BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

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

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

DOCKET NO. R-2024-3052716

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UGI GAS STATEMENT NO. 6

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 6

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

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

Dated: January 27, 2025

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

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

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

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

Q. What is the purpose of your testimony?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please summarize your cost of equity analysis.

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

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

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

NATURAL GAS RISK FACTORS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. How have you addressed this issue?

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

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

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

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

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

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

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

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

FUNDAMENTAL RISK ANALYSIS

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

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

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

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

Q. What companies comprise the Gas Group?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please summarize your risk evaluation.

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

CAPITAL STRUCTURE RATIOS

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

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

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

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

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

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

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

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

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

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

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

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

COST OF SENIOR CAPITAL

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

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

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

COST OF EQUITY – GENERAL APPROACH

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

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

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

DISCOUNTED CASH FLOW

Q. Please describe the DCF model.

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

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

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

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

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

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

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

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

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

Q. What factors influence investors' growth expectations?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. What is a leverage adjustment?

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

Q. Why is a leverage adjustment necessary?

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

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

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

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

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

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

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

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

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

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

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

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

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

RISK PREMIUM ANALYSIS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Common Equity Risk Premiums

Low Interest Rates	7.13%
Average Across All Interest Rates	5.96%
High Interest Rates	4.76%

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

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

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

The Risk Premium approach provides a cost of equity of:

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

CAPITAL ASSET PRICING MODEL

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

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

Q. What betas have you considered in the CAPM?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. What does your CAPM analysis show?

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

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

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

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

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

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

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

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

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

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach to cover conditions over an entire business cycle. A 10-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.3% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return, as published by Value Line, is 12.5% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data, my Comparable Earnings result is 12.40%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of various methods and models described previously, it is my opinion that the reasonable cost of common equity is 11.20% for the Company that includes recognition of its exemplary management performance. My proposed cost of equity will accommodate the Company's small size and its business risk characteristics. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-one years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water

Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Commission of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

UGI GAS STATEMENT NO. 7

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Darin T. Espigh

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 27, 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Darin T. Espigh. My business address is One UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your principal duties and responsibilities as Senior Manager Natural Gas Tax Accounting for UGI Corp.?

A. My primary duties as Senior Manager Natural Gas Tax Accounting include the preparation of tax data to be reported in UGI Corp.'s various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage the reporting of UGI's various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and professional experience.

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

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2026 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2024 ("HTY") and future test year ending September 30, 2025 ("FTY").

Q. Have you testified previously before this Commission?

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

Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the UGI Gas Exhibits: DTE-1, DTE-2, DTE-3. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related items. These exhibits comprise UGI Gas's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests as indicated on the master list accompanying this filing.

II. TAX ADJUSTMENTS

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY. Section D of UGI Gas Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the HTY and the FTY. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with adjusted actual book results from the HTY and adjusted FTY results. UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31, include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), Pennsylvania and Local Property taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the

Commission, Office of Consumer Advocate and Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2). These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $248,000 is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Gas Exhibit A (Fully Projected), Schedule D-33. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow-through of accelerated depreciation benefits for state tax purposes. UGI Gas is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas continues to flow through the repairs tax benefit over the tax useful lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Gas Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe how Schedule D-33 calculates the Company's claim for income taxes shown on Schedule D-1, lines 19 and 20.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 20. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Schedule D-33, line 1 shows revenue at present and proposed rates, while line 2 shows operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI Gas's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas Statement No. 6) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from operating income before interest and taxes to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9, which appears as ($163,056) on line 10. Next, the statutory state corporate net income tax rate was applied (as further described below in Section F of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Regarding the pro forma federal income tax expense, lines 14 through 19 show the calculation at current and proposed rates. Next, line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates, with the total calculated amount for income taxes, before the application of other adjustments, shown on line 29, which shows the net income tax expense. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Gas?

A. As shown on Schedule D-33 at line 31, the *pro forma* combined income tax expense at present rates is $45.6 million and the *pro forma* tax expense at proposed rates for the FPFTY is $75.2 million. As explained below in Section E, this figure is not required to be reduced by a consolidated income tax adjustment. Moreover, the pro forma income tax at present rates and the pro forma income tax revenue increase calculated in Schedule D-33 appear in Schedule D-1, which comprises the Company's claimed income tax expense.

Q. Has the Company reflected the amortization of Excess Deferred Federal Income Taxes ("EDFIT"), as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"), on its income tax expense claim?

A. Yes, the Company has calculated the amount of the EDFIT that would be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on line 25 of Schedule D-33. The total amortization was approximately $4.3 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT as of September 30, 2026. This amount is deducted from rate base. The total shown on line 9 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was further reduced by the state regulatory liability associated with UGI Gas's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 9 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $687.7 million, which includes the amount related to EDFIT.

Q. Does the Company's reduction to rate base include EDFIT?

A. Yes, the Company has reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 9 of Schedule C-6.

Q. Has the Company's ADIT rate base deduction been calculated in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Gas Exhibit DTE-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

Q. Please explain UGI Gas's accounting treatment of the Repairs Tax Method.

A. In its tax return for the year ended September 30, 2009, UGI Gas adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2021-3030218, UGI Gas chose to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Gas has chosen to flow through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a federal consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes.

A calculation of the consolidated tax adjustment for that purpose, using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40, is included in the Company's filing as Attachment II-A-26 and UGI Gas Exhibit DTE-3. Company witness Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2) discusses how the Company has satisfied the requirements of Act 40.

F. PENNSYLVANIA TAX RATE CHANGE

Q. Are you familiar with the recently enacted Pennsylvania corporate net income tax rate change?

A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which reduced the state corporate net income tax rate from the then-current 9.99% to 4.99% over a nine-year period. The initial reduction to 8.99% was effective for tax years beginning in calendar year 2023. Thus, the initial reduction applied to Fiscal Year End September 30, 2024, which is the Company's HTY.

Q. How has the Company accounted for the recently enacted Pennsylvania tax rate change?

The Company's claim for income taxes reflects the applicable state tax rate in effect for the HTY (i.e., 8.99%), FTY (i.e., 8.49%) and FPFTY (i.e., 7.99%). As explained above, the initial reduction applied to our HTY. The State Tax Adjustment Surcharge ("STAS") mechanism will adjust the Company's rates as applicable for future reductions to the state corporate net income tax rate.

Q. How is the Company applying the Pennsylvania corporate net income tax rate change to its Repairs Tax method?

A. Consistent with historic treatment as described in Section D of this testimony, the Company's state regulatory liability associated with its repairs tax method will continue to represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA ***March 2022 - Present***
Senior Manager of Natural Gas Tax Accounting

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. Supervise 2 direct reports.

JBS USA, Greeley, CO ***2014 – March 2022***
Senior Tax Manager, Tax Accounting and Global Reporting

Manage tax accounting and reporting under ASC 740 including effective rate development, perm development, valuation allowances, ABP 23 indefinite reinvestment assertions, financial statement footnotes, management of global deferred inventory and FIN48/FAS 5 analysis for international consolidated financial statements. Responsible for IFRS adjustments and reporting package to Brazilian parent company. Interface with internal and external auditors. Managed tax accounting aspects of a large global reorganization. Design and streamline provision reporting packages to meet increased demands of public reporting.

Managed both federal and state income tax compliance. Responsible for attribution memos related to the preparation of Form 5472, R&D Credits, Sec 163(j), Schedule G and Schedule O compliance for more than 10 separate federal tax returns. Supervised income tax audits. Managed documentation and notice requirements related to the Foreign Investment in Real Property Tax Act (FIRPTA) related to distributions of U.S. real property interests by foreign corporations. Managed, trained and developed staff in tax accounting and financial reporting and compliance.

UGI UTILITIES, INC., Reading, PA ***2007 to 2014***
Senior Tax Analyst

Responsible for quarterly and annual tax accounting and reporting under ASC 740 including effective rate development, maintenance and classification of deferred inventory balances and account reconciliations. Calculate annual provision to return adjustment for year-end provision. Interface with internal and external auditors on tax related matters. Provide budget and forecast amounts for all tax related items. Preparation of tax data to support external regulatory reporting including Base Rate Case filings.

Preparation of income tax return support submitted to corporate for inclusion in the consolidated income tax return. Responsible for indirect tax compliance.

BERTZ & COMPANY, CPA's, Lancaster, PA ***2000 to 2007***
Senior Associate

Responsible for preparation of individual, corporate, partnership, nonprofit and payroll tax returns. Charged with the preparation of financial statements including required disclosures for a wide range of industries including construction, hospitality and retail food establishments. Supervised, trained and developed staff on client engagements.

Managed audit engagements of retirement plans and homeowner associations. Gained experience on a variety of other audits.

HATTER, HARRIS & BEITTEL, LLP, Lancaster, PA ***1994 to 2000***
Senior Associate

Prepared individual, corporate, partnership, nonprofit and payroll tax returns. Managed review and compilation engagements. Managed nonprofit audit. Developed significant experience in audits of school districts, retail and manufacturing businesses. Gained strong working knowledge of financial statements and related disclosures for engagements of all levels. Trained and developed new staff.

