 A. Consistent with the Settlement Agreement approved by the Commission in Docket Nos.
4 R-2024-3052716 et al., the Company evaluated the use of a ten-year historical period and
5 determined that a ten-year historical average of heating degree days (“HDDs”) ending
6 December 31, 2024, is a more appropriate basis for both base-rate billing determinants
7 and WNA calculations. In support of this conclusion, I am sponsoring the Normal Heating
8 Degree Days Report in UGI Gas Exhibit JDT-2, which evaluates long-term weather trends
9 and normalization alternatives and recommends adoption of a ten-year historical average
10 to reflect more recent weather conditions. Specifically, this analysis was undertaken
11 pursuant to the settlement agreement approved by the Commission on September 11,
12 2025, at Docket Nos. R-2024-3052716, et al. which established the following requirement:

13 UGI Gas will include in its filing a report and recommendation on the use
14 of a rolling ten-year historical average period to be used to calculate its
15 normal heating degree day amounts for purposes of the WNA, as well as
16 the use of a ten-year historical average period for purposes of determining
17 projected sales and billing determinants in base rates. (p.12)

18 As set forth in UGI Gas Exhibit JDT-2, the Company proposes that the 10-year
19 normals be updated in conjunction with each future rate case filing. This would replace
20 the Company’s current practice, wherein it used 15 years of weather data updated every
21 five years, with the last update – the one that supported the rates established in Docket R-
22 2024-3052716 – based on data ending on December 31, 2019.

1 **Q. What factors drove the change in billing determinants in this case compared to prior**
2 **rate cases?**

3 A. Two primary factors contributed to the change in billing determinants in this case. First,
4 as I just described, in the prior proceedings, the Company relied on a fifteen-year historical
5 average ending in 2019. Under the Company's current methodology, it was required to
6 update its normal weather in this proceeding. Updating that methodology alone, by
7 advancing the fifteen-year period to include more recent data, would have replaced
8 approximately one-third of the historical observations with newer years that generally
9 reflect lower heating degree days. As a result, even without a change to a ten-year
10 historical average of HDDs, normalized billing determinants would have declined due to
11 the inclusion of warmer recent weather.

12 Second, in compliance with the Settlement Agreement, the Company evaluated
13 and ultimately is proposing the use of a ten-year historical average ending December 31,
14 2024. As demonstrated in Exhibit JDT-2, a ten-year period more closely aligns with
15 observed recent weather patterns and the long-term downward trend in heating degree
16 days, while avoiding the overstatement of heating demand that can occur when older,
17 colder years remain embedded in the normalization period.

18
19 **Q. How does the ACOSS support the proposed increases to customer charges?**

20 A. Atrium's ACOSS model allows for developing the total revenue requirement by functions
21 and classifications. As such, we can see directly the revenue requirement associated with
22 the customer classification and the respective functions that form this revenue

1 requirement. Table 6 below provides the information related to the current and proposed
2 customer charges for Rates R, N, and DS, compared to the customer-related unit cost per
3 customer per month.

4 **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	16.25	23.00	54.03	79.04
Rate N	36.42	39.00	70.69	224.16
Rate DS	300.00	353.00	542.90	2,201.57

5
6 As seen in the above table, the proposed increases in customer charges are still under the
7 customer-related unit cost identified in the ACOSS. These include the customer portion
8 of distribution facilities, as well as customer service and billing costs.

9
10 **Q. Can you please discuss the results in Table 6 above within the context of the**
11 **Company’s proposed customer charges and past Commission precedent?**

12 A. Yes, past Commission precedent defines customer-related costs for inclusion in a
13 customer charge as costs associated with meters and services and related operations and
14 maintenance (“O&M”) expenses, meter reading and billing and collection expenses, meter
15 data management systems, and related employee benefits, administrative and general
16 expenses. The Company is proposing a Rate R customer charge of \$23.00, which is below
17 the \$54.03 within Table 6 above, and represents meter reading, customer service, and

⁸ See Exhibit D, Schedule 2, lines 118 and 119.

1 billing and collection expenses. These are all costs historically allowed by the
2 Commission in a customer charge. Taking into consideration past precedent in
3 Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company
4 is proposing to move the Rate R customer charge to \$23.00. Similarly, the Company is
5 proposing customer charge increases to Rate N and Rate DS that are still well below the
6 customer related unit cost for these rates.

7

8 **Q. Why are setting customer charges more in alignment with the fixed cost of service**
9 **an important outcome of ratemaking?**

10 A. These proposed customer charges help to reduce customer bill volatility, alleviate a
11 significant portion of the instability in the Company's margin recovery, are fair to
12 customers, are easily understood, convey more appropriate price signals with respect to
13 recovery of fixed utility costs, benefit low-income customers that have higher than average
14 use, and are not regressive in application to low-income customers who may have little
15 control over their use of energy and are negatively impacted when recovering more costs
16 in volumetric charges.

17 Establishing higher monthly fixed charges helps to equalize the contribution each
18 customer within a class makes towards recovery of the fixed costs attributable to this class.
19 This method of cost recovery is preferable to including such costs in the volumetric
20 charges, which has the effect of causing some customers to pay too much while others pay
21 too little. The customer charges provide for recovery of a portion of the Company's fixed
22 costs, which are incurred solely because of the existence of customers connected to the

1 system. These costs, such as the expense of reading meters and billing, occur regardless
2 of whether natural gas is used and are not related to demands placed on the system. The
3 proposed customer charge increases will also help to ensure the Company’s recovery of a
4 greater portion of its fixed costs of providing service. Inasmuch as costs are not related to
5 usage, they should be recovered, to the extent possible, through a tariff mechanism that
6 does not depend upon volumetric billing.

7 In terms of understandability, customers easily recognize fixed cost charges and
8 are used to these pricing structures in their everyday lives. Because these costs do not
9 vary with the customer’s usage, it is perfectly understandable that the charge should not
10 vary as well.

11

12 **Q. Please expand on why an increase in the Rate R customer charge would benefit low-**
13 **income customers.**

14 A. There is often a common misconception that low-income customers are low-usage
15 customers. This is not a correct characterization of low-income customers on the
16 Company’s system who are indeed higher-use customers. According to the Company’s
17 historical residential customer billing data⁹, the average use for confirmed low-income
18 customers not enrolled in the Customer Assistance Program (“CAP”)¹⁰ is 86.7 Mcf/year.

⁹ Based on three full years (2022, 2023 and 2024) of residential customer billing data. This dataset included individual monthly usage levels for each customer, along with key identifying attributes that enabled segmentation of the residential class for comparative purposes.

¹⁰ Customers with Confirmed Low-Income indicator as of January 2025. Confirmed Low Income indicator is applied when a customer provides proof of income and is subsequently enrolled in CAP, participated in Low Income Usage Reduction Program (“LIURP”; 200% Federal Poverty Income Guidelines (“FPIG”)) or received an Operation Share grant (250% FPIG) or a Low Income Home Energy Assistance Program (“LIHEAP”) grant (150% FPIG) within prior 12 months.

1 This is 14% higher than the average of the Company's residential non-low-income
2 customer use of 76.0 Mcf/year.

3 Also, all else being equal, higher customer charges necessitate lower variable
4 charges. The collection of costs through fixed or volumetric charges is only the means of
5 collecting the revenue to cover costs for a specific customer class. The amount of total
6 revenue that must be recovered does not change. Higher usage customers pay more when
7 more fixed customer costs are embedded in the volumetric rates. This creates a social
8 equity concern, as customers who can afford to reduce their usage through energy
9 efficiency investments can decrease their bills by making such investments, while those
10 customers who cannot afford to make energy efficiency investments will see increases in
11 their bills. Examples of those who could possibly afford to reduce their usage include
12 higher-income households who can undertake more expensive energy efficiency
13 measures. While some environmental advocates may prefer that households stop using
14 natural gas altogether, families still use gas as an economic energy source for basic human
15 needs such as keeping themselves warm, cooking, and caring for themselves.

16 Further, recovering fixed costs in volumetric charges places regressive burdens on
17 low-income households who have to make decisions to reduce their gas usage, which
18 impacts their quality of life. Families use gas as an economic energy source for basic
19 human needs such as keeping themselves warm, to cook, and care for themselves. For
20 many households, particularly low-income customers, a substantial portion of natural gas
21 consumption reflects non-discretionary usage necessary to meet basic human needs and

1 cannot be meaningfully reduced through “just use less” through price signals, absent the
2 ability to invest in more efficient equipment or building improvements.

3 Lastly, considerations relating to the intersection of income and rate design would
4 be amiss if they did not include discussions relating to UGI Gas’s low-income programs.
5 UGI Gas has available a continuum of low-income targeted programs, beyond CAP,
6 including facilitating Low-Income Home Energy Assistance Program (“LIHEAP”), and
7 offering Low-Income Usage Reduction Program (“LIURP”) and weatherization
8 assistance, as well as Operation Share to address customers experiencing economic
9 hardship.

10

11 **Q. Have you conducted an analysis of the difference between the current \$16.25 monthly**
12 **residential customer charge and the proposed \$23.00 a month charge on low-income**
13 **customers?**

14 A. Yes. Table 7 compares the amount a confirmed non-CAP low-income customer with an
15 average usage of 86.7 Mcf/year would pay between the customer charge and the
16 volumetric charge under the Company’s proposal (Scenario A) of increasing the monthly
17 customer charge to \$23.00, and Scenario B, which keeps the monthly customer charge
18 unchanged at \$16.25.

1 **Table 7 – Comparison of Annual Charges for Average CAP Customer¹¹**

Average LI Customer (non-CAP)	Scenario A	Scenario B	B - A	% change
Customer Charges	\$ 276.00	\$ 195.00	\$ (81.00)	-41.5%
Distribution Charges	592.61	680.78	\$ 88.18	13.0%
Total Annual Charges	\$ 868.61	\$ 875.78	\$ 7.18	0.8%

2

3 The comparison shows that while the Company’s proposal increases the annual

4 customer charges by \$81.00 or 41.5%, the increase is offset by the \$88.18 or 13.0% lower

5 distribution charges. In other words, by not changing the current customer charge,

6 customers may face higher overall costs because of the increase in distribution charges.

7 This suggests that any policy or pricing adjustment leading to keeping the customer charge

8 unchanged would shift more costs to the variable distribution component, increasing the

9 financial burden on low-income customers, close to 1%, over a year. As previously stated,

10 a volumetrically weighted rate design conveys improper price signals to customers

11 because it recovers fixed costs through the volumetric components of the utility’s rate

12 structure. When this undesirable situation exists, it can: (1) increase revenue variability

13 due to factors beyond the utility’s ability to influence; (2) fail to account for cost

14 differences between and within customer classes; (3) promote inefficient use of the

15 utility’s system; and (4) needlessly inflate bills in the winter months. The important policy

16 point in this discussion is that it makes no economic sense to send the wrong economic

17 price signals to all customers in order to supposedly benefit a small subset of low-income

¹¹ Scenario A uses a monthly customer charge of \$23.00 and distribution charges of \$6.8383/Mcf, as proposed by the Company. Scenario B uses the current monthly customer charge of \$16.25 and distribution charges of \$7.8558/Mcf, which would be necessary to recover Rate R’s proposed revenue.