EDUCATION & CREDENTIALS

Bachelor of Science in Accounting – Messiah College, Grantham, PA – May 1994

Certified Public Accountant

Previous Testimony:

UGI Electric Base Rate Case	Docket No. R-2022-3037368

UGI GAS

EXHIBIT DTE-2

UGI Utilities, Inc. - Gas Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2022					$ 675,838
10/31/2022	3,521	335	91.78%	3,231	679,070
11/30/2022	1,087	305	83.56%	909	679,978
12/31/2022	1,425	274	75.07%	1,070	681,048
1/31/2023	721	243	66.58%	480	681,528
2/28/2023	758	215	58.90%	446	681,974
3/31/2023	2,028	184	50.41%	1,023	682,997
4/30/2023	880	154	42.19%	371	683,368
5/31/2023	1,087	123	33.70%	366	683,735
6/30/2023	4,265	93	25.48%	1,087	684,821
7/31/2023	3,097	62	16.99%	526	685,347
8/31/2023	2,187	31	8.49%	186	685,533
9/30/2023	8,903	1	0.27%	24	**$ 685,557**

UGI GAS

EXHIBIT DTE-3

UGI Utilities, Inc. - Gas Division
Calculation of Consolidated Tax Adjustment
For the Years Ended September 30, 2021, 2022 and 2023
In Thousands (000)

	Taxable Income 2021	Taxable Income 2022	Taxable Income 2023	Average	% of Total	CTA
Tax Loss Entities						
AmeriGas Propane Holdings, Inc.	0	0	0	0		
Ashtola Production Company	(1)	(2)	(1)	(1)		
Hellertown Pipeline	0	0	0	0		
Homestead Holding	(76)	(406)	(2,687)	(1,057)		
Mountaineer Gas Company	0		(7,762)	(2,587)		
Mountaintop Energy Holding Inc	0	(29)	(33)	(21)		
UGI Hunlock Dev	0	0	0	0		
UGI HVAC Enterprises	(1,556)	0	0	(519)		
UGI LNG	(3,679)	0	0	(1,226)		
UGID Holding Company	(8)	(5)	(3)	(5)		
Newberry Holding	0	(56)	0	(19)		
United Valley Insurance	0	0	0	0		
UGI Corporation	0	0	(10,953)	(3,651)		
AmeriGas Inc	0	0	0	0		
UGI China Inc	0	0	0	0		
UGI International China. Inc	0	0	0	0		
UGI Penn HVAC Services	0	0	0	0		
UGI Properties, Inc.	0	0	0	0		
UGI Development Company	(4,031)	(1,144)	0	(1,725)		
UGI Enterprises Inc	0	0	0	0		
Subtotal Taxable Loss	**(9,351)**	**(1,642)**	**(21,439)**	**(10,811)**		
Tax Positive Entities						
AmeriGas Propane Inc.	30,085	**30,246**	**25,944**	28,759	7.2%	(774)
AmeriGas Propane Holdings, Inc.	122,728	**136,844**	**123,819**	127,797	31.8%	(3,439)
AmeriGas Inc.	178	**18**		65	0.0%	(2)
Amerigas Technology Group Inc.	0			0	0.0%	0
Energy Service Funding	4,656	**5,385**	**10,721**	6,921	1.7%	(186)
Mountaineer Gas Company	0	**4,636**		1,545	0.4%	(42)
Newberry Holding	120		**35**	52	0.0%	(1)
Petrolane Incorporated	0			0	0.0%	0
UGI China, Inc.	0			0	0.0%	0
UGI Corporation	23,110	**61,904**	**0**	28,338	7.1%	(763)
UGI Development Company	0		**8,658**	2,886	0.7%	(78)
UGI Enterprises, Inc.	0			0	0.0%	0
UGI Europe, Inc.	42,637	70,069	101,886	71,531	17.8%	(1,925)
UGI HVAC Enterprises	0	53		18	0.0%	(0)
UGI LNG	0	4,837	4,402	3,080	0.8%	(83)
UGI Penn HVAC Services	0			0	0.0%	0
UGI Properties, Inc.	438	532	11,716	4,229	1.1%	(114)
UGI Storage Company	4,997	5,138	19,858	9,997	2.5%	(269)
UGI Utilities, Inc.	62,490	105,893	180,897	116,427	29.0%	(3,133)
UGI International Enterprises, Inc.	0			0	0.0%	0
United Valley Insurance	146	97	141	128	0.0%	(3)
Eliminations	0			0	0.0%	0
Subtotal Taxable Income	**291,584**	**425,652**	**488,077**	**401,771**	100.0%	(10,811)
Total Taxable Income	**282,233**	**424,010**	**466,638**	**390,960**		

Tax Savings Applicable to UGI Utilities, Inc.	(3,133)
MWF Allocation % for UGI Gas	89.89%
Total Tax Savings Allocated to UGI Gas	(2,816)
Federal Tax Rate	21%
Total Consolidated Tax Adjustment	**(591)**

Notes:
1. Single-member limited liability companies, i.e. disregarded entities, have been combined with their tax-regarded parent company.

Tax Loss Entities	Taxable Income 2023	Adjustments		Adjusted Taxable Income
UGI Corporation	(156,912)	145,959	(1)	(10,953)
AmeriGas Inc				0
AmeriGas Propane Holdings, Inc.	(153,159)	276,978	(2)	123,819
Amerigas Technology Group Inc.				0
Ashtola Production Company	(1)			(1)
Eastfield International Holdings Inc				0
EuroGas Holdings Inc.				0
Four Flags Drilling Company				0
Hellertown Pipeline				0
Homestead Holding	(2,687)			(2,687)
Mountaineer Gas Company	(7,762)			(7,762)
Mountaintop Energy Holding Inc	(8,511)	8,478	(3)	(33)
Newberry Holding				0
UGI Asset Management				0
UGI Black Sea Enterprises				0
UGI Development Company				0
UGID Holding Company	(3)			(3)
UGI Energy Ventures, Inc.				0
UGI Ethanol Development Company				0
UGI Enterprises Inc				0
UGI Hunlock Dev				0
UGI HVAC Enterprises				0
UGI International China. Inc				0
UGI International (Romania)				0
UGI LNG				0
UGI Penn HVAC Services				0
UGI Petroleum Products of DE				0
UGI Romania, Inc.				0
UGID Holding Company				0
Total Tax Loss	(329,035)	431,415		102,380

Explanations of Adjustments:

(1) Within UGI Corporation there is interest related to the 2019 AmeriGas acquisitio	51,595
UGI Corporation includes it's entire chain of LLC's.Within those LLC's:	
UGI International LLC has hedge losses	6,790
Interest expense related to foreign operations	27,296
UGI PennEast LLC one-time partnership loss due to ceasing business	55,670
Tax Losses in other partnerships - due to Tax > Book Depr in early years.	4,608

(2) Equity pick-up from AmeriGas partnership includes amortization of step-up from acquisition.
Acquisition was in August 2019. Amortization of step up runs 39 years (although most falls off after year 9)

(3) This $8.5 MM is the utilization of a §382 limited NOL that comes into the UGI Corporation consolidated return as the result of the Mountaineer Gas Company acquisition on September 1, 2021.

Tax Loss Entities	Taxable Income 2022	Adjustments		Adjusted Taxable Income
UGI Corporation				0
AmeriGas Inc				0
AmeriGas Propane Holdings, Inc.	(144,954)	281,798	(1)	136,844
Amerigas Technology Group Inc.				0
Ashtola Production Company	(2)			(2)
Eastfield International Holdings Inc				0
EuroGas Holdings Inc.				0
Four Flags Drilling Company				0
Hellertown Pipeline				0
Homestead Holding	(406)			(406)
Mountaineer Gas Company				0
Mountaintop Energy Holding Inc	(8,507)	8,478	(2)	(29)
Newberry Holding	(56)			(56)
UGI Asset Management				0
UGI Black Sea Enterprises				0
UGI Development Company	(1,144)			(1,144)
UGID Holding Company	(5)			(5)
UGI Energy Ventures, Inc.				0
UGI Ethanol Development Company				0
UGI Enterprises Inc				0
UGI Hunlock Dev				0
UGI HVAC Enterprises				0
UGI International China. Inc				0
UGI International (Romania)				0
UGI LNG				0
UGI Penn HVAC Services				0
UGI Petroleum Products of DE				0
UGI Romania, Inc.				0
UGID Holding Company				0
Total Tax Loss	(155,074)	290,276		135,202

Explanations of Adjustments:

(1) Equity pick-up from AmeriGas partnership includes amortization of step-up from acquisition. Acquisition was in August 2019. Amortization of step up runs 39 years (although most falls off after year 9)

(2) This $8.5 MM is the utilization of a §382 limited NOL that comes into the UGI Corporation consolidated return as the result of the Mountaineer Gas Company acquisition on September 1, 2021.

Tax Loss Entities	Taxable Income 2021	Adjustments		Adjusted Taxable Income	(4) Interest Reallocation		Revised Taxable Income
UGI Corporation	(100,191)	54,553	(1)				
		14,384	(5)				
		29,355	(6)	(1,899)	25,009	(4)	23,110
AmeriGas Inc				0			0
AmeriGas Propane Holdings, Inc.	(136,979)	284,717	(2)	147,738	(25,009)	(4)	122,728
Amerigas Technology Group Inc.				0			0
Ashtola Production Company	(1)			(1)			(1)
Eastfield International Holdings Inc				0			0
EuroGas Holdings Inc.				0			0
Four Flags Drilling Company				0			0
Hellertown Pipeline				0			0
Homestead Holding	(76)			(76)			(76)
Mountaineer Gas Company	(4,891)	4,891	(3)	0			0
Mountaintop Energy Holding Inc				0			0
Newberry Holding				0			0
UGI Asset Management				0			0
UGI Black Sea Enterprises				0			0
UGI Development Company	(4,031)			(4,031)			(4,031)
UGID Holding Company	(8)			(8)			(8)
UGI Energy Ventures, Inc.				0			0
UGI Ethanol Development Company				0			0
UGI Enterprises Inc				0			0
UGI Hunlock Dev				0			0
UGI HVAC Enterprises	(1,556)			(1,556)			(1,556)
UGI International China. Inc				0			0
UGI International (Romania)				0			0
UGI LNG	(3,679)			(3,679)			(3,679)
UGI Penn HVAC Services				0			0
UGI Petroleum Products of DE				0			0
UGI Romania, Inc.				0			0
UGID Holding Company				0			0
Total Tax Loss	(251,412)	387,900		136,487	0		136,487

Explanations of Adjustments:

(1) One time bonus depreciation deduction on non-utility fixed assets for a one-time acquisition.
(2) Equity pick-up from AmeriGas partnership includes amortization of step-up from acquisition (a one time event in August 2019).
(3) Mountaineer Gas Company acquired 9/1/2021. Loss is due to only month of activity in September which is a loss month.

(4) Interest Exp on UGI Corp debt related to the Amerigas buyout reallocated to Amerigas.

25,009	Total Interest Exp on Corp
147,738	Amerigas TI Available

(5) Bonus Depr taken to drive NOL carryback. Normally not taken in a loss year.

(6) Back out UGI International loss since foreign earnings not included.

UGI GAS STATEMENT NO. 8

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Sherry A. Epler

Topics Addressed: **Test Year Sales and Revenues**
Tariff Changes

Dated: January 27, 2025

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

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

A. I am employed as Senior Manager, Tariff & Supplier Administration, by UGI Utilities, Inc. ("UGI"). UGI has both a Gas Division ("UGI Gas"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Gas?

A. My current responsibilities related to UGI Gas include: (1) all aspects of tariff and rate administration for UGI Gas, including interactions with natural gas suppliers under UGI Gas's supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background.

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

Q. Please provide your professional experience.

A. I have worked for UGI since 1986, supporting the Accounting and Rates groups in varying capacities. Please see my resume, UGI Gas Exhibit SAE-1, for my full employment history.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2024 ("HTY"), future test year ending September 30, 2025 ("FTY"), and fully projected future test year ending September 30, 2026 ("FPFTY"); and (2) certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness John D. Taylor, who is employed as Managing Partner by Atrium Economics, LLC (UGI Gas Statement No. 10), is sponsoring allocation of revenue increase and rate design, in addition to his testimony supporting class cost of service, using the projected sales and revenue figures discussed in my testimony.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit SAE-1 (Resume), UGI Gas Exhibit SAE-2 (15 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3 (Normalized Multi-Year and Normalized 12-Month Ending Trends of Use Per Customer for Residential and Commercial Heating), UGI Gas Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-7 (Fully Projected Future Test Year, Future Test Year, and Historic Test Year Usage Per Customer Detail by Class), UGI Gas Exhibit SAE-8 (No Notice Service ("NNS") Rate Calculation), UGI Gas Exhibit SAE-9 (Monthly Balancing Service ("MBS") Rate Calculation), UGI Gas Exhibit SAE-10 (Rider D-Merchant Function Charge ("MFC") Calculation), certain portions of UGI Gas Exhibit F

(Proposed Tariff), and UGI Gas Exhibit E (Proof of Revenue). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEAR SALES AND REVENUE

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by incorporating annualizing and normalizing adjustments to the Company's 2026 fiscal year sales and revenue budgets in order to reflect end of FPFTY conditions for ratemaking purposes. The development of the initial sales and revenue budgets which were utilized as the starting point prior to adjustments is described in the testimony of Vivian K. Ressler (UGI Gas Statement No. 3). Where similar adjustments are made across rate class groups, the methodology applied to develop normalized use per customer adjustments (for the FPFTY, FTY, and HTY) to budget values is the same for all three periods in order to present sales and revenue on a comparable ratemaking basis. A summary of projected use per customer by class group for the FPFTY, FTY, and HTY is included in UGI Gas Exhibit SAE-7. The projected Residential Heating use per customer was established for Rate R/RT-Heating per the UGI Gas model detailed in SDR-RR-11. Since, over time, switching occurs on a regular basis between residential Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." Weather normalized sales for Rate RT-Heating customers for the 12 months ended September 30, 2024, were then utilized to mathematically derive the separate Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per customer regression value).

Actual sales were normalized for Rate R-Non-Heating and Rate RT-Non-Heating, in total, for the 12-month period ended September 30, 2024, to eliminate potential switching impacts that could distort use per customer analyses. These data were used to project combined Rate R/RT-Non-Heating use per customer in total. Weather normalized sales for Rate RT-Non-Heating customers for the 12 months ended September 30, 2024, were then utilized to mathematically derive the separate Rate R-Non-Heating customer values (from the combined Rate R/RT-Non-Heating use per customer value).

The projected Commercial Heating use per customer was established on a combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression techniques detailed in SDR-RR-11. Given that, over time, switching occurs on a regular basis between Rates N (retail service), NT (transportation service) and DS (transportation service), the regression analysis was performed on a total Rates N/NT/DS basis to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." To separate the combined Rate N/NT/DS-Commercial Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Heating use per customer was established on the basis of weather normalized sales for Rate NT-Commercial Heating customers, for the 12 months ended September 30, 2024, as this class is much smaller in number than the Rate N-Commercial Heating class. Rate DS-Commercial Heating use per customer was then established based on budgeted 2026 sales for Rate DS-Commercial Heating, as Rate DS budgeting was performed on a detailed per-customer level. These Rate NT and Rate DS

Commercial Heating values were then utilized to mathematically derive the Rate N-Commercial Heating use per customer values (from the combined Rates N/NT/DS-Commercial Heating use per customer value).

Actual sales were normalized for Rate N-Commercial Non-Heating, Rate NT-Commercial Non-Heating and Rate DS-Commercial Non-Heating, in total, to reflect the 12 months ended September 30, 2024, in order to project combined Rates N/NT/DS-Commercial Non-Heating use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined Rate N/NT/DS-Commercial Non-Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT-Commercial Non-Heating was based on weather normalized sales for Rate NT-Commercial Non-Heating, for the 12 months ended September 30, 2024, and Rate DS-Commercial Non-Heating was based on budgeted 2026 sales for Rate DS-Commercial Non-Heating, which were done on a per-customer level. These Rate NT and Rate DS values were then utilized to mathematically derive the Rate N-Commercial Non-Heating use per customer values (from the combined Rates N/NT/DS-Commercial Non-Heating use per customer value).

Actual sales were normalized for Rate N-Industrial, Rate NT-Industrial, and Rate DS-Industrial to reflect the 12 months ended September 30, 2024, in order to project combined Rates N/NT/DS-Industrial use per customer in total and eliminate potential switching impacts that could distort use per customer analyses. To separate the combined Rate N/NT/DS-Industrial value into respective Rate N, Rate NT and Rate DS values, Rate NT-Industrial was based on weather normalized sales for Rate NT-Industrial for the 12 months ended September 30, 2024. Rate DS-Industrial was based on budgeted 2026 sales for Rate DS-Industrial, which were done on a per-customer level. These Rate NT and Rate

DS values were then utilized to mathematically derive the Rate N-Industrial use per customer value (from the combined Rates N/NT/DS-Industrial use per customer value).

Q. How was temperature accounted for in developing sales and revenue forecasts?

A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree days of 5,568. This annual normal heating degree day calculation is derived from a composite sales weighted value (by system demand) for each of the Company's four delivery regions, and the respective normal heating degree values. Normal heating degree days are defined based upon an average over a 15-year period and are updated every five years; the most recent update was for the 15-year period ending December 31, 2019. UGI Gas Exhibit SAE-2 provides supporting detail by year for the 15-year normal heating degree days.

Q. Is the use of average temperature data for a 15-year period consistent with the methodology used for calculating normal heating degree days in previous UGI Gas base rate cases?

A. Yes. The Company has consistently used a 15-year period methodology in the past eight gas base rate cases that the Company or its former subsidiaries have filed (as listed below).

- UGI Central Penn Gas ("CPG") 2009 Base Rate Case, Docket No. R-2008-2079675
- UGI Penn Natural Gas ("PNG") 2009 Base Rate Case, Docket No. R-2008-2079660
- UGI CPG 2011 Base Rate Case, Docket No. R-2010-2214415
- UGI Gas 2016 Base Rate Case, Docket No. R-2015-2518438
- UGI PNG 2017 Base Rate Case, Docket No. R-2016-2580030
- UGI Gas 2019 Base Rate Case, Docket No. R-2018-3006814
- UGI Gas 2020 Base Rate Case, Docket No. R-2019-3015162
- UGI Gas 2022 Base Rate Case, Docket No. R-2022-3030218

Q. Please describe the adjustments made to the budget for the 12 months ending September 30, 2026, to develop FPFTY sales and revenues.

A. A summary of all adjustments made to the 2026 budget in order to develop FPFTY sales and revenue is shown on UGI Gas Exhibit SAE-4(a). Detail for each of these adjustments is provided on subsequent worksheets labeled 4(b) through 4(l). In total, these adjustments reflect an increase to sales of 30 MMcf and an increase to revenue of $17.488 million, inclusive of Purchased Gas Cost ("PGC") revenues.

Q. Please explain the "Adjustment for Customer/Contract Changes" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Customer/Contract Changes" annualizes customer counts to anticipated end-of-test-year levels based on the Company's most recent forecast for the FPFTY; it is inclusive of any large transportation contract customer changes related to customers served under Rates LFD, XD, and IS. In particular, among other adjustments, this adjustment includes a net decrease of 3,815 Residential Heating customers (Rate R) from budgeted levels to anticipated end-of-test-year levels and a net decrease of 1,497 Commercial Heating customers (Rate N) from budgeted levels to anticipated end-of-FPFTY levels on September 30, 2026.

Q. How were these adjustments calculated?

A. UGI Gas Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments for the stated customer counts. In total, these adjustments decrease sales by 895 MMcf and decrease projected revenues by $10.563 million, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit SAE-4(b) can be found on

UGI Gas Exhibit SAE-4(b)(1), which provides a breakout of customer data for large transportation customer classes.

Q. Please explain the adjustment titled "Adjustment for Customer/Contract Changes – Large Transport and Interruptible Detail" as shown on UGI Gas Exhibit SAE-4(b)(1).