1 customers. It is far more efficient to address the issues of low-income customers directly
2 through programs and assistance, such as the Company’s CAP.

3

4 **VII. WNA MECHANISM**

5 **Q. What is the Company’s proposal regarding WNA in this proceeding?**

6 A. UGI Gas is requesting the Commission to extend the current WNA pilot mechanism for
7 an additional five (5) years after its current expiration in October 2027. This request
8 follows the settlement agreement approved by the Commission on September 11, 2025, at
9 Docket Nos. R-2024-3052716, et al. which established the following:

10 UGI Gas’s WNA Pilot will end on October 31, 2027, unless affirmatively
11 extended or otherwise permitted by Commission order. Should UGI Gas
12 request a continuation or modification of the WNA for the period on or after
13 November 1, 2027, it may file a stand-alone Petition or incorporate into a
14 base rate proceeding to be filed no later than January 31, 2026. (p.12)

15

16 **Q. Has the Commission recently approved similar WNA mechanisms?**

17 A. Yes. For example, in its most recent Final Order in the Columbia Gas of Pennsylvania
18 (“Columbia”) case, issued in December 2025, the Commission explicitly approved the
19 continuation of Columbia's WNA mechanism “to allow it a reasonable opportunity to earn
20 up to its Commission-authorized revenue requirement.”¹²

¹² Pa. PUC v. Columbia Gas of Pa., Inc., Docket No. R-2024-3067174, Final Order at 301 (Dec. 4, 2025).

1 **Q. Has the Company complied with the WNA stipulations from the settlement**
2 **agreements in prior rate cases?**

3 A. Yes. As mentioned above, I am sponsoring the Normal Heating Degree Days Report in
4 UGI Gas Exhibit JDT-2, which supports utilizing a 10-year weather history, and was
5 agreed upon in Docket No. R-2024-3052716, et al. In addition, as explained by Company
6 witness Brian J. Meilinger, UGI Gas Statement No. 12, the Company has reviewed the
7 WNA Pilot communication materials, and it has expanded its reporting as agreed upon in
8 Docket No. R-2024-3052716, et al. Lastly, UGI Gas Exhibit JDT-3 provides the WNA
9 data requested by the parties in the settlement agreements in Dockets No. R-2021-3030218
10 and No. R-2024-3052716.¹³

11

12 **Q. How does the use of a ten-year historical average for billing determinants relate to**
13 **the Company's WNA?**

14 A. The use of a ten-year historical average serves a consistent and complementary role in
15 both base-rate development and WNA operation. Base rates are established using billing
16 determinants normalized to the same ten-year weather baseline against which actual
17 weather will later be compared under the WNA. Maintaining this consistency ensures that
18 the WNA functions as intended by adjusting revenues solely for deviations between actual
19 weather and the normalized weather assumptions embedded in rates.

¹³ The Company has filed five reports with the Commission since November 30, 2023, containing WNA data from April 2023 through October 2025. These reports are available at <https://www.puc.pa.gov/pdocs/1807398.pdf>, <https://www.puc.pa.gov/pdocs/1835933.pdf>, <https://www.puc.pa.gov/pdocs/1857431.pdf>, <https://www.puc.pa.gov/pdocs/1885030.pdf>, and <https://www.puc.pa.gov/pdocs/1904492.pdf>

1 As explained in Exhibit JDT-2, using different weather baselines for rate-setting
2 and WNA calculations could introduce misalignment and unintended over or under
3 recovery. By applying the same ten-year historical average for both purposes, the
4 Company preserves methodological integrity and ensures that customers and the Company
5 are treated fairly when weather conditions differ from normal.

6

7 **Q. Does the use of a ten-year historical average eliminate the need for a WNA?**

8 A. No. While a ten-year historical average better reflects recent weather conditions, actual
9 heating degree days will continue to vary from year to year in ways that cannot be
10 predicted with certainty. Accordingly, the WNA remains an important mechanism to
11 address year-to-year weather variability by reconciling revenues to the normalized
12 assumptions used to set rates, thereby protecting both customers and the Company from
13 the financial effects of abnormal weather.

14 Using a ten-year historical average also improves the definition of “normal”
15 weather by placing greater weight on more recent conditions. As a result, deviations
16 between actual weather and normalized assumptions are expected to be smaller, on
17 average, than under a longer historical period that includes older, less representative data.
18 This improved alignment is expected to reduce the magnitude of WNA surcharges or
19 credits over time, while preserving the WNA’s role in addressing unavoidable weather
20 variability.

1 **Q. Please describe the Company’s proposed WNA.**

2 A. After adopting the modifications to the current WNA pilot pursuant to the Commission-
3 approved settlement at Docket No. R-2024-3052716, UGI Gas’s WNA mechanism
4 functions as follows:

5 i) It adjusts the usage in customer bills based on deviations from normal weather, as
6 measured by Heating Degree Days (“HDDs”), by comparing actual HDDs
7 (“AHDDs”) to normal HDDs (“NHDDs”) based on a 15-year weather history.

8 ii) It includes a 3% deadband, meaning no adjustment is made unless the weather deviates
9 by more than $\pm 3\%$ from normal. This prevents minor weather variations from
10 triggering bill changes and ensures that adjustments occur only when there are material
11 deviations.

12 iii) It applies to Residential (excluding CAP customers) and Small Commercial classes.

13 iv) It applies during the heating season months of October through April. By excluding
14 non-heating season usage and focusing on the weather-sensitive portion of
15 consumption, the mechanism is carefully targeted and limited in scope. Specifically,
16 the WNA no longer applies in May.

17

18 **Q. Why is a WNA mechanism necessary for UGI Gas’s rate structure?**

19 A. UGI Gas’s current rate design recovers significant fixed costs through volumetric charges.
20 Weather-driven usage swings can cause under-recovery in warm winters and over-
21 recovery in cold winters. The WNA stabilizes this to provide the Company a reasonable

1 opportunity to recover its authorized revenue requirement while protecting customers
2 from additional charges in colder than normal winters.

3

4 **Q. Can you elaborate on the relationship between fixed costs and usage-based recovery**
5 **in UGI Gas’s current rate design?**

6 A. UGI Gas’s current rate design recovers a significant portion of its fixed costs, such as
7 infrastructure, maintenance, and administrative expenses, through volumetric charges
8 based on customer usage. Because revenues are recovered through volumetric rates
9 established using billing determinants that reflect normal weather conditions, periods of
10 warmer-than-normal weather result in lower-than-expected gas usage and corresponding
11 under-recovery of fixed costs, even though those costs do not vary with consumption.
12 Conversely, colder-than-normal weather can lead to over-recovery. This mismatch creates
13 volatility for both customers and the utility. The WNA mechanism helps address this by
14 normalizing revenues to reflect normal weather conditions, ensuring that fixed costs are
15 recovered more consistently with what was authorized by the Commission when it
16 approved current rates.

17

18 **Q. What portion of UGI Gas’s fixed costs is recovered through its current volumetric**
19 **distribution charges?**

20 A. As shown on UGI Gas Exhibit E – Proof of Revenue, at current rates, approximately 72%
21 of base rate distribution revenues for Rate R is recovered through the volumetric
22 distribution charge. For Rate N, approximately 81% of base rate distribution revenue is

1 recovered through the volumetric distribution charge. This clearly indicates that even
2 though UGI Gas’s distribution costs are fixed, there is a risk of over- or under-recovery,
3 for the vast majority of costs, resulting in the need for the WNA.

4

5 **Q. Are there alternative rate designs which more closely align fixed cost recovery with**
6 **distribution charges and minimize potential under- and over-recovery due to**
7 **weather?**

8 A. Yes. Straight-Fixed-Variable (“SFV”) rate design would accomplish that goal.

9

10 **Q. How would a transition toward a SFV rate design help mitigate under- and over-**
11 **recovery risks?**

12 A. A transition to a SFV rate design would reduce UGI Gas’s reliance on usage-based charges
13 to recover fixed costs. Under the current structure, a significant portion of fixed costs, such
14 as infrastructure and maintenance, are recovered through volumetric rates, making
15 revenues highly sensitive to weather-driven consumption changes. SFV shifts recovery of
16 fixed costs to a fixed monthly charge, ensuring that these costs are collected consistently
17 regardless of seasonal usage fluctuations. This approach mitigates under-recovery risks
18 during mild winters and over-recovery during colder-than-normal periods, providing
19 greater revenue stability and aligning cost recovery with cost causation principles.

1 **Q. How does UGI Gas’s proposed WNA align with the factors the Commission may**
2 **consider when evaluating this alternative ratemaking mechanism?**

3 A. Exhibit JDT-4 details how UGI Gas’s proposed WNA aligns with each of the fourteen
4 items identified within the Statement of Policy as outlined by the Commission in the
5 alternative rate making Docket No. M-2015-2518883. However, it is important to note
6 that the Statements of Policy language¹⁴ suggests that the Commission intends to consider
7 these elements, but not all of them may be relevant or deemed required in order to
8 determine whether a proposal is just and reasonable.

9

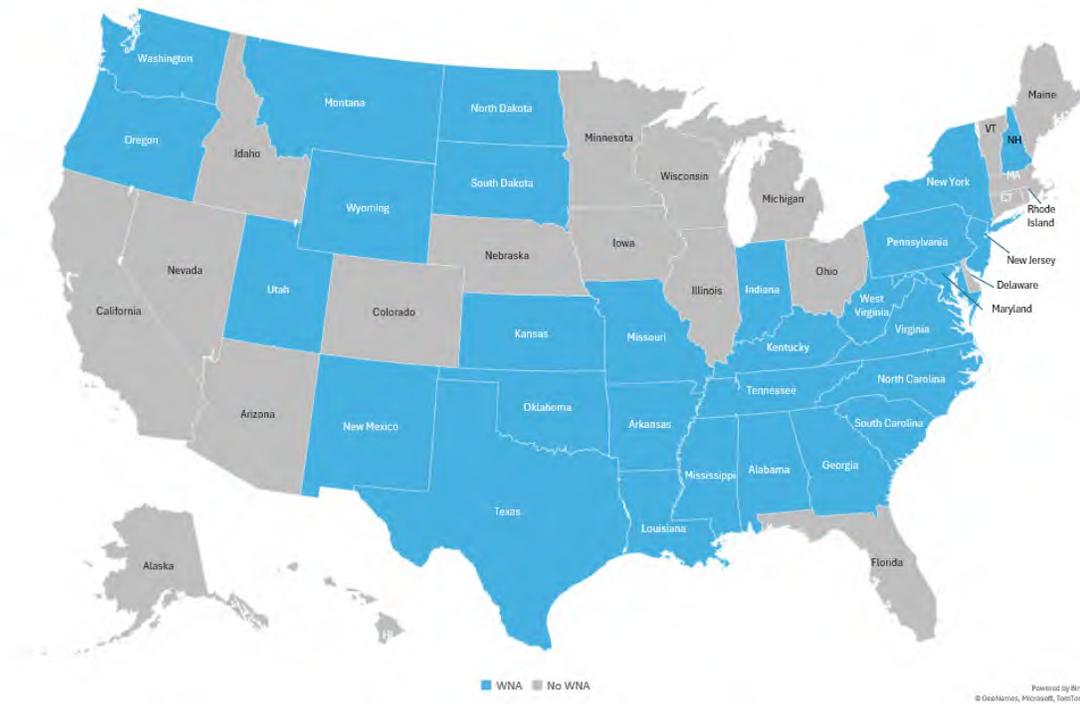
10 **Q. Are WNAs common alternative ratemaking mechanisms in the utility industry?**

11 A. Yes. WNA mechanisms are widely used across the United States to stabilize customer
12 bills and utility revenues during weather conditions that deviate from normal. The map
13 that follows shows that 29 states with a total of 67 gas utilities have adopted similar
14 mechanisms.