A. The adjustments for large transportation customers were developed by UGI Gas's marketing personnel following their review of individual large customer accounts and market segments. The adjustments reflect annualizing anticipated increases or reductions from original individual customer budgeted sales and revenues. There were no adjustments to the original budget for the Large Transport and Interruptible customers.

Q. Please explain your next adjustment, "Adjustment for Normalized & Annualized Use/Customer" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Normalized & Annualized Use/Customer" normalizes and annualizes usage per customer to projected end-of-test-year levels. Specifically, in developing usage per customer projections for the Company's core Residential Heating rate groups (Rates R and RT), the Company utilized an econometric regression model that incorporates four independent variables: (1) use per customer; (2) heating degree days; (3) lagged heating degree days; and (4) weighted time trend. While use per customer, heating degree days, and lagged heating degree days capture weather related usage factors, which can then be used to project normalized and annualized customer usage under normal weather conditions, the weighted time trend variable of this regression captures non-weather trends that underlie changes in usage per customer over time (*e.g.*, conservation). These trends can vary, but as a comprehensive variable, "trend" will capture the impacts of conservation, including but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying, and tracking all variables over time, a trend variable is used to provide a comprehensive indicator of usage trends, which can then be used to forecast for a future period. Additionally, the trend variable is weighted by heating degree days to reflect a "weighted trend," which more accurately reflects that the trends' impacts are directly related to usage during heating time periods.

For the Residential Heating groups of Rates R and RT, the multi-year period regression methodology is the same base method that the Company has utilized in prior rate cases, updated for the use of a common data set period of October 2003 through September 2024. October 2003 is the earliest common data set available for the entire service territory, given the timing and data availability of historic service and former rate district level details for UGI Gas and its former subsidiaries, UGI PNG and UGI CPG.

For the Company's core Commercial Heating rate groups (inclusive of Rates N, NT, and DS), the Company utilized the same regression method as presented in UGI Gas's 2019, 2020, and 2022 Gas Rate Cases. Specifically, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per customer; (2) heating degree days; and (3) lagged heating degree days. For the Commercial Heating group, the Company used the period of October 2012 through September 2024 for regression modeling, or the period during which common non-residential rate structures existed for UGI Gas and its former subsidiaries.

The forecasts for end-of-FPFTY use per customer are generated using the regression results along with a projection of regression variable inputs, including normal annual heating degree days and, where applicable, a weighted trend variable. The results are presented in summary on UGI Gas Exhibit SAE-4(a) and in detail on UGI Gas Exhibit SAE-4(c). In total, the result is a net sales increase, from the fiscal 2026 budget, of 1,165 MMcf, and a net revenue increase, from the fiscal 2026 budget, of $11.683 million, inclusive of PGC revenues.

Q. Why did UGI Gas utilize a multi-year regression period?

A. The Company decided to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends. Consequently, the multi-year regression period more accurately projects usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last eight base rate cases of UGI Gas and its predecessor entities.

Q. Has UGI Gas compared the results of the multi-year regression method to develop normalized usage for Residential Heating and Commercial Heating customer groups with any other normalization method?

A. Yes. Please see UGI Gas Exhibits SAE-3(a) and SAE-3(b), which contain use per customer graphs that illustrate the results of both the multi-year normalized regression method I have explained above ("Normalized Multi-year") and a short-term normalized

("Normalized 12 Months ended") value for the same groups of Residential Heating and Commercial Heating customers. The short-term normalized values are computed via a simple determination of temperature sensitive load each month during the 12 month period ending September 30, 2024. As can be seen from these graphs, short-term trend fluctuations of the "Normalized 12 months ended" line occur in certain periods, but consistently revert to the long-term "Normalized Multi-year" trend which has been used to forecast FPFTY use per customer values, thus capturing the ongoing base trend in declining use per customer.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit SAE-4(a) annualizes FPFTY PGC revenues using the PGC rate in effect as of December 1, 2024. UGI Gas Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment increases PGC revenues for the FPFTY by $11.515 million.

Q. Please explain the following three adjustments shown in summary on UGI Gas Exhibit SAE-4(a): "Adjustment for MFC," "Adjustment for USP," and "Adjustment for GPC."

A. The "Adjustment for MFC" annualizes the Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rates in effect as of December 1, 2024. The MFC Adjustment increases projected revenues by $0.201 million.

The "Adjustment for USP" annualizes the Company's Universal Service Program ("USP") surcharge revenues for the FPFTY based on the USP Rider rate in effect as of December 1, 2024. The Adjustment for USP also updates the sales volume for Customer

Assistance Program ("CAP") customers in the USP Revenue calculation with end of Fiscal Year 2024 data in comparison to the budgeted sales volume for CAP customers, which was calculated using end of Fiscal Year 2023 data. The USP adjustment increases revenues by $4.790 million.

The "Adjustment for GPC" annualizes the Gas Procurement Cost ("GPC") revenues to reflect the impact of all volume adjustments to the original Fiscal Year 2026 planned budget. The GPC adjustment decreases revenues by $0.040 million. Additional details for these three adjustments are provided in UGI Gas Exhibit SAE-4(e), UGI Gas Exhibit SAE-4(f), and UGI Gas Exhibit SAE-4(g), respectively.

Q. Please explain "Adjustment for Excess Take Revenues" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Excess Take" detailed in UGI Gas Exhibit SAE-4(h) reflects the assumption that large transportation customers will evaluate new service elections and will make the necessary adjustments to avoid Excess Take penalties in the FPFTY. The Excess Take adjustment reduces revenue by $1.7 million.

Q. Please explain "Adjustment for STAS" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for STAS" detailed in UGI Gas Exhibit SAE-4(i) annualizes the revenue for the State Tax Adjustment Surcharge ("STAS") for the FPFTY based on the STAS Rider rate in effect as of December 1, 2024. This adjustment increases revenues by $0.082 million.

Q. Please explain the "Adjustment for EEC Rider" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Rider" annualizes the revenue from the Energy Efficiency and Conservation ("EE&C") Rider ("EEC Rider") for the FPFTY based on the EEC Rider rate in effect as of December 1, 2024. This adjustment decreases revenues by $0.024 million and is shown on UGI Exhibit SAE-4(j).

Q. Please explain the "Adjustment for EEC Conservation Impact" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Conservation Impact" annualizes the impact to revenues from UGI Gas's ongoing EE&C programs and associated reduced energy consumption as a result of measures implemented as part of the EE&C programs. This adjustment decreases FPFTY sales by 240 MMcf and decreases revenues by $2.564 million and can be seen on UGI Gas Exhibit SAE-4(k).

Q. Please explain the "Adjustment for DSIC" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for DSIC" annualizes Distribution System Improvement Charge ("DSIC") revenue based on the application of the 5% DSIC charge cap to FPFTY revenues. The FPFTY budget utilized a rate of 4.46%. This adjustment applies a 5% DSIC rate in order to annualize the DSIC to end of FPFTY conditions. The 5% rate is currently projected to be effective at the end of the FTY, and that 5% capped rate will remain in place through the FPFTY period. This allows the Company to properly quantify DSIC revenues, which will be rolled into the new base rates established in this proceeding as a result of re-setting the DSIC rate to zero pursuant to 66 Pa. C.S. § 1358(b)(1). This adjustment increases revenues by $4.107 million and is shown on UGI Gas Exhibit SAE-4(l).

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and non-jurisdictional revenue?

A. Yes. Pursuant to the terms of the Revenue Sharing Incentive Mechanism in Section 11 of the UGI Gas tariff, these revenues are appropriately treated as below the line for ratemaking purposes and, thus, have been excluded.

III. DEVELOPMENT OF SALES AND REVENUE FOR THE FTY AND HTY

Q. How were normalized and annualized sales and revenue determined for the FTY?

A. Budgeted sales and revenues serve as the starting point for developing the normalized and annualized FTY sales and revenues, as shown in UGI Gas Exhibit SAE-5. All of the adjustments that were made in the development of the FPFTY sales and revenues were also made in the development of the FTY sales and revenues, with the exception of the adjustments for the EEC Conservation Impact that are contained in the FPFTY but not the FTY.

Q. How were normalized and annualized sales and revenue determined for the HTY?

A. Historic sales and revenues serve as the starting point for developing the normalized and annualized HTY sales and revenues shown in UGI Gas Exhibit SAE-6. All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, with the exception of the adjustments for the Weather Normalization Adjustment ("WNA"), EEC Conservation Impact, Gas Delivery

Enhancement ("GDE") Rider, and DSIC. The "Adjustment for WNA" in the HTY removes the revenues associated with the actual WNA revenue recorded in the HTY revenues and margins in order to not double count certain weather-related impacts, as the Adjustment for Normalized & Annualized Use/Customer fully incorporates weather related usage impacts. The EEC Conservation Impact is not required, as the actual HTY sales and revenue reflect such impacts. The "Adjustment for GDE" in the HTY annualizes GDE Rider revenue based on the current rate as of September 1, 2024.

Q. Is the Company proposing any change to the rate assessed under Rate NNS (No Notice Service)?

A. Yes. Rate NNS is a daily balancing service offered by the Company. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make an election under Rate NNS up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The Company is proposing to update the tariffed Rate NNS charge to reflect current cost elements, using the methodology agreed to in the Settlement from the Company's 2019 Gas Rate Case.

Q. How was the proposed Rate NNS charge developed?

A. The Rate NNS charge is a monthly charge established using the Company's cost of interstate storage that can be utilized for balancing excess or shortfall requirements on the Company system. UGI Gas Exhibit SAE-8 shows the calculation of the Rate NNS charge. This charge was developed based on the same methodology used in the Company's 2019

Gas Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate is $0.2040 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity. This compares to a current NNS rate of $0.2200 per Mcf/d of elected NNA, which was established in the Company's 2022 Gas Rate Case (see Paragraph 44 in the Recommended Decision issued on July 28, 2022 at Docket Nos. R-2021-3030218, *et al.*).

Q. Will the Company continue to credit the revenues received from Rate NNS to PGC Rates?

A. Yes, revenues from Rate NNS will continue to be credited to the PGC Rates as part of the Company's annual 1307(f) proceeding.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excess volumes, or receipt of shortfalls, in subsequent months.

Q. Has the Company proposed any changes to the Rate MBS rates?

A. Yes. UGI Gas Exhibit SAE-9 provides the basis for the MBS rate calculation. As a result of the settlement in the Company's 2019 Gas Rate Case, storage demand charges were included in the calculation of Rate MBS on a 100% load factor basis and the Company is continuing that inclusion in the proposed rates presented. The MBS rate is updated annually on December 1st each year, using 12 months of data ending in September, for the average monthly imbalance utilized in development of the rate. The MBS rates most recently updated for December 1, 2024, are: \$0.0115/Mcf for Rates DS and IS; \$0.0069/Mcf for Rate LFD; and \$0.0058/Mcf for Rate XD. As seen on UGI Gas Exhibit SAE-9, the proposed MBS rates will be: \$0.0128/Mcf for Rates DS and IS; \$0.0074/Mcf for Rate LFD; and \$0.0075/Mcf for Rate XD. These Rate MBS increases are principally driven by increases to the average capacity charge.

Q. Will the Company continue to credit the revenues received from Rate MBS to PGC Rates?

A. Yes, revenues from Rate MBS will continue to be credited to the PGC as part of the Company's annual 1307(f) proceeding.

Q. Please describe the GPC.

A. The GPC recovers costs associated with gas procurement that were unbundled from base rates.

Q. Is the Company proposing to update its GPC in this proceeding?

A. No. The Company proposes to continue the \$0.0660/Mcf blended rate that was approved in the Company's 2020 Gas Rate Case (see Joint Petition for Approval of Unopposed Settlement of All Issues, Appx. A, p. 12, filed on August 3, 2020, at Docket Nos. R-2019-3015162, *et al.*, which was approved by the Commission's Opinion and Order entered on October 8, 2020, in that proceeding).

Q. Please describe the MFC.

A. The MFC is equal to the fixed percentage of purchased gas costs that are expected to be uncollectible.

Q. Is the Company proposing to update its MFC in this proceeding?

A. Yes. The Company is updating the percentages for the MFC rates to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will be 2.56%, and the MFC for the commercial class will be 0.56%. Please see UGI Gas Exhibit SAE-10 for additional details.

Q. Please describe the USP Rider.

A. The USP Rider recovers those costs associated with the provision of universal service offerings approved by the Commission in the Company's Universal Service and Energy Conservation Plan.

Q. Is the Company proposing any changes to the USP Rider?

A. Yes. The Company is proposing changes to the annual reconciliation provisions of Rider F – Universal Service Program "USP" to update the threshold number of customers enrolled in CAP that is used in the calculation of the offset applied to recoverable CAP costs. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would arguably have occurred if not for CAP. The Company proposes to set the CAP enrollee threshold equal to the number of CAP participants as of September 30, 2025, to provide an enrollee figure that reflects the actual ongoing impacts on CAP enrollment. This proposal is consistent with the establishment of the CAP enrollee figure in the UGI Gas 2020 Rate Case at Docket No. R-2019-3015162.

IV. TARIFF CHANGES

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement number, Notice language, Issue and Effective dates, and page numbers as necessary per this case. Apart from the proposed rate schedule changes, a complete list of tariff modifications can be found in the List of Changes Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 55 to UGI Gas Tariff No. 7 and Proposed Supplement No. 55 to UGI Gas Tariff No. 7S. As discussed in the direct testimony of John D. Taylor, UGI Gas Statement No. 10, the Company is proposing to complete the unification of Rate DS for the former North and South/Central Rate Districts, which is the only distribution rate remaining to be unified since the Commission-approved merger of UGI Central Penn Gas, Inc. and UGI Penn Natural Gas, Inc. into UGI Utilities, Inc.[1] Relatedly, UGI Gas is proposing to fully consolidate the listings of counties served in the Description of Territories Served, which are currently apportioned by the three former Rate Districts. More significant proposed changes to the tariffs include:

- The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset to 0.00%.
- Rider D – MFC has been set to 2.56% for PGC Residential Customers and 0.56% for Non-Residential PGC Customers, as described above.

[1] See Joint Application of UGI Utilities, Inc., UGI PNG and UGI CPG for Certificate of Public Convenience for Merger, Docket Nos. A-2018-30000381, A-2018-30000382 and A-2018-2018-30000383 (Opinion and Order entered Sept. 20, 2018).

- Section 15. Price to Compare ("PTC") has been updated to reflect changes to the MFC.
- Rider F – Universal Service Program has been revised so that the CAP credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2025, in place of the existing September 30, 2022 date.
- Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b)(1).
- Definitions – Added definitions for daily and monthly price publications and replaced references to Gas Daily and Inside FERC. Clarified that the closest applicable alternative price location may be used if reference price locations are unavailable to the Company. This change is intended to address possible changes in index publications whereby the Company will be able to update pricing, if needed, without interruption in tariff application.
- Rule 22 – Replaced references to index with Reference Prices to comport with the added definitions of daily and monthly price publications.
- Unauthorized Overruns – Aligned minimum charge across all rate classes, increasing the charge for Rate LFD and Rate XD customers to $50 from $27.50. Clarified that the Maximum Daily Excess Balancing Charge in Section 22.4 may also be used in the calculation of Unauthorized Overrun pricing.
- Updated residential and commercial purchase of receivables rates due to the change in the MFC.
- Aggregation Agreement Definitions – Clarified the nomination procedure's location on the Energy Management Website and added definitions for Choice Aggregator, Choice Broker, and Choice Natural Gas Supplier.

Q. Is the Company proposing any additional tariff changes?

A. Yes. The Company is proposing two updates to Rate IS. The first revision adds clarifying language which requires manual interruptible ("MI") customers to maintain the ability to transfer the fuel source of its interruptible equipment from natural gas to an alternate fuel manually. Additionally, the second revision is the elimination of tariff-defined take-or-pay minimum annual bill volumes for Rate IS (Automatic Temperature Controlled ("ATC) or MI) customers.

Q. Please describe the revision for the MI customers.

A. In lieu of the existing Off-Peak Period usage requirement of 5,000 MCF for the April through October seasonal period, the Company is proposing an annualized minimum usage requirement to qualify as an MI Rate IS customer. This revision better aligns customer obligations with the Company's application of its right to interrupt non-firm gas service for Rate IS at all times and aligns with the Company's peak day analysis, which assumes MI customers are off the system.

Q. Please describe the revision for the ATC customers.

A. In lieu of the existing annual usage requirement of 500 MCF for ATC customers, minimums will be incorporated in Rate IS service contracts. This revision better aligns customer obligations with the Company's application of its right to interrupt non-firm gas service for Rate IS at all times and aligns with the Company's peak day analysis, which assumes ATC customers are off the system.

Q. Will this update materially impact the MI customers?

A. No, the Company anticipates this will have a negligible impact on its customer base because MI customers are familiar with the nature of their service from the Company, as outlined in the tariff and their interruptible service agreements. Associated per customer minimums will be established and maintained on a per customers basis going forward.

Q. Please explain the elimination of tariff-defined annual minimum bill volumes for Rate IS customers.

A. The Company has determined that it would be simpler and more efficient to rely on the interruptible service agreements to define any minimal annual bill volumes, which can vary materially in accordance with customer equipment configurations and sizing. Today, the majority of Rate IS customers have a predetermined negotiated minimum annual bill volume in their interruptible service agreements. By removing the annual minimum bill volume from the tariff, UGI Gas will clarify that such minimum annual bill volumes may be subject to negotiation and may vary by customer.

Q. How many Rate IS customers have annual minimum bill values specified in their interruptible service agreements?

A. As of September 2024, the Company had 258 Rate IS customers in Pennsylvania. A majority of this population has a minimum annual bill volume specified in their interruptible service agreements with the Company. Upon contract renewals, related minimum bill amounts will be incorporated into contracts for those not already in place.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

<u>Work Experience</u>

<u>UGI Utilities, Inc., Denver, PA</u>

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

<u>UGI Utilities, Inc., Reading, PA</u>

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

<u>Education</u>

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

<u>Previous testimony provided before the Pennsylvania Public Utility Commission</u>:

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

UGI GAS

EXHIBIT SAE-2

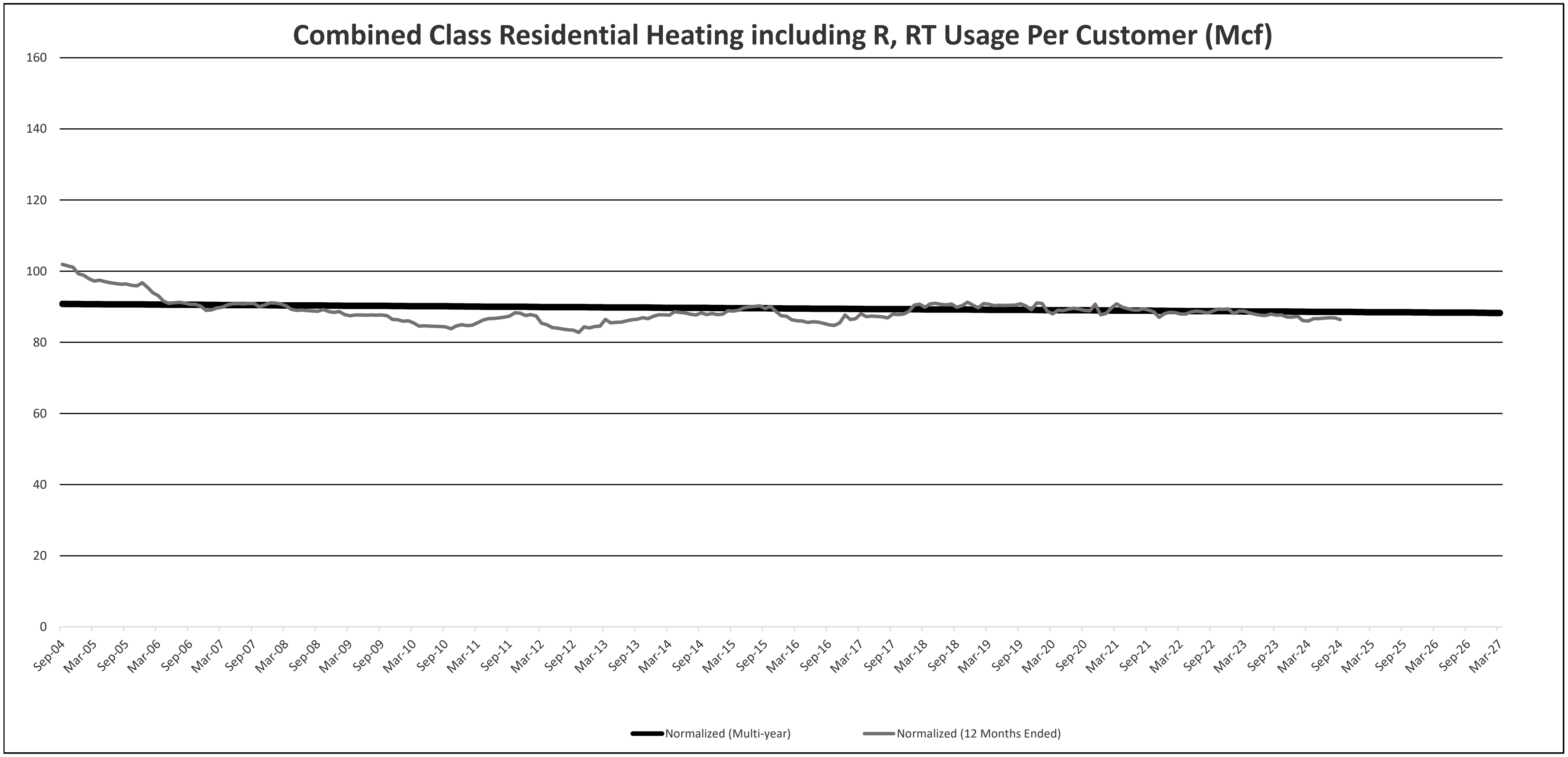
UGI Utilities, Inc. - Gas Divison
15 Year Normal Heating Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average *
Jan	1,195	891	996	1,053	1,292	1,154	1,251	999	1,042	1,313	1,236	1,132	956	1,150	1,140	1,120
Feb	943	953	1,178	977	931	1,018	947	813	975	1,114	1,282	915	714	769	900	962
Mar	950	774	816	823	777	627	834	484	882	974	961	578	865	904	826	805
Apr	391	391	550	373	425	327	414	431	424	464	409	464	261	567	318	414
May	282	198	144	279	180	154	126	70	175	153	88	221	206	62	119	164
Jun	21	46	27	26	43	25	20	37	21	15	36	24	32	30	27	30
Jul	4	4	20	7	20	5	1	1	5	14	6	3	3	3	1	0
Aug	5	11	24	23	19	9	11	8	15	16	11	2	20	2	7	16
Sep	47	129	79	85	116	68	75	110	140	100	47	53	90	58	34	83
Oct	357	431	227	467	436	383	399	336	330	305	385	319	230	365	272	350
Nov	613	555	741	724	569	670	559	782	774	764	516	586	687	771	769	672
Dec	1,121	814	1,008	1,016	1,052	1,162	841	844	1,009	916	631	974	1,086	883	926	952
Totals	5,929	5,197	5,810	5,853	5,860	5,602	5,478	4,915	5,792	6,148	5,608	5,271	5,150	5,564	5,339	5,568

*Average adjusted for rounding of 15 year calculation and normal representation of Heating Degree Days falling consecutively through normal year.

UGI GAS

EXHIBIT SAE-3(a) – (b)



Combined Class Residential Heating including R, RT Usage Per Customer (Mcf)
160
140
120
100
80
60
40
20
0
Sep-04
Mar-05
Sep-05
Mar-06
Sep-06
Mar-07
Sep-07
Mar-08
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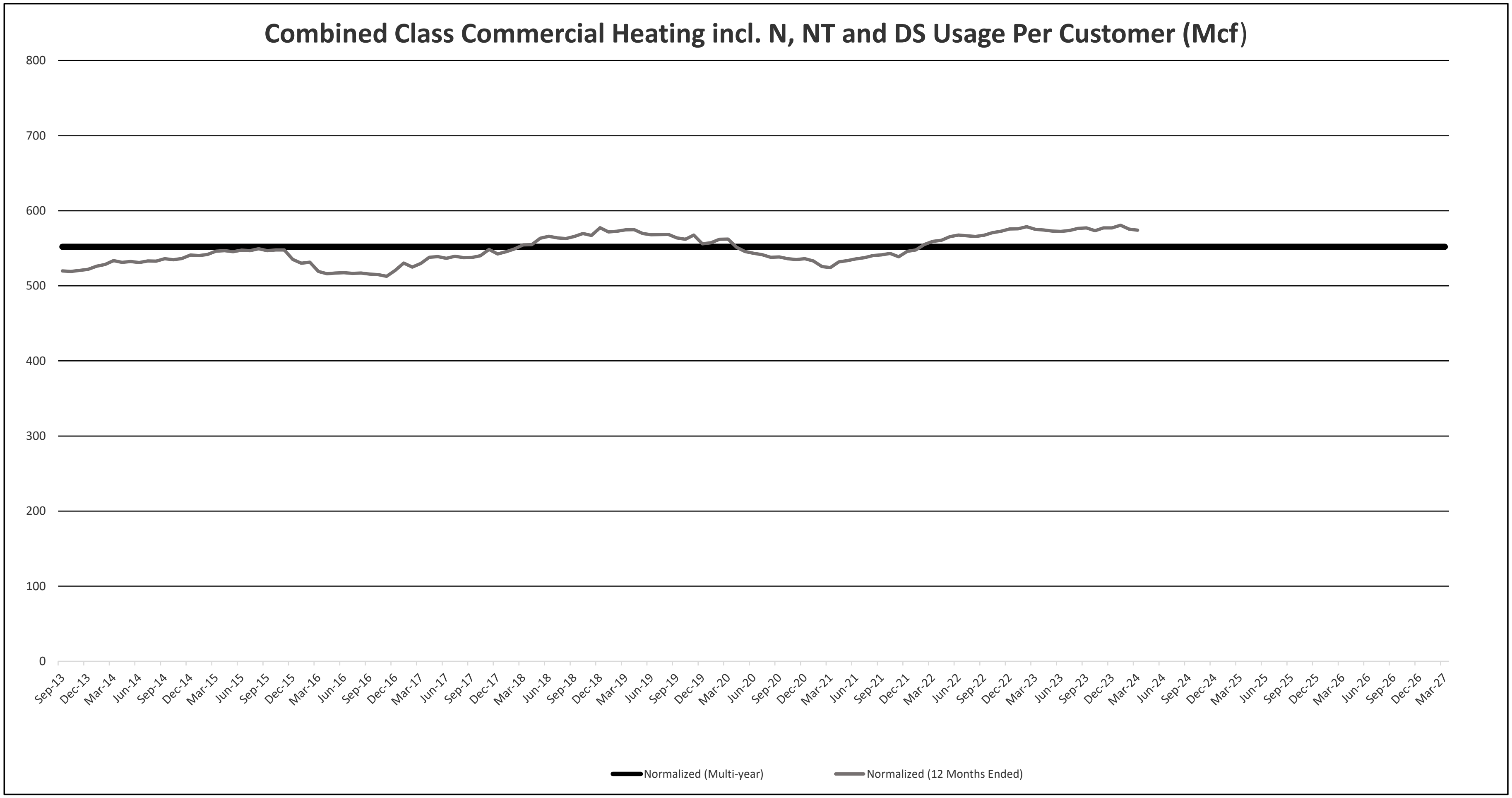
Mar-26
Sep-26
Mar-27
Normalized (Multi-year)
Normalized (12 Months Ended)