¹⁴ “the Commission may consider, among other relevant factors, the following:” Docket M-2015-2518883 PA Bulletin Dated July 1, 2020 (<https://www.puc.pa.gov/pcdocs/1633016.pdf>)

1

Figure 1 – WNA in the United States



2

3

4 **Q. Why should the Commission approve the continuation of UGI Gas’s WNA pilot?**

5 A. The continuation of UGI Gas’s WNA pilot is reasonable because it supports the
6 Company’s ability to recover its Commission-authorized revenue requirement, which is
7 based on prudently planned, just and reasonable costs incurred to provide safe and reliable
8 service. In its most recent decision in Columbia’s case, issued on December 2025, the
9 Commission has recognized the role of weather normalization mechanisms in addressing
10 weather-related revenue volatility by allowing the continuation of Columbia’s WNA pilot.
11 Further, as designed, the Company has already taken into consideration and adopted many
12 modifications intended to provide greater transparency and more protections to customers,

1 as well as reasonable limitations previously supported by the parties and the Commission.
2 For these reasons, UGI Gas's proposed WNA should be approved as filed.

3

4 **VIII. CONCLUSION**

5 **Q. Please summarize your conclusions and recommendations for UGI Gas's ACOSS,**
6 **class revenues, and rate design.**

7 A. I recommend that the Commission approve the following:

- 8 • The Company's proposed ACOSS, as a realistic reflection of cost causation and the
9 design and operating characteristics of the Company's distribution system, and as a
10 guide to evaluate and set UGI Gas's class revenues and rate design in this proceeding.
- 11 • The Company's proposed apportionment of revenues to its rate classes, because it
12 reasonably balances the various criteria that the Company considered in the revenue
13 apportionment process and moves classes towards their cost to serve.
- 14 • The rate design proposed by the Company, including the proposed customer charge
15 increases, because it reasonably balances key rate design objectives I presented earlier
16 in my testimony, including: (1) achieving fair and equitable rate levels that are
17 reflective of the cost to serve; (2) avoiding undue discrimination between and within
18 rate classes; (3) developing rates that are stable and understandable; (4) creating
19 economically efficient pricing for delivery service; (5) encouraging conservation and
20 efficient use; and (6) recovering the revenue requirement in a manner that maintains
21 revenue stability and minimizes year-to-year under- or over-collections.
- 22 • The Company's proposal to extend the WNA pilot program through October 2032,
23 along with alignment in the use of a 10-year period for defining normal weather for

1 the WNA, sales and billing determinants in this case, which address weather-driven
2 revenue fluctuations, as the alternative ratemaking mechanism to recovering
3 distribution fixed costs through a fixed charge.

4

5 **Q. Does this conclude your direct testimony?**

6 **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

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board
- Public Service Commission of West Virginia

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.



UGI GAS

EXHIBIT JDT-2

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
Normal Heating Degree Days Report

Normal Heating Degree Days (“NHDDs”) Report and Recommendation

This report and recommendation was prepared in compliance with item D.58.e of the Settlement Agreement in Docket Nos. R-2024-3052716, et al., which established the following:

(...) UGI Gas will include in its filing a report and recommendation on the use of a rolling ten-year historical average period to be used to calculate its normal heating degree day amounts for purposes of the WNA, as well as the use of a ten-year historical average period for purposes of determining projected sales and billing determinants in base rates.

I. Use of a ten-year historical average NHDD for base-rate billing determinants

Based on the analysis prepared by Atrium Economics of historic HDD data from 1975–2024, shown in Figure 1,¹ adopting a ten-year historical average is recommended. The long-term regression line demonstrates a persistent downward trend in HDDs, reflecting a period of ongoing warming over the last several decades, and provides useful directional context for evaluating normalization alternatives. Compared with 15-year average normals from two different recent periods (2005–2019² and 2010–2024) utilized by UGI Gas, the 10-year normal (2015–2024) more closely aligns with the current climate trajectory and the most recent observed weather patterns. Importantly, the 10-year historical average produces results that are closely aligned with the central tendency implied by the regression trend.

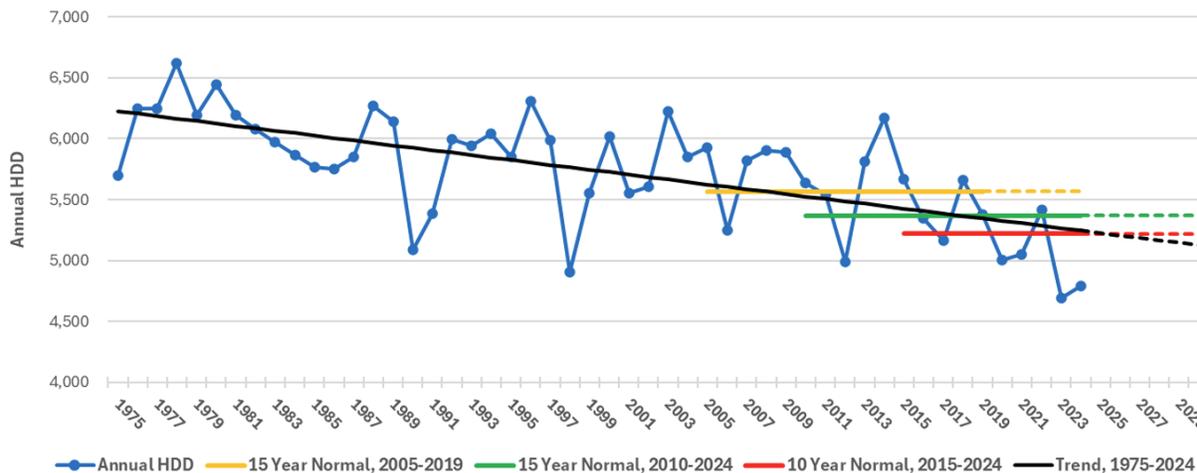
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¹ Based on the composite average for the UGI Gas distribution system which is calculated as the weighted average of HDD data for the following weather stations: Wilkes-Barre/Scranton International Airport (KAVP) 22.2%, Bradford Regional Airport (KBFD) 16.3%, Reading Regional Airport (KRDG) 15.2%, Harrisburg International Airport (KMDT) 15.2%, Lancaster Airport (KLNS) 15.2%, Allentown Lehigh Valley International Airport (KABE) 15.2%, and Clearfield–Lawrence Airport (KFIG) 0.7%. The 50-year dataset utilized was obtained from AccuWeather.

² Period used to set NHDDs in the prior rate case for billing determinants as well as initial WNA NHDDs.

UGI Utilities, Inc. – Gas Division
 Before The Pennsylvania Public Utility Commission
 Normal Heating Degree Days Report

Figure 1 – Historic Annual HDD & Normalization Alternatives³



Using a longer period may overstate heating demand and inflate projected sales, leading to normalized usage assumptions that are not reflective of the conditions that customers are likely to experience during the fully projected future projected test year (“FPFTY”) period. Therefore, a ten-year historical normal is more appropriate, more current, and more consistent with the observed trend of warming weather.

II. Use of a rolling ten-year historical average for WNA NHDD

Although the analysis above supports the conclusion that a ten-year average better represents recent warming trends, applying a rolling ten-year average specifically for WNA calculations is not recommended unless the same rolling approach is also used to determine base-rate billing determinants.

If base rates are set using a fixed ten-year normal (e.g., 2015–2024) while WNA calculations later transition to a different rolling ten-year period (e.g., 2016–2025), the WNA would compare actual weather to a baseline inconsistent with the rate-setting baseline. This misalignment could result in over- or under-correction relative to the assumptions embedded in customer rates, which

³ Chart interpretation for grayscale / black-and-white printing:

- Annual HDD values are shown by the solid line with circular markers.
- The trend (1975–2024) is shown by a smooth solid line that slopes downward from left to right.
- The shorter horizontal reference lines near the right side of the chart are explained as follows:
 - The highest horizontal line corresponds to the 15-year normal for 2005–2019.
 - The middle horizontal line corresponds to the 15-year normal for 2010–2024.
 - The lowest horizontal line corresponds to the 10-year normal for 2015–2024.

UGI Utilities, Inc. – Gas Division
Before The Pennsylvania Public Utility Commission
Normal Heating Degree Days Report

is contrary to the WNA's objective of reconciling actual weather to the same normalized weather conditions used in establishing base rates.

Maintaining a consistent HDD baseline for both functions aligns with the overarching utility ratemaking "matching principle," which requires that the utility align revenue requirements and billing determinants within the same period and under the same assumptions when setting rates.⁴ Therefore, rather than using a rolling period or defining a fixed frequency for recalculation, the Company recommends recalculating the NHDD ten-year average based on the most recently completed ten-year period that ended during the historic test year ("HTY"). In this case, that would be the ten-year period ending December 31, 2024.

III. Conclusion

In accordance with item D.58.e of the Settlement Agreement in Docket Nos. R-2024-3052716, et al.:

- It is recommended that the Company adopt a ten-year historical average HDD for determining projected sales and billing determinants in base rates, as the Figure 1 graph clearly demonstrates that a ten-year period reflects recent warming trends and closely tracks the directional signal indicated by the long-term regression analysis making it a reasonable and supportable normalization period.
- It is not recommended to adopt a rolling ten-year historical average for WNA calculations unless the Commission also intends to adopt the use of a rolling period for base-rate normalization between rate cases. Using different normals for rate-setting and WNA reconciliation could introduce inconsistency and unintended outcomes.

This approach maintains methodological integrity, aligns with observed weather trends, and complies with the Settlement's reporting requirements.

⁴ National Regulatory Research Institute, *Future Test Years: Evidence from State Utility Commissions*, Report No. 13-10, at 5 (Oct. 2013), available at <https://pubs.naruc.org/pub/FA86C105-05F5-9766-BC78-29829AC50361>

UGI GAS

EXHIBIT JDT-3

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2022	2022	2023	2023	2023	2023	2023
		NOV	DEC	JAN	FEB	MAR	APR	MAY
R/RT and N/NT	Total Number of Bills	657,848	690,784	702,630	637,189	757,679	644,611	723,767
R/RT and N/NT	Number of Bills with WNA	494,845	335,446	609,400	605,793	709,079	588,357	503,561
R/RT and N/NT	Billed WNA Volume Adj (ccf)	3,349,172	2,246,101	13,453,826	24,268,267	20,479,847	9,423,352	1,105,684
R/RT and N/NT	Billed WNA Revenue Adj (\$)	\$ 1,536,159	\$ 1,021,184	\$ 6,152,516	\$ 10,999,357	\$ 9,194,818	\$ 4,311,784	\$ 487,940
R/RT	Total Number of Bills	591,744	621,058	631,171	573,017	680,249	580,105	650,634
R/RT	Number of Bills with WNA	447,992	301,310	550,669	547,010	639,251	532,148	455,315
R/RT	Billed WNA Volume Adj (ccf)	2,153,568	1,439,549	8,647,924	15,124,980	12,723,261	6,098,146	566,866
R/RT	Billed WNA Revenue Adj (\$)	\$ 1,080,819	\$ 716,506	\$ 4,334,131	\$ 7,543,041	\$ 6,319,132	\$ 3,049,904	\$ 283,485
N/NT	Total Number of Bills	66,104	69,726	71,459	64,172	77,430	64,506	73,133
N/NT	Number of Bills with WNA	46,853	34,136	58,731	58,783	69,828	56,209	48,246
N/NT	Billed WNA Volume Adj (ccf)	1,195,604	806,552	4,805,902	9,143,287	7,756,586	3,325,206	538,818
N/NT	Billed WNA Revenue Adj (\$)	\$ 455,340	\$ 304,678	\$ 1,818,385	\$ 3,456,316	\$ 2,875,687	\$ 1,261,880	\$ 204,455

Data Presented By Calendar Month

Region	Reporting Item	2022	2022	2023	2023	2023	2023	2023
		NOV	DEC	JAN	FEB	MAR	APR	MAY
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	692	987	1,166	998	858	447	181
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	594	982	846	800	791	341	206
UGI Gas - North	Calendar Month - Normal Heating Degree Days	837	1,130	1,313	1,154	1,027	605	303
UGI Gas - North	Calendar Month - Actual Heating Degree Days	725	1,088	1,001	878	942	459	299
UGI Gas - South	Calendar Month - Normal Heating Degree Days	632	905	1,066	911	744	365	130
UGI Gas - South	Calendar Month - Actual Heating Degree Days	555	933	775	701	673	273	129
UGI Gas - West	Calendar Month - Normal Heating Degree Days	781	1,067	1,230	1,056	896	498	220
UGI Gas - West	Calendar Month - Actual Heating Degree Days	712	1,102	948	823	876	423	249

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2022	2022	2023	2023	2023	2023	2023
		NOV	DEC	JAN	FEB	MAR	APR	MAY
R/RT and N/NT	Bill Count Total	661,595	682,807	699,952	639,135	760,059	640,522	722,158
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	495,114	263,607	612,172	607,639	710,022	583,773	246,153
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	74.8%	38.6%	87.5%	95.1%	93.4%	91.1%	34.1%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	21,005	60,755	243	92	531	311	247,613
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	3.2%	8.9%	0.0%	0.0%	0.1%	0.0%	34.3%
R/RT and N/NT	Bill Count without WNA Charges/Credits	145,476	358,445	87,537	31,404	49,506	56,438	228,392
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	22.0%	52.5%	12.5%	4.9%	6.5%	8.8%	31.6%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2023	2023	2023	2023	2023	2023	2023
		JUN	JUL	AUG	SEP	OCT	NOV	DEC
R/RT and N/NT	Total Number of Bills	679,115	672,095	750,421	666,627	712,202	673,107	669,970
R/RT and N/NT	Number of Bills with WNA	5,354	72	5	15	211,543	456,224	460,215
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(18,930)	723	(1,020)	1,221	568,839	2,700,175	4,775,793
R/RT and N/NT	Billed WNA Revenue Adj (\$)	\$ (7,892)	\$ 22	\$ (393)	\$ 454	\$ 258,355	\$ 1,280,999	\$ 2,267,281
R/RT	Total Number of Bills	610,673	604,474	673,177	598,915	640,299	605,796	602,536
R/RT	Number of Bills with WNA	4,668	64	1	14	187,839	412,231	413,761
R/RT	Billed WNA Volume Adj (ccf)	(6,314)	(1,522)	36	(99)	324,373	1,828,070	3,242,561
R/RT	Billed WNA Revenue Adj (\$)	\$ (3,158)	\$ (790)	\$ 10	\$ (50)	\$ 164,836	\$ 946,337	\$ 1,678,848
N/NT	Total Number of Bills	68,442	67,621	77,244	67,712	71,903	67,311	67,434
N/NT	Number of Bills with WNA	686	8	4	1	23,704	43,993	46,454
N/NT	Billed WNA Volume Adj (ccf)	(12,616)	2,245	(1,057)	1,320	244,467	872,105	1,533,232
N/NT	Billed WNA Revenue Adj (\$)	\$ (4,735)	\$ 812	\$ (402)	\$ 504	\$ 93,519	\$ 334,662	\$ 588,432

Data Presented By Calendar Month

Region	Reporting Item	2023	2023	2023	2023	2023	2023	2023
		JUN	JUL	AUG	SEP	OCT	NOV	DEC
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	35	3	10	96	376	692	987
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	51	0	5	107	320	724	786
UGI Gas - North	Calendar Month - Normal Heating Degree Days	104	42	65	202	523	837	1,130
UGI Gas - North	Calendar Month - Actual Heating Degree Days	111	8	32	159	407	773	843
UGI Gas - South	Calendar Month - Normal Heating Degree Days	11	0	2	54	306	632	905
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	0	0	47	261	647	728
UGI Gas - West	Calendar Month - Normal Heating Degree Days	54	13	26	147	453	781	1,067
UGI Gas - West	Calendar Month - Actual Heating Degree Days	80	1	18	144	408	691	763

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2023	2023	2023	2023	2023	2023	2023
		JUN	JUL	AUG	SEP	OCT	NOV	DEC
R/RT and N/NT	Bill Count Total	0	0	0	0	727,098	668,042	663,445
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	0	0	184,540	431,193	470,364
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	25.4%	64.5%	70.9%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	0	0	55,602	7,234	3,747
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	7.6%	1.1%	0.6%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	0	0	486,956	229,615	189,334
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	0.0%	0.0%	67.0%	34.4%	28.5%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024	2024	2024	2024	2024	2024	2024
		JAN	FEB	MAR	APR	MAY	JUN	JUL
R/RT and N/NT	Total Number of Bills	724,592	681,980	682,512	725,300	721,146	679,265	734,574
R/RT and N/NT	Number of Bills with WNA	681,099	645,482	646,595	664,738	586,262	30,534	499
R/RT and N/NT	Billed WNA Volume Adj (ccf)	17,463,903	19,299,656	25,201,442	10,508,920	6,187,180	451,727	(15,683)
R/RT and N/NT	Billed WNA Revenue Adj (\$)	\$ 8,167,157	\$ 9,077,681	\$ 11,847,340	\$ 4,906,085	\$ 2,918,063	\$ 199,054	\$ (6,443)
R/RT	Total Number of Bills	651,291	613,382	613,650	652,736	648,873	611,382	660,330
R/RT	Number of Bills with WNA	614,798	583,134	583,894	601,058	531,639	27,271	314
R/RT	Billed WNA Volume Adj (ccf)	10,942,912	12,481,667	16,251,546	6,519,900	4,057,503	191,750	(2,927)
R/RT	Billed WNA Revenue Adj (\$)	\$ 5,664,520	\$ 6,461,106	\$ 8,412,549	\$ 3,375,181	\$ 2,100,742	\$ 99,280	\$ (1,548)
N/NT	Total Number of Bills	73,301	68,598	68,862	72,564	72,273	67,883	74,244
N/NT	Number of Bills with WNA	66,301	62,348	62,701	63,680	54,623	3,263	185
N/NT	Billed WNA Volume Adj (ccf)	6,520,991	6,817,989	8,949,897	3,989,020	2,129,677	259,977	(12,756)
N/NT	Billed WNA Revenue Adj (\$)	\$ 2,502,636	\$ 2,616,575	\$ 3,434,791	\$ 1,530,905	\$ 817,321	\$ 99,773	\$ (4,895)

Data Presented By Calendar Month

Region	Reporting Item	2024	2024	2024	2024	2024	2024	2024
		JAN	FEB	MAR	APR	MAY	JUN	JUL
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	1,166	1,031	858	447	181	35	3
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	1,026	860	648	378	111	8	0
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,313	1,193	1,027	605	303	104	42
UGI Gas - North	Calendar Month - Actual Heating Degree Days	1,133	920	754	474	157	56	8
UGI Gas - South	Calendar Month - Normal Heating Degree Days	1,066	941	744	365	130	11	0
UGI Gas - South	Calendar Month - Actual Heating Degree Days	944	771	559	304	82	1	0
UGI Gas - West	Calendar Month - Normal Heating Degree Days	1,230	1,091	896	498	220	54	13
UGI Gas - West	Calendar Month - Actual Heating Degree Days	1,052	879	675	420	141	36	2

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024	2024	2024	2024	2024	2024	2024
		JAN	FEB	MAR	APR	MAY	JUN	JUL
R/RT and N/NT	Bill Count Total	731,791	680,203	676,080	730,279	728,083	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	688,451	643,676	639,931	666,340	587,492	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	94.1%	94.6%	94.7%	91.2%	80.7%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	508	3	369	899	175	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	42,832	36,524	35,780	63,040	140,416	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	5.9%	5.4%	5.3%	8.6%	19.3%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2024	2024	2024	2024	2024	2025	2025
		AUG	SEP	OCT	NOV	DEC	JAN	FEB
R/RT and N/NT	Total Number of Bills	728,175	669,948	751,839	652,863	690,188	742,545	647,127
R/RT and N/NT	Number of Bills with WNA	128	(2)	288,385	559,418	427,644	415,714	426,511
R/RT and N/NT	Billed WNA Volume Adj (ccf)	(6,104)	(4,027)	1,723,324	8,405,258	2,957,527	(3,100,199)	(3,255,501)
R/RT and N/NT	Billed WNA Revenue Adj (\$)	\$ (2,527)	\$ (1,704)	\$ 795,006	\$ 3,968,165	\$ 1,388,659	\$ (1,431,770)	\$ (1,513,534)
R/RT	Total Number of Bills	653,863	603,292	674,662	588,776	621,163	667,793	582,802
R/RT	Number of Bills with WNA	39	(4)	259,212	508,986	385,192	373,211	384,270
R/RT	Billed WNA Volume Adj (ccf)	(1,295)	(1,207)	996,923	5,538,982	1,887,330	(1,812,212)	(1,975,349)
R/RT	Billed WNA Revenue Adj (\$)	\$ (675)	\$ (621)	\$ 516,234	\$ 2,868,153	\$ 977,916	\$ (937,443)	\$ (1,022,233)
N/NT	Total Number of Bills	74,312	66,656	77,177	64,087	69,025	74,752	64,325
N/NT	Number of Bills with WNA	89	2	29,173	50,432	42,452	42,503	42,241
N/NT	Billed WNA Volume Adj (ccf)	(4,809)	(2,820)	726,400	2,866,276	1,070,197	(1,287,987)	(1,280,152)
N/NT	Billed WNA Revenue Adj (\$)	\$ (1,852)	\$ (1,082)	\$ 278,772	\$ 1,100,013	\$ 410,743	\$ (494,327)	\$ (491,302)