Combined Class Commercial Heating incl. N, NT and DS Usage Per Customer (Mcf)
800
700
600
500
400
300
200
100
0
Sep-13 Dec-13 Mar-14 Jun-14 Sep-14 Dec-14 Mar-15 Jun-15 Sep-15 Dec-15 Mar-16 Jun-16 Sep-16 Dec-16 Mar-17 Jun-17 Sep-17 Dec-17 Mar-18 Jun-18 Sep-18 Dec-18 Mar-19 Jun-19 Sep-19 Dec-19 Mar-20 Jun-20 Sep-20 Dec-20 Mar-21 Jun-21 Sep-21 Dec-21 Mar-22 Jun-22 Sep-22 Dec-22 Mar-23 Jun-23 Sep-23 Dec-23 Mar-24 Jun-24 Sep-24 Dec-24 Mar-25 Jun-25 Sep-25 Dec-25 Mar-26 Jun-26 Sep-26 Dec-26 Mar-27
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-4(a) – (l)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2026 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2026	344,714	1,108,563	723,506	
Adjustment for Customer/Contract Changes	(895)	(10,563)	(5,447)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	1,165	11,683	7,713	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		11,515	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		201	201	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		4,790	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(40)	(40)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(h)
Adjustment for STAS		82	82	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Rider		(24)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for EEC Conservation Impact	(240)	(2,564)	(1,277)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for DSIC		4,107	4,107	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Fully Projected Future Test Year 2026	344,744	1,126,050	727,146	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FPFTY Revenues (Unadjusted)	$ 7,433	$ 632,170	$ 55,406	$ 8,246	$ 175,058	$ 8,140	$ 67,290	$ 35,092	$ 119,727	$ 1,108,563
2	FPFTY PGC Revenues	$ (1,911)	$ (277,218)	$ (4,404)	$ (4,143)	$ (91,223)	$ (4,541)	$ (412)	(929)	(277)	(385,057)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 5,522	$ 354,952	$ 51,002	$ 4,103	$ 83,835	$ 3,599	$ 66,878	$ 34,163	$ 119,450	$ 723,506
4	FPFTY Average Effective Customers (Unadjusted)	20,046	530,780	81,425	2,945	46,215	609	21,251	1,330	1,002	705,603
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 0.275	$ 0.669	$ 0.626	$ 1.393	$ 1.814	$ 5.910	$ 3.147	$ 25.686	$ 119.212	$ 1.025
6	FPFTY Customers (Fully Adjusted)	19,875	526,965	81,425	2,905	44,718	596	21,251	1,330	1,002	700,067
7	Change in Customers during FPFTY (L6 - L4)	(171)	(3,815)	-	(40)	(1,497)	(13)	-	-	-	(5,536)
8	Annualization of Margin (L5 * L7)	$ (47)	$ (2,551)	$ -	$ (56)	$ (2,716)	$ (77)	$ -	$ -	$ -	$ (5,447)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.371	$ 1.191	$ 0.680	$ 2.800	$ 3.788	$ 13.366	$ 3.166	$ 26.385	$ 119.488	$ 1.571
10	Annualization of Total FPFTY Revenue (L7 * L9)	$ (63)	$ (4,544)	$ -	$ (112)	$ (5,671)	$ (174)	$ -	$ -	$ -	$ (10,563)
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	$ (16)	$ (1,993)	$ -	$ (56)	$ (2,955)	$ (97)	$ -	$ -	$ -	$ (5,117)
12	Total FPFTY UPC (Unadjusted) - MCF	15.60	85.60	80.80	256.80	359.50	1,360.20	700.30	6,763.20		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(3)	(327)	-	(10)	(538)	(18)	-	-	-	(895)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-4(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FPFTY Revenues (Unadjusted)	$ 56,288	$ 39,074	$ 2,395	$ 21,970	$ 119,727
2	FPFTY PGC Revenues	(277)	-	-	-	(277)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 56,012	$ 39,074	$ 2,395	$ 21,970	$ 119,450
4	FPFTY Average Effective Customers (Unadjusted)	631	55	58	258	1,002
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 88.767	$ 710.438	$ 41.286	$ 85.154	$ 119.212
6	FPFTY Customers (Fully Adjusted)	631	55	58	258	1,002
7	Change in Customers during FPFTY (L6 - L4)	-	-	-	-	-
8	Annualization of Margin	$ -	$ -	$ -	$ -	$ -
9	Average Annual Revenue Per Customer (L1 / L4)	$ 89.205	$ 710.438	$ 41.286	$ 85.154	$ 119.488
10	Annualization of Total FPFTY Revenue	$ -	$ -	$ -	$ -	$ -
11	Annualization of FPFTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FPFTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FPFTY Sales - MMCF	-	-	-	-	-

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Reconciliation Adj. *	[11] Total
1	FPFTY (Unadjusted) Use/Customer ("UPC") - MCF	15.60	85.60	80.80	256.80	359.50	1,360.20	700.30	6,763.20			
2	FPFTY UPC (Fully Adjusted) - MCF	16.30	88.70	81.90	249.70	340.20	905.40	727.70	6,763.20			
3	Change in UPC - MCF (L2 - L1)	0.70	3.10	1.10	(7.10)	(19.30)	(454.80)	27.40	0.00			
4	FPFTY Customers (Fully Adjusted)	19,875	526,965	81,425	2,905	44,718	596	21,251	1,330	1,002	-	700,067
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	14	1,634	90	(21)	(863)	(271)	582	-	-	-	1,165
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 167	$ 19,592	$ 558	$ (201)	$ (8,390)	$ (2,635)	$ 2,368	$ -		$ 224	$ 11,683
7	Total Unit Revenue Adjustment (L6 / L5)	$ 11.9932	$ 11.9932	$ 6.2309	$ 9.7217	$ 9.7217	$ 9.7217	$ 4.0676	$ -	$ -		
8	Distribution Margin Adjustment (L5 * L9)	$ 72	$ 8,456	$ 464	$ (79)	$ (3,312)	$ (1,040)	$ 2,235	$ -			$ 6,795
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.1755	$ -		
10	PGC Revenue (L5 * L11)	$ 78	$ 9,194	$ -	$ (116)	$ (4,857)	$ (1,526)	$ -	$ -		$ (99)	$ 2,675
11	PGC Unit Rate	$ 5.6281	$ 5.6281		$ 5.6281	$ 5.6281	$ 5.6281					
12	EE&C Revenue Adjustment (L5 * L13)	$ 3	$ 295	$ 16	$ (1)	$ (31)	$ (10)	$ 21	$ -			$ 293
13	EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0888	$ -		
14	USP Revenue Adjustment (L5 * L15)	$ 8	$ 943	$ 52	$ -	$ -	$ -	$ -	$ -	$ -		$ 1,002
15	USP Unit Rate	$ 0.5770	$ 0.5770	$ 0.5770	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 2	$ 209		$ (1)	$ (21)	$ (7)					$ 182
17	MFC Unit Rate	$ 0.1278	$ 0.1278		$ 0.0248	$ 0.0248	$ 0.0248					
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 4	$ 495	$ 27	$ (4)	$ (168)	$ (53)	$ 113	$ -			$ 414
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500			
20	Total Margin Adjustment (L8 + L16 + L18)	$ 78	$ 9,160	$ 490	$ (84)	$ (3,502)	$ (1,100)	$ 2,347	$ -		$ 322	$ 7,713
21	Total Unit Margin Adjustment (L20 / L5)	$ 5.6073	$ 5.6073	$ 5.4731	$ 4.0575	$ 4.0575	$ 4.0575	$ 4.0315	$ -	$ -		

Notes:

* Column (10) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for PGC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FPFTY	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FPFTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes	3,322	7,176	10,059	13,158	10,510	8,674	4,429	2,129	1,143	984	1,015	1,446	64,044
PGC Revenue Adjustment	$597	$1,290	$1,809	$2,366	$1,890	$1,560	$796	$383	$206	$177	$182	$260	$11,515

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for MFC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget PGC Rate FPFTY	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FPFTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes-Rate R	2,390	5,164	7,207	9,399	7,525	6,230	3,186	1,517	791	673	697	1,019	
Total PGC Volumes-Rate N	933	2,011	2,851	3,759	2,984	2,443	1,243	611	352	310	318	428	
Total PGC Volumes	3,322	7,176	10,059	13,158	10,510	8,674	4,429	2,129	1,143	984	1,015	1,446	64,044
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	
MFC Rate N Adj Rate	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
Rate R Revenue Variance	$10	$21	$29	$38	$31	$25	$13	$6	$3	$3	$3	$4	
Rate N Revenue Variance	$1	$2	$2	$3	$2	$2	$1	$0	$0	$0	$0	$0	
Total Revenue Variance	$10	$23	$32	$41	$33	$27	$14	$7	$4	$3	$3	$4	$201

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for USP

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original FPFTY Budget USP Calculation	$1,226	$2,651	$3,702	$4,831	$3,864	$3,196	$1,632	$778	$408	$349	$361	$524	$23,521
Corrected FPFTY Budget USP Calculation	$1,200	$2,595	$3,624	$4,730	$3,782	$3,128	$1,598	$762	$400	$341	$353	$513	$23,027
Variance to Original FPFTY Budget Calculation	($26)	($56)	($78)	($101)	($81)	($67)	($34)	($16)	($9)	($7)	($8)	($11)	($494)
Original FPFTY Budget USP Rate	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	
FPFTY USP Rate	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	
USP Rate Variance	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	
Total Rate R Volumes	2,730	5,903	8,243	10,758	8,604	7,117	3,635	1,734	909	776	803	1,168	52,378
Total Rate R excl CAP Volumes	2,557	5,530	7,722	10,079	8,060	6,666	3,405	1,624	852	727	752	1,094	49,067
USP Rate Revenue Variance	$275	$596	$832	$1,085	$868	$718	$367	$175	$92	$78	$81	$118	$5,285
Total Revenue Variance	$250	$540	$754	$984	$787	$651	$332	$159	$83	$71	$73	$107	$4,790

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for GPC

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
GPC Rate FPFTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FPFTY Budget	(31)	(65)	(94)	(123)	(98)	(80)	(41)	(21)	(13)	(11)	(12)	(15)	(604)
Revenue Variance	($2)	($4)	($6)	($8)	($6)	($5)	($3)	($1)	($1)	($1)	($1)	($1)	($40)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for STAS

	@ -0.14% Unadjusted 2026 TOTAL	@ -0.13% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (10)	$ (10)	$ 0
Residential-Heating	$ (886)	$ (858)	$ 28
Residential-RT	$ (78)	$ (74)	$ 4
Total R/RT	$ (974)	$ (942)	$ 33
Commercial-Non Htg	$ (12)	$ (11)	$ 1
Commercial- Htg	$ (245)	$ (214)	$ 32
Commercial-NT	$ (89)	$ (86)	$ 3
Industrial	$ (11)	$ (7)	$ 4
Industrial-NT	$ (6)	$ (5)	$ 0
Total N/NT	$ (363)	$ (323)	$ 40
Total DS	$ (49)	$ (46)	$ 3
Total LFD	$ (79)	$ (72)	$ 7
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (1,465)	$ (1,383)	$ 82