Data Presented By Calendar Month

Region	Reporting Item	2024	2024	2024	2024	2024	2025	2025
		AUG	SEP	OCT	NOV	DEC	JAN	FEB
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	10	96	376	692	987	1,166	998
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	19	48	315	627	1,030	1,266	999
UGI Gas - North	Calendar Month - Normal Heating Degree Days	65	202	523	837	1,130	1,313	1,154
UGI Gas - North	Calendar Month - Actual Heating Degree Days	43	79	406	681	1,061	1,364	1,103
UGI Gas - South	Calendar Month - Normal Heating Degree Days	2	54	306	632	905	1,066	911
UGI Gas - South	Calendar Month - Actual Heating Degree Days	6	25	244	516	912	1,173	891
UGI Gas - West	Calendar Month - Normal Heating Degree Days	26	147	453	781	1,067	1,230	1,056
UGI Gas - West	Calendar Month - Actual Heating Degree Days	25	74	388	655	1,021	1,310	1,019

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2024	2024	2024	2024	2024	2025	2025
		AUG	SEP	OCT	NOV	DEC	JAN	FEB
R/RT and N/NT	Bill Count Total	0	0	766,628	629,649	703,828	730,792	653,438
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	0	0	323,925	546,068	319,684	32,920	22,900
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	0.0%	0.0%	42.3%	86.7%	45.4%	4.5%	3.5%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	0	0	1,074	38	107,240	386,799	388,472
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.0%	0.1%	0.0%	15.2%	52.9%	59.5%
R/RT and N/NT	Bill Count without WNA Charges/Credits	0	0	441,629	83,543	276,904	311,073	242,066
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	0.0%	0.0%	57.6%	13.3%	39.3%	42.6%	37.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025	2025	2025	2025	2025	2025	2025
		MAR	APR	MAY	JUN	JUL	AUG	SEP
R/RT and N/NT	Total Number of Bills	716,321	709,895	709,872	713,760	735,660	705,888	701,197
R/RT and N/NT	Number of Bills with WNA	522,521	637,555	484,433	19,813	57	18	(25)
R/RT and N/NT	Billed WNA Volume Adj (ccf)	9,366,210	12,277,590	6,286,389	45,793	(12,712)	(2,385)	(3,696)
R/RT and N/NT	Billed WNA Revenue Adj (\$)	\$ 4,406,295	\$ 5,750,700	\$ 2,950,691	\$ 21,098	\$ (5,680)	\$ (1,002)	\$ (1,347)
R/RT	Total Number of Bills	644,559	639,457	638,553	642,608	661,589	635,194	631,059
R/RT	Number of Bills with WNA	470,537	576,765	439,236	17,805	9	18	(20)
R/RT	Billed WNA Volume Adj (ccf)	6,060,757	7,757,939	4,018,315	20,549	(10,066)	(1,113)	(2,077)
R/RT	Billed WNA Revenue Adj (\$)	\$ 3,137,726	\$ 4,016,147	\$ 2,080,248	\$ 11,410	\$ (4,836)	\$ (514)	\$ (1,075)
N/NT	Total Number of Bills	71,762	70,438	71,319	71,152	74,071	70,694	70,138
N/NT	Number of Bills with WNA	51,984	60,790	45,197	2,008	48	-	(5)
N/NT	Billed WNA Volume Adj (ccf)	3,305,453	4,519,651	2,268,074	25,244	(2,646)	(1,272)	(1,619)
N/NT	Billed WNA Revenue Adj (\$)	\$ 1,268,569	\$ 1,734,552	\$ 870,443	\$ 9,688	\$ (844)	\$ (488)	\$ (272)

Data Presented By Calendar Month

Region	Reporting Item	2025	2025	2025	2025	2025	2025	2025
		MAR	APR	MAY	JUN	JUL	AUG	SEP
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	858	447	181	35	3	10	96
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	667	425	219	31	3	43	38
UGI Gas - North	Calendar Month - Normal Heating Degree Days	1,027	605	303	104	42	65	202
UGI Gas - North	Calendar Month - Actual Heating Degree Days	748	496	318	61	18	116	175
UGI Gas - South	Calendar Month - Normal Heating Degree Days	744	365	130	11	0	2	54
UGI Gas - South	Calendar Month - Actual Heating Degree Days	553	318	114	15	0	11	8
UGI Gas - West	Calendar Month - Normal Heating Degree Days	896	498	220	54	13	26	147
UGI Gas - West	Calendar Month - Actual Heating Degree Days	698	464	268	39	1	65	87

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025	2025	2025	2025	2025	2025	2025
		MAR	APR	MAY	JUN	JUL	AUG	SEP
R/RT and N/NT	Bill Count Total	709,220	714,780	708,205	0	0	0	0
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	535,815	638,314	465,363	0	0	0	0
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	75.5%	89.3%	65.7%	0.0%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	26	2,067	8,174	0	0	0	0
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	0.0%	0.3%	1.2%	0.0%	0.0%	0.0%	0.0%
R/RT and N/NT	Bill Count without WNA Charges/Credits	173,379	74,399	234,668	0	0	0	0
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	24.4%	10.4%	33.1%	0.0%	0.0%	0.0%	0.0%

UGI Utilities, Inc. - Gas Division
Weather Normalization Adjustment Pilot Reporting

Data Presented by Month Revenue Billed and Recorded

Rate Schedules	Reporting Item	2025 OCT
R/RT and N/NT	Total Number of Bills	762,059
R/RT and N/NT	Number of Bills with WNA	281,147
R/RT and N/NT	Billed WNA Volume Adj (ccf)	803,710
R/RT and N/NT	Billed WNA Revenue Adj (\$)	\$ 374,502
R/RT	Total Number of Bills	684,790
R/RT	Number of Bills with WNA	253,447
R/RT	Billed WNA Volume Adj (ccf)	497,914
R/RT	Billed WNA Revenue Adj (\$)	\$ 257,422
N/NT	Total Number of Bills	77,269
N/NT	Number of Bills with WNA	27,700
N/NT	Billed WNA Volume Adj (ccf)	305,796
N/NT	Billed WNA Revenue Adj (\$)	\$ 117,080

Data Presented By Calendar Month

Region	Reporting Item	2025 OCT
UGI Gas - Central	Calendar Month - Normal Heating Degree Days	341
UGI Gas - Central	Calendar Month - Actual Heating Degree Days	398
UGI Gas - North	Calendar Month - Normal Heating Degree Days	473
UGI Gas - North	Calendar Month - Actual Heating Degree Days	530
UGI Gas - South	Calendar Month - Normal Heating Degree Days	279
UGI Gas - South	Calendar Month - Actual Heating Degree Days	309
UGI Gas - West	Calendar Month - Normal Heating Degree Days	429
UGI Gas - West	Calendar Month - Actual Heating Degree Days	469

Data Presented By Ending Month of Billing Period

Rate Schedules	Reporting Item	2025 OCT
R/RT and N/NT	Bill Count Total	770,361
R/RT and N/NT	Bill Count with WNA Charges (upward adjustments)	225,621
R/RT and N/NT	Bill Count with WNA Charges as % of Bill Count Total	29.3%
R/RT and N/NT	Bill Count with WNA Credits (downward adjustments)	83,898
R/RT and N/NT	Bill Count with WNA Credits as % of Bill Count Total	10.9%
R/RT and N/NT	Bill Count without WNA Charges/Credits	460,842
R/RT and N/NT	Bill Count without WNA Charges/Credits as % of Bill Count Total	59.8%

UGI GAS

EXHIBIT JDT-4

UGI Utilities, Inc. – Gas Division
 Before The Pennsylvania Public Utility Commission
 WNA Mechanism Policy Factors

#	Statement of Policy	Company’s Response
1	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	UGI Gas’s WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. The Company recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of a rate design that affords the Company the opportunity to recover all fixed costs in a fixed monthly charge, the WNA mechanism better aligns distribution revenues with cost causation principles.
2	How the ratemaking mechanism and rate design impact the fixed utility’s capacity utilization.	While the WNA mechanism does not directly alter customer usage patterns or system peak demand, it plays an important enabling role in the efficient utilization of the Company’s gas distribution capacity. Gas system capacity is designed to meet peak-day requirements driven by weather-sensitive load. Traditional volumetric recovery exposes the Company to revenue volatility when conservation, or efficiency efforts reduce throughput, even though peak-driven infrastructure costs remain largely unchanged. By stabilizing revenues, the WNA mechanism removes disincentives to support peak-reflective rate design and conservation initiatives that can moderate peak demand growth. Over time, this alignment supports more efficient use of existing system capacity while preserving the Company’s ability to make prudent investments necessary to maintain safe and reliable service.
3	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the	Customer specific usage factors corresponding to their individual demand is continually updated through the WNA formula and reflects the level of demand associated with the customer’s anticipated consumption levels. In this proceeding, the Company is also proposing to set Normal Heating Degree Days using a 10-year

UGI Utilities, Inc. – Gas Division
 Before The Pennsylvania Public Utility Commission
 WNA Mechanism Policy Factors

#	Statement of Policy	Company's Response
	customer's anticipated consumption levels.	average rather than a 15-year average, which more accurately captures recent warming trends. Using a more current weather baseline ensures that the WNA formula better aligns normalized usage with customers' anticipated consumption levels under today's climate conditions. Please refer to UGI Gas Exhibit JDT-2.
4	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	UGI Gas's WNA is applied on a customer-specific basis and is designed to be revenue-neutral within each customer class, such that it does not create or exacerbate cross-subsidization either within or across classes.
5	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.
6	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Customers retain strong incentives to reduce usage because the commodity and other charges remain volumetric. The proposed WNA does not eliminate these price signals, so lower usage still results in lower bills.
7	How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.	In accordance with the Settlement Agreement in Docket Nos. R-2024-3052716, et al., the current WNA mechanism does not apply to low-income customers enrolled in the Company's Customer Assistance Program ("CAP").
8	How the ratemaking mechanism and rate design impact customer rate stability principles.	The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states: "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are

UGI Utilities, Inc. – Gas Division
 Before The Pennsylvania Public Utility Commission
 WNA Mechanism Policy Factors

#	Statement of Policy	Company’s Response
		<p>called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers’ operation are minimized.” The WNA mechanism provides customers with more stable annual bills and directly mitigates volatility in their monthly costs. Customers would pay for the costs assigned to the volumetric base rate in the most recent rate case and customers would not pay more or less than that amount (outside of any established WNA deadband) solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the volumetric base rate.</p>
9	<p>How weather impacts utility revenue under the ratemaking mechanism and rate design.</p>	<p>The Company’s WNA adjusts customers’ bills due to variations from normal weather during the heating season months of October through April, and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of any established deadband). It only applies to certain of the Company’s customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.</p>
10	<p>How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.</p>	<p>The WNA does not impact the Company’s rate case frequency nor it effects regulatory lag.</p>
11	<p>If or how the ratemaking mechanism and rate design interact with other revenue sources (e.g., surcharges).</p>	<p>The Company’s proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through April. Specifically, the billing for the Company’s Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.</p>

UGI Utilities, Inc. – Gas Division
 Before The Pennsylvania Public Utility Commission
 WNA Mechanism Policy Factors

#	Statement of Policy	Company’s Response
12	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	<p>UGI Gas’s WNA includes several consumer protections to ensure fairness and transparency, as follows:</p> <ul style="list-style-type: none"> a. No Over-Recovery of Revenue: The WNA mechanism operates with a deadband and outside of the deadband the WNA results in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. b. No Cross-Subsidization: The WNA is customer-specific. c. Regulatory Oversight: The WNA is subject to Commission review and regulatory reporting requirements to ensure compliance with approved revenue stabilization objectives and to protect consumers from unintended rate impacts. d. Customer Transparency and Education: UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.
13	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	<p>The WNA is not a new concept to the regulated utility industry and similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. The WNA tariff provides detailed information to the customer of how the mechanism would work and the adjustments are displayed separately on bills and the Company maintains a detailed FAQ related to the WNA on its website, ensuring transparency. As indicated above, UGI Gas has reviewed the WNA Pilot communication materials, and it has expanded its reporting as agreed upon in Docket No. R-2024-3052716 settlement. Please refer to the direct testimony of Company witness Meilinger, UGI Gas Statement No. 12, for details.</p>
14	How the ratemaking mechanism and rate design will support improvements in utility reliability.	<p>The proposed WNA targets the revenue requirement that would have been already subject to scrutiny and approved by the Commission, meaning that its prudence and reasonableness would have been reviewed and deemed appropriate to support reliability driven</p>

UGI Utilities, Inc. – Gas Division
 Before The Pennsylvania Public Utility Commission
 WNA Mechanism Policy Factors

#	Statement of Policy	Company's Response
		initiatives. The proposed WNA would help minimize the volatility of the recovery of these costs.

UGI GAS STATEMENT NO. 12

BRIAN J. MEILINGER

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Docket No. R-2025-3059523

UGI Utilities, Inc. – Gas Division

Statement No. 12

**Direct Testimony of
Brian J. Meilinger**

**Topics Addressed: Universal Service Programs
Strategic Initiatives
Low-Income Customer Counts
Weather Normalization Adjustment
("WNA") Communications Revisions**

Dated: January 28, 2026

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Brian J. Meilinger. My business address is 1 UGI Drive, Denver, Pennsylvania
4 17517.

5
6 **Q. By whom are you employed, and what is your current position?**

7 A. I am employed by UGI Utilities, Inc. (“UGI”) as Director, Customer Programs & Public
8 Relations. UGI is a wholly-owned subsidiary of UGI Corporation (“UGI Corp.”). UGI
9 has two operating divisions, the Electric Division (“UGI Electric”) and the Gas Division
10 (“UGI Gas” or the “Company”), each of which is a public utility regulated by the
11 Pennsylvania Public Utility Commission (“Commission” or “PUC”). In this role, I am
12 responsible for directing the Company’s Energy Efficiency & Conservation, Universal
13 Service, Community Relations, and Public Relations Departments.

14
15 **Q. What is your educational and professional background?**

16 A. I graduated from Ursinus College with a B.A. in Economics & Business Administration
17 and Saint Joseph’s University with an MBA in Finance. I started my employment with
18 UGI in 2012. My full resume is attached as UGI Gas Exhibit BJM-1.

19
20 **Q. On whose behalf are you testifying in this proceeding?**

21 A. I am testifying on behalf of UGI Utilities, Inc. – Gas Division (“UGI Gas” or the
22 “Company”).

1 **Q. What is the purpose of your direct testimony?**

2 A. The purpose of my direct testimony is to explain the significant efforts that UGI Gas has
3 undertaken to make sure that its customers have access to affordable utility service.
4 Customer affordability is a core focus at UGI Gas. This is evident from the success of the
5 Company's many customer programs, as well as the Company's commitment to
6 voluntarily donate \$1 million annually per year for the next three years (FY27, FY28, and
7 FY29) to Operation Share. I will discuss these efforts in greater detail below.

8

9 **Q. How is your direct testimony organized?**

10 A. My direct testimony (1) describes how UGI's Universal Service Programs have helped
11 customers afford their utility bills, (2) provides an overview of strategic initiatives to drive
12 increased customer participation in Universal Service Programs and address customer
13 affordability concerns, including the Company's commitment to donate \$1 million
14 annually to Operation Share for the next three years; (3) provides data regarding the
15 Company's low-income customer counts, and (4) addresses the Company's compliance
16 with paragraph 58(a) of the Joint Petition for Approval of Settlement of All Issues at
17 Docket No. R-2024-3052716 ("2025 Settlement") regarding Weather Normalization
18 Adjustment ("WNA") pilot communications.

19

20 **Q. Are you sponsoring any exhibits with your direct testimony?**

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

1 **II. UNIVERSAL SERVICE PROGRAMS**

2 **Q. Does UGI Gas have a Universal Service and Energy Conservation Program**
3 **(“USECP”)?**

4 A. Yes. The USECP is a comprehensive plan that covers the Company’s universal service
5 programs. In accordance with the Commission’s Universal Service and Energy
6 Conservation Reporting Requirements at 52 Pa. Code §§ 54.71 – 54.78 and §§ 62.1 – 62.8,
7 UGI Gas submits a USECP every five years for the Commission’s review and approval.

8
9 **Q. Did UGI Gas recently file its USECP for the five-year period January 1, 2026, through**
10 **December 31, 2030?**

11 A. Yes. The Company filed its 2026-2030 USECP on April 1, 2025, at Docket Nos. M-2025-
12 3054362 and M-2025-3054366. The parties submitted comments on October 6, 2025, and
13 reply comments on November 10, 2025.

14
15 **Q. Is UGI Gas proposing any changes to its USECP as a part of this base rate**
16 **proceeding?**

17 A. No. However, UGI Gas intends to update its USECP with the \$1 million donation to
18 Operation Share through 2029 as described in my testimony.

19
20 **Q. Can you please provide an overview of the Company’s USECP?**

21 A. The Company offers four programs under its USECP that assist low income customers: (1)
22 Customer Assistance Program (“CAP”); (2) the Hardship Fund (i.e., Operation Share); (3)
23 Low Income Usage Reduction Program (“LIURP”); and (4) the Customer Assistance
24 Referral and Evaluation Services (“CARES”).

1 CAP provides discounted monthly bills and arrearage forgiveness for low-income
2 customers at or below 150% Federal Poverty Income Guidelines (“FPIG”). CAP payments
3 are calculated based on a percentage of a customer’s monthly income, also known as a
4 Percentage of Income (“PIP”) amount, or a CAP participant’s average monthly bill, if
5 lower. For gas heating customers, maximum monthly CAP payments are set at 4% of
6 income for customers with household incomes between 0-50%, and 6% of income for
7 customers with household incomes between 51-150% FPIG. CAP participants with no
8 income are placed on the monthly minimum payment which is \$25 for gas heating and \$15
9 for non-heating gas service.

10 Operation Share provides grants of up to \$600 for eligible customers with
11 household incomes up to 250% FPIG who are having difficulty paying their bill. In special
12 circumstances, the Company may provide exceptions to the maximum grant amount of
13 \$600. In order to qualify for a grant, the following criteria must be met:

- 14 • Customer must have a residential account with their premise being the customer’s
15 primary residence;
- 16 • The customer must have an active heating or non-heating account;
- 17 • A customer must not have received the maximum Operation Share grant amount in the
18 prior 12 months, unless in situations of special circumstance as determined by the
19 Company;
- 20 • A customer must have an outstanding balance;
- 21 • A customer must provide proof of identification and adequate information to
22 demonstrate the inability to pay their bill;
- 23 • Customers whose service has been terminated must contact the UGI Credit Department
24 to discuss their options as Community Based Organizations (“CBOs”) cannot provide
25 benefits on an inactive account.

26 The Company’s LIURP offers weatherization services to low-income customers
27 with household incomes up to 200% FPIG. To qualify, a customer must have above

1 average annual usage, defined as exceeding the average residential threshold by 30%, or
2 877 CCF. Additionally, a customer must not have received LIURP in the prior 7 years and
3 must have twelve months of continuous service.

4 CARES offers customers referral services to other community support programs
5 which may include, but are not limited to LIHEAP, budget counseling, State
6 Weatherization, Office of Aging, etc. There are no income requirements to participate in
7 CARES.

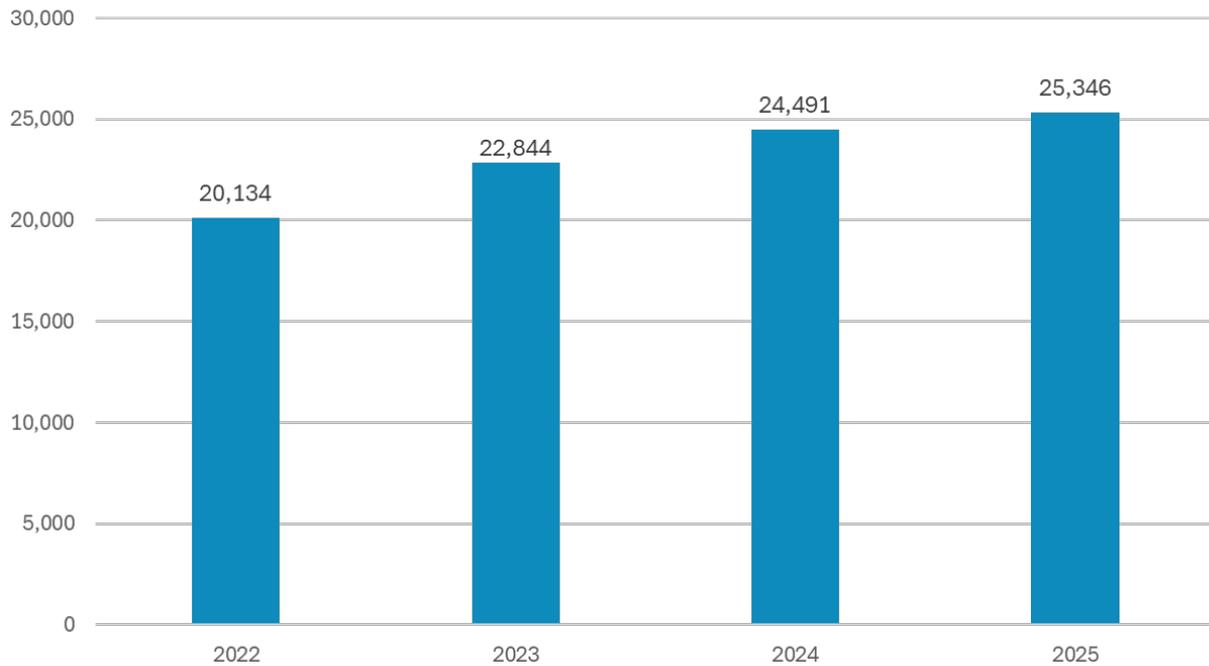
8
9 **Q. Has the Company's CAP helped low-income customers afford their utility bills?**

10 A. Yes. The Company's CAP has performed well both in terms of increasing customer
11 enrollments and helping make customers' bills more affordable.

12
13 **Q. How has the Company's CAP enrollment increased from prior years?**

14 A. The Company's average CAP enrollment for 2025 was 25,346 customers, which represents
15 a 3% increase over 2024, and a 26% increase over 2022 CAP average enrollment of 20,134.
16 Please see Chart 1 below for details regarding the growth in UGI Gas CAP enrollments
17 since 2022.

Chart 1 - Average CAP Enrollments



1

2

The significant growth in CAP enrollments is a direct result of the Company's efforts to reach as many low-income customers as possible. For instance, the Company undertook a project to assess, identify, and engage with low-income customers in 2023-2024. The Company utilized the services of Experian to help identify potential low-income customers and then performed targeted marketing via email and direct mail with a call to action to visit the Company's CAP landing page to screen for program eligibility. This campaign resulted in approximately 780 customers enrolling in CAP.

3

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10 **Q. How has CAP worked to make customers' bills more affordable?**

11 A. In 2024, the Company provided its CAP customers with approximately \$3.8 million of Pre-
12 Program Arrearage ("PPA") forgiveness and \$10.6 million CAP Shortfall and in 2025, \$3.7
13 million and \$15.9 million respectively. The PPA component of CAP is a benefit to
14 customers, as it provides arrearage forgiveness over a 36-month time period if customers

1 continue making timely and in full monthly CAP payments. For instance, a customer
2 entering CAP with \$2,500 of arrearage would have \$69.44 ($\$2,500/36$) forgiven each
3 month assuming the customer continues making monthly CAP payments in full. CAP
4 Shortfall is another significant benefit, as customers are not responsible for monthly costs
5 incurred above the CAP bill. For example, a CAP customer on the Percent of Income Plan
6 with a \$50 per month CAP bill that incurs a usage-based bill calculated at \$150, would not
7 be responsible for the entire bill amount, just the \$50.

8
9 **Q. What are the Company's plans to continue building upon the growth in CAP**
10 **customer enrollments?**

11 A. The Company continues to focus on increasing customer enrollment in CAP through its
12 marketing efforts that include ongoing general outreach efforts throughout the year and
13 twice a year personalized outreach via email and direct mail to customers who are self-
14 certified low income and to LIHEAP recipients that are not currently enrolled in CAP. The
15 Company is also continuing its Low Income Customer Assessment and Outreach Pilot
16 through 2028 as further described in section III below.

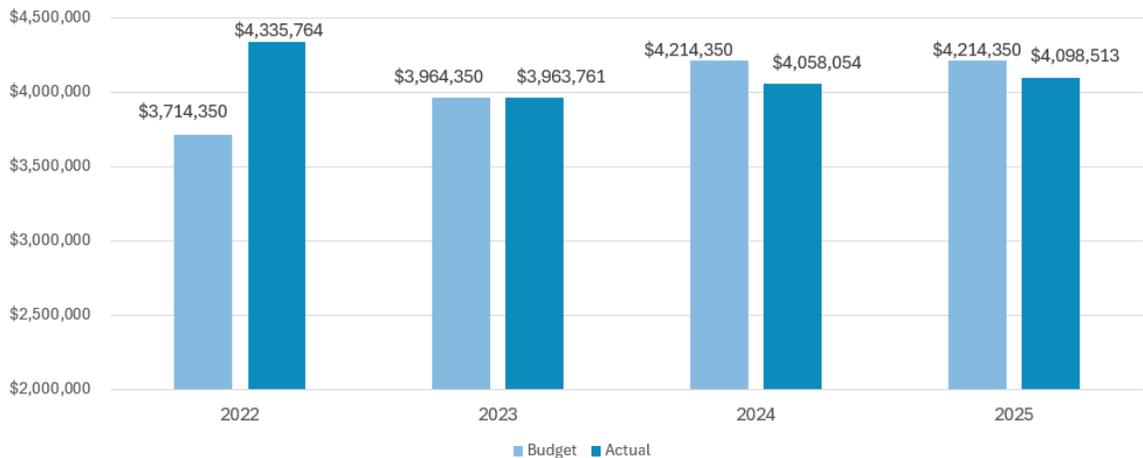
17
18 **Q. How has the Company's LIURP helped customers?**

19 A. The Company has successfully partnered with 15 weatherization CBOs and contractors to
20 maximize its PUC-approved budgets. Since 2022, the following results were achieved
21 which indicate that UGI Gas has been highly effective at achieving spending to budget:

- 22 • 2022: 117% of budget utilization (rollover of unspent budget from prior year)
- 23 • 2023: 100% of budget utilization

- 1 • 2024: 96% of budget utilization
- 2 • 2025: 97% budget utilization

Chart 2 - LIURP Budget vs Actual Spend



3
 4 During the 2022-2025 timeframe, the Company’s weatherization contractors
 5 completed 2,133 LIURP jobs, or an average of 533 per year. As part of the 2025 Settlement,
 6 Paragraph 60(a), the Company has agreed to increase its budget effective January 1, 2026,
 7 by \$1,000,000 from \$4,214,350 to \$5,214,350 with any unspent budget rolling over to the
 8 next year wherein it will make best efforts to spend it within the first six months of the
 9 following year. In addition, UGI Gas will comply with the final order issued in the LIURP
 10 rulemaking proceeding at Docket No. L-2016-2557886.

11
 12 **Q. Has the Company’s Operation Share Program helped customers?**

13 **A.** Yes. During the 2022-2025 timeframe, the Company has issued nearly 12,000 Operation
 14 Share grants for approximately \$4.2 million to customers needing assistance.
 15 Furthermore, as part of the UGI Gas 2025 Settlement, Paragraph 62(a), the Company
 16 increased its Operation Share commitment by \$500,000 from \$584,500 to \$1,084,500 and

1 was permitted to increase the annual budget reallocation limitation across the geographic
2 footprint of its former three rate districts from 5% to 50% (Paragraph 62(b)). Collectively,
3 these settlement provisions provide an increased budget and greater flexibility to reallocate
4 budgets and avoid stranded funding by region, which has occurred in the past.

5
6 **Q. Has UGI Gas undertaken any additional voluntary efforts to support its low-income**
7 **customers?**

8 A. Yes. In November 2025, in an attempt to offset impacts to low-income customers due to
9 LIHEAP funding delays resulting from the Federal Government shutdown, the Company
10 made a one-time supplemental donation of \$500,000, allocated between the Gas and
11 Electric Divisions, to Operation Share for Fiscal Year 2026. I describe the LIHEAP
12 funding delay in greater detail below. This additional donation brought UGI's contribution
13 to Operation Share to more than \$1.5 million for Fiscal Year 2026.

14
15 **Q. Are there other programs available to assist payment-troubled customers?**

16 A. Yes. In addition to the UGI Gas Universal Service Programs, there are external programs
17 to support payment-troubled customers. These state and federally funded programs
18 include, but are not limited to:

- 19 • The Low Income Home Energy Assistance Program (“LIHEAP”) provides energy
20 grants which help customers restore and/or maintain service, as well as repair or replace
21 broken heating equipment. The LIHEAP season typically runs from November 1
22 through April 1. However, in some years, the season is extended pending funding
23 availability. UGI Gas receives a weekly customer voucher file from the Department of
24 Human Services (“DHS”) which contains details of the grant amounts, typically up to
25 a maximum of \$1,000 per customer, who have gone through DHS's income verification
26 processes and are determined to be at or below 150% FPIG. UGI Gas then applies these
27 grant amounts to customer accounts.

- The Pennsylvania Weatherization Assistance Program (“WAP”) reduces energy costs and increases comfort while ensuring homes are healthier and safer. WAP services include a variety of measures that are provided (when necessary) to allow the safe and effective installation of weatherization measures. It also provides client education on the proper use and maintenance of the installed weatherization measures and ways to reduce energy waste. The average expenditure per household is \$7,669 depending on the results of a home audit.¹

Q. How much assistance has LIHEAP provided over the past three seasons?

A. Over the prior three LIHEAP seasons (2022/2023, 2023/2024, 2024/2025) the Company has facilitated approximately 109,000 grants for nearly \$32 million. This funding has been instrumental in assisting low-income customers in maintaining and/or restoring natural gas service as well as emergency furnace repair or replacement. For the 2025-2026 LIHEAP season that had a delayed start date of early December, the Company has already facilitated the processing of approximately 10,106 grants for \$2.6 million.

Q. What actions did the Company take to help offset the customer impacts that could have resulted from the delay in LIHEAP launching for the 2025/2026 season?

A. In addition to the proactive \$500,000 supplemental Operation Share Company contribution mentioned earlier, the Company’s efforts described below were designed to provide additional assistance to customers and minimize terminations during the delay in LIHEAP funding until the program resumed in December 2025.

Active Income Verified Low-Income Customers (150% FPIG):

- Effective November 1, 2025, UGI temporarily suspended field terminations for non-payment for CAP customers. The Company also worked to maximize any available Operation Share grants to assist with arrears. If an Operation Share grant had already been applied during the year, consistent with its USECP, the Company provided a one-time Operation Share grant in excess of the individual

¹ <https://dced.pa.gov/programs/weatherization-assistance-program-wap/>.

1 maximum of \$600 to help maintain the customer's service as active. For this
2 initiative, if a customer was behind in CAP payments totaling \$900 or less, the
3 maximum grant issued was \$900. There were 2,703 Operation Share grants for
4 approximately \$598,000 issued to customers in need during the month of
5 November.

- 6 • Effective November 1, 2025, UGI temporarily suspended field terminations of
7 active customers in arrears who received LIHEAP within the last 12 months and
8 were not enrolled in CAP. The Company continued its Dunning notices during
9 this timeframe to encourage customers to contact the Company and enroll in a
10 Universal Service Program.
 - 11 ○ The Company actively solicited these customers via auto dialer and by
12 email requesting they immediately contact UGI to enroll in CAP to keep
13 service active.
 - 14 ○ For these customers that received LIHEAP in the prior season, they were
15 offered streamlined enrollment into CAP and did not have to provide
16 proof of income to enroll.

17 **Inactive Income Verified Low-Income Customers (150% FPIG &**
18 **Already Terminated for Non-Payment):**

- 19 • For inactive income verified low-income customers (150% FPIG) that contacted
20 the UGI Call Center about their service that had been terminated for non-
21 payment, UGI representatives reviewed options with the customer about
22 enrolling in CAP. If the customer agreed to and was qualified to enroll in CAP,
23 their service was reconnected, and an Operation Share grant was applied to their
24 account. For inactive income verified low-income CAP customers (150% FPIG)
25 that contacted the UGI Call Center about their service that was terminated for non-
26 payment, the Company applied an Operation Share grant to their account to help
27 offset their arrears and turn service back on.

28
29 **Q. What impacts did these actions have in November and December 2025?**

30 A. The success of the Company's efforts during the November and December 2025 timeframe
31 was substantial. Company representatives worked approximately 250 hours of overtime to
32 provide additional assistance to customers who may have been impacted by the
33 Government Shutdown. Highlights are summarized below:

- 1 • 421 confirmed low income customers were enrolled in CAP and either reconnected or
2 not terminated;
- 3 • 3,450 Operation Share grants, totaling \$905,233 were issued in November and
4 December 2025. This can be compared to 332 grants for \$110,201 during this same
5 time period in 2024.

6

7 **III. STRATEGIC INITIATIVES**

8 **Q. What actions has the Company undertaken to maximize customer enrollment in**
9 **Universal Service Programs?**

10 A. As part of the 2025 Settlement, the Company implemented several noteworthy changes to
11 its Universal Service Programs. First, the Company increased its LIURP budget
12 substantially by \$1,000,000 or approximately 24% from \$4,214,350 in calendar year 2025
13 to \$5,214,350 in calendar year 2026. For any unspent LIURP budget, those funds will
14 rollover to the next year to be utilized within the first six months of the following year to
15 the extent possible. Second, the Company substantially increased its Operation Share
16 contribution by \$500,000 or approximately 86% from \$584,500 in Fiscal Year 2025 to
17 \$1,084,500 in Fiscal Year 2026 and added increased flexibility to reallocate program
18 funding from a previous maximum of only 5% to now 50% of funding between the
19 Company’s former rate districts to minimize underspending and to assist customers in
20 need. Third, the Company is undertaking expanded outreach efforts in 2026 through
21 additional in person Winter Assistance Relief Mobilization (“WARM”) events held at
22 targeted locations each year, with a minimum of 6 events in Lancaster, 4 events in Wilkes
23 Barre, and 3 events in Williamsport. Each year thereafter, the Company will target a

1 minimum of three new cities within its service territory as set forth in its tariff, which will
2 be identified in consultation with its Universal Service Advisory Committee. Furthermore,
3 the Company began engaging with various Mayor's offices throughout the UGI Gas
4 service territory to provide the Company's Universal Service brochure in an effort to
5 promote awareness of the Company's low-income assistance programs. Locations for
6 outreach include Allentown, Bethlehem, Easton, Harrisburg, Hazleton, Lancaster, Lock
7 Haven, Pottsville, Reading, Scranton, Wilkes-Barre, and Williamsport. Fourth, the
8 Company is continuing its Low Income Customer Assessment and Outreach Pilot as agreed
9 to in the UGI Gas 2025 Settlement (Paragraph 61(a)) with an annual budget not to exceed
10 \$120,000. The purpose of this Pilot is to engage in additional outreach to the Company's
11 estimated low-income customers up to 150% FPIG identified by third-party consumer
12 credit reporting agency Experian. UGI Gas intends to utilize email, direct mail, and digital
13 ads for targeted marketing to these customers. Customers will be directed to a landing
14 page where they can learn more about the process to pursue enrollment in the Company's
15 CAP. Fifth, UGI Gas has adopted the PUC Common Application Form as of December
16 2025. Finally, the Company has been participating in the DHS data sharing process and
17 has been analyzing this data and evaluating methods to use this information to further
18 promote the availability of the UGI Gas Universal Service Programs. Examples include
19 outreach to data sharing participants who have not yet enrolled in CAP, as well as utilizing
20 the data sharing file to recertify customers for CAP.

1 **Q. What does UGI intend to do to further address affordability concerns for its**
2 **customers?**

3 A. UGI recognizes the importance of supporting the affordability of utility bills for its low-
4 income customers. That is why the Company is committing to contribute \$1,000,000
5 annually to Operation Share in Fiscal Years 2027, 2028, and 2029. This multi-year
6 commitment is unprecedented in the Company's history and will provide substantial
7 assistance to low and moderate income customers with income levels up to 250% FPIG.

8

9 **IV. CONFIRMED LOW-INCOME CUSTOMER COUNTS**

10 **Q. Did UGI previously identify inconsistencies with regulatory reporting of confirmed**
11 **low-income customer counts on prior Universal Service Reports (“USR”)?**

12 A. Yes. During the 2025 UGI Gas Base Rate Case, it was discovered that the Company had
13 inadvertently reported self-certified low-income customers up to 250% FPIG on prior USR
14 filings; however, the Company should have reported only those customers up to 150%
15 FPIG. Therefore, the Company’s confirmed low-income customer counts on prior USR
16 were affected by unintentional data inconsistencies that increased the number of customers
17 included.

18

19 **Q. Has UGI Gas taken steps to ensure that its internal tracking of the “confirmed low-**
20 **income” designation for Universal Service Reporting and USECP purposes has**
21 **become more accurate?**

22 A. Yes. In 2025, the Company made information technology (“IT”) system enhancements to
23 ensure that future Universal Service Reports will include self-certified low-income
24 customers up to 150% FPIG, not 250% FPIG as was previously reported in prior years.

1 This enhancement includes leveraging a more suitable data source, which directly supports
2 the reporting questions being asked. However, significant time and effort to thoroughly vet
3 and cleanse the data was required, which could not be achieved retrospectively. As a result,
4 the 2025 USR confirmed low-income count may result in an overstatement of confirmed
5 low-income counts. The Company anticipates that the confirmed low income counts that
6 will be included on the 2026 Universal Service Report and filed in April 2027, will
7 accurately reflect self-certified low-income customers up to 150% FPIG. Importantly, the
8 Company’s definition of “Confirmed Low Income” is now consistent with the PUC’s
9 regulations at 52 Pa. Code § 62.2, which defines a “confirmed low-income residential
10 account” to include “[a]ccounts where the NGDC has obtained information that would
11 reasonably place the customer in a low-income designation. This information may include
12 receipt of LIHEAP funds, self-certification by the customer, income source or information
13 obtained in § 56.97(b) (relating to procedures upon ratepayer or occupant contact prior to
14 termination).” However, 52 Pa. Code § 62.2 also defines a “low-income customer” as “[a]
15 residential utility customer whose gross household income is at or below 150% of the
16 Federal poverty guidelines. Gross household income does not include the value of food
17 stamps or other noncash income.”²

18
19 **Q. How many confirmed low-income customers does UGI Gas have?**

20 A. As of November 30, 2025, the Company had 68,867 confirmed low-income customers.

21 This figure represents customers who have self-certified their income, participated in the

² <https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter62/s62.2.html&d=reduce>

1 Company's CAP, Operation Share, or LIURP, where income was verified to be at or below
2 150% FPIG, as well as those customers who have received LIHEAP in the prior 12 months.
3 Of the 68,867 Confirmed Low Income customers referenced above, UGI Gas has 38,499
4 customers who have gone through the Company's income verification process, have been
5 verified at or below 150% FPIG, and are eligible to participate in a Universal Service
6 Program.

7 Regarding estimated low-income customers at or below 150% FPIG, as part of the
8 2026-2030 USECP filing supplemental data request³ from the PUC, the Company reported
9 143,404 estimated low-income customers. This figure was developed in accordance with
10 the PUC's Bureau of Consumer Services specified methodology, which derived the
11 estimated number of low income customers by calculating the number of UGI Gas
12 customers in each county of its service territory multiplied by the 2019-2023 American
13 Community Survey 5 Year Estimates census data provided by the Bureau of Consumer
14 Services for that county. However, this calculation methodology may overstate the
15 estimated low-income customer counts due to the census percentages of low-income
16 customers by county which does not necessarily correlate to UGI Gas' customer
17 demographics. By comparison, the Company's Low Income Customer Assessment and
18 Outreach Pilot⁴ undertaken with Experian, identified an estimated low-income population
19 of 98,785 customers at or below 150% FPIG in the fall of 2023. The Experian estimate
20 uses actual demographic income data of UGI customers and identifies significantly less
21 customers, at only 68% of the estimated low income customer count of 143,404.

³ August 25, 2025, response at Docket No. M-2025-3054362

⁴ UGI Gas 2022 Base Rate Case settlement paragraph 46(a).

1 Therefore, UGI Gas's estimated low-income customer counts based on census and
2 published in the USR should be considered an over estimation and referenced with caution.

3
4 **V. WNA COMMUNICATIONS REVISIONS**

5 **Q. Has the Company provided revisions to its communication materials as required in
6 its 2025 Gas Rate Case Settlement?**

7 A. Yes. Consistent with the Settlement requirements, the Company shared draft materials with
8 the required parties, including updates to the Weather Normalization webpage on its public
9 facing website and a new customer letter. The customer letter provides an individualized
10 explanation of charges or credits for a specific billing month. As specified in the 2025
11 Settlement, the Company solicited feedback from interested USAC members and the
12 statutory parties. All edits were consolidated and distributed, with suggestions either
13 incorporated into the materials or feedback provided explaining why they were not
14 included. A final meeting was held with the statutory parties to address any concerns
15 regarding feedback. Approximately twenty website updates were completed in December
16 2025, including creation of a new FAQ page, and seven revisions were made to the
17 customer letter which will be available in fiscal year 2026.

18
19 **VI. CONCLUSION**

20 **Q. Does this conclude your testimony?**

21 A. Yes, it does.

UGI GAS

EXHIBIT BJM-1

Brian J. Meilinger
Director – Customer Programs & Public Relations

Work Experience

UGI Utilities, Inc.

2025 – Present	Director – Customer Programs & Public Relations
2021 – 2025	Sr. Manager – Customer Programs & Community Relations
2015 – 2021	Manager – Energy Efficiency & Conservation Programs
2012 – 2015	Sr. Analyst – Financial Planning & Analysis

Previous Testimony

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2024-3052716

Education

Master of Business Administration in Finance - Saint Joseph's University, Philadelphia, PA
Bachelor of Arts in Economics & Business Administration - Ursinus College, Collegeville, PA