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for EEC Rider

	OCT 2025	NOV 2025	DEC 2025	JAN 2026	FEB 2026	MAR 2026	APR 2026	MAY 2026	JUN 2026	JUL 2026	AUG 2026	SEP 2026	TOTAL
Original Budget FPFTY R/RT Rate	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
FPFTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
R/RT Rate Variance	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	
R/RT Rate Volumes	2,730	5,903	8,243	10,758	8,604	7,117	3,635	1,734	909	776	803	1,168	52,378
R/RT Revenue Adjustment	($53)	($114)	($159)	($208)	($166)	($137)	($70)	($33)	($18)	($15)	($15)	($23)	($1,011)
Original Budget FPFTY N/NT Rate	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
FPFTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
N/NT Rate Variance	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	
N/NT Rate Volumes	1,790	3,611	5,001	6,505	5,213	4,318	2,304	1,233	787	715	729	921	33,126
N/NT Revenue Adjustment	$15	$30	$42	$55	$44	$36	$19	$10	$7	$6	$6	$8	$278
Original Budget FPFTY DS Rate	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
FPFTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
DS Rate Variance	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	
DS Rate Volumes	476	798	1,241	1,601	1,438	1,197	695	421	298	258	263	311	8,995
DS Revenue Adjustment	($4)	($7)	($11)	($14)	($13)	($11)	($6)	($4)	($3)	($2)	($2)	($3)	($81)
Original Budget FPFTY LFD Rate	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
FPFTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
LFD Rate Variance	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	
LFD Rate Volumes	2,101	2,372	2,662	2,894	2,593	2,490	2,153	1,981	1,831	1,804	1,834	1,875	26,589
LFD Revenue Adjustment	$62	$70	$79	$86	$77	$74	$64	$59	$54	$54	$54	$56	$790
Total Revenue Adjustment	$20	($20)	($49)	($81)	($58)	($38)	$7	$32	$41	$42	$43	$38	($24)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 10/01/2025)

Yearly Gas Savings by Rate Class 2026 - 2041 (Cumulative MMBtus)

Rate Class Description	*Fiscal Year* 2026	2027	2028	2029	2030	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY26 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	187,035	198,006	206,266	214,128	223,043	205,696	1.034	198,932	604,631	**(0.3)**
Nonresidential (N/NT)	35,354	38,780	41,988	46,016	48,158	42,059	1.034	40,676	65,020	**(0.6)**
Total	**222,389**	**236,786**	**248,254**	**260,144**	**271,201**	**247,755**		**239,608**	**669,651**	

Description	[1] Rate R Residential-Htg	[2] Rate RT Residential Htg-RT	[3] Rate N Commercial-Htg	[4] Rate NT Commercial Htg-NT	[5] Rate N Industrial	[6] Rate NT Industrial -NT	[7] Total
FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	88.7	85.0	340.2	703.3	905.4	2,085.5	
FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	88.4	84.7	339.6	702.7	904.8	2,084.9	
Change in UPC -MCF	(0.3)	(0.3)	(0.6)	(0.6)	(0.6)	(0.6)	
End of Year FPFTY Customers	526,965	77,666	44,718	19,240	596	466	669,651
Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(173)	(26)	(28)	(12)	(0)	(0)	(240)
Total Revenue Adjustment (L10 + L12 + L14 + L22)	$ (2,079)	$ (159)	$ (272)	$ (49)	$ (4)	$ (1)	$ (2,564)
Total Unit Revenue Adjustment (L6 / L5)	11.9932	6.2309	9.7217	4.0676	9.7217	4.0676	10.7021
Distribution Margin Adjustment (L5 * L9)	$ (897)	$ (132)	$ (107)	$ (46)	$ (1)	$ (1)	$ (1,186)
Distribution Unit Rate (Rates N, DS Weighted Value by District)	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	
PGC Revenue (L5 * L11)	$ (976)	$ -	$ (157)	$ -	$ (2)	$ -	$ (1,135)
PGC Unit Rate	$ 5.6281		$ 5.6281		$ 5.6281		
EE&C Revenue Adjustment (L5 * L13)	$ (31)	$ (5)	$ (1)	$ (0)	$ (0)	$ (0)	$ (37)
EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	
USP Revenue Adjustment (L5 * L15)	$ (100)	$ (15)					$ (115)
USP Unit Rate	$ 0.5770	$ 0.5770					
MFC Revenue/Margin Adjustment (L5 * L17)	$ (22)		$ (1)		$ (0)		$ (23)
MFC Unit Rate	$ 0.1278		$ 0.0248		$ 0.0248		
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ (53)	$ (8)	$ (5)	$ (2)	$ (0)	$ (0)	$ (68)
DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	
Total Margin Adjustment (L8 + L16 + L18)	$ (972)	$ (140)	$ (114)	$ (49)	$ (2)	$ (1)	$ (1,277)
Total Unit Margin Adjustment (L20 / L5)	$ 5.6073	$ 5.4731	$ 4.0575	$ 4.0315	$ 4.0575	$ 4.0315	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year - 12 Months Ended September 30, 2026
($ in Thousands)

Adjustment for DSIC

	@ 4.46% Unadjusted 2026 TOTAL	@ 5% Adjusted 2026 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ 245	$ 278	$ 33
Residential-Heating	$ 16,448	$ 18,937	$ 2,489
Subtotal Residential-Rate R	$ 16,693	$ 19,214	$ 2,522
Residential-RT	$ 2,369	$ 2,704	$ 335
Total Residential	$ 19,062	$ 21,918	$ 2,857
Commercial-Non Htg	$ 177	$ 192	$ 15
Commercial- Htg	$ 3,610	$ 3,754	$ 144
Subtotal Commercial- Rate N	$ 3,786	$ 3,945	$ 159
Commercial-NT	$ 2,700	$ 3,143	$ 443
Commercial-DS	$ 1,219	$ 1,363	$ 144
Commercial-IS	$ 409	$ 459	$ 50
Commericial-XD-F	$ 293	$ 328	$ 35
Commercial-XD-I	$ 30	$ 34	$ 4
Commercial-LFD	$ 925	$ 1,020	$ 94
Total Commercial	$ 9,362	$ 10,292	$ 930
Industrial	$ 155	$ 117	$ (38)
Subtotal Industrial- Rate N	$ 155	$ 117	$ (38)
Industrial-NT	$ 177	$ 199	$ 22
Industrial-DS	$ 279	$ 312	$ 33
Industrial-IS	$ 511	$ 573	$ 62
Industrial-XD-F	$ 698	$ 782	$ 84
Industrial-XD-I	$ 60	$ 68	$ 7
Industrial-LFD	$ 1,475	$ 1,626	$ 151
Total Industrial	$ 3,356	$ 3,677	$ 321
Grand Total	$ 31,779	$ 35,886	$ 4,107

UGI GAS

EXHIBIT SAE-5(a) – (k)

UGI Utilities Inc.- Gas Division
Future Test Year 2025 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2025	344,089	1,094,422	720,427	
Adjustment for Customer/Contract Changes	(685)	(10,355)	(5,232)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	839	8,727	5,840	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		21,079	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		368	368	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		4,787	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(41)	(41)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(h)
Adjustment for STAS		107	107	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for EEC Rider		(28)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for DISC		3,831	3,831	UGI Utilites, Inc.- Gas Division-Exhibit SAE-5(k)
Future Test Year 2025	344,243	1,121,199	723,601	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FTY Revenues (Unadjusted)	$ 7,645	$ 620,137	$ 55,581	$ 8,432	$ 172,714	$ 8,401	$ 67,743	$ 35,089	$ 118,679	$ 1,094,422
2	FTY PGC Revenues	$ (1,939)	$ (268,341)	$ (4,423)	$ (4,182)	$ (88,870)	$ (4,624)	$ (415)	(928)	(272)	(373,996)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 5,706	$ 351,796	$ 51,158	$ 4,250	$ 83,845	$ 3,777	$ 67,328	$ 34,161	$ 118,407	$ 720,427
4	FTY Average Effective Customers (Unadjusted)	20,634	524,742	81,425	3,017	46,058	637	21,251	1,329	998	700,091
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 0.277	$ 0.670	$ 0.628	$ 1.409	$ 1.820	$ 5.929	$ 3.168	$ 25.704	$ 118.644	$ 1.029
6	FTY Customers (Fully Adjusted)	20,422	520,755	81,425	2,978	44,547	624	21,251	1,329	1,003	694,334
7	Change in Customers during FTY (L6 - L4)	(212)	(3,987)	-	(39)	(1,511)	(13)	-	-	5	(5,757)
8	Annualization of Margin (L5 * L7)	$ (59)	$ (2,673)	$ -	$ (55)	$ (2,751)	$ (77)	$ -	$ -	$ 382	$ (5,232)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.371	$ 1.182	$ 0.683	$ 2.795	$ 3.750	$ 13.189	$ 3.188	$ 26.403	$ 118.917	$ 1.563
10	Annualization of Total FTY Revenue (L7 * L9)	$ (79)	$ (4,712)	$ -	$ (109)	$ (5,666)	$ (171)	$ -	$ -	$ 382	$ (10,355)
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	$ (20)	$ (2,039)	$ -	$ (54)	$ (2,916)	$ (94)	$ -	$ -	$ -	$ (5,123)
12	Total FTY UPC (Unadjusted) - MCF	15.80	86.00	81.10	260.60	361.10	1,366.30	705.60	6,759.40		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(3)	(343)	-	(10)	(546)	(18)	-	-	235	(685)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-5(b)(1)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FTY Revenues (Unadjusted)	$ 55,640	$ 38,785	$ 2,365	$ 21,889	$ 118,679
2	FTY PGC Revenues	(272)	-	-	-	(272)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 55,367	$ 38,785	$ 2,365	$ 21,889	$ 118,407
4	FTY Average Effective Customers (Unadjusted)	627	55	58	258	998
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 88.305	$ 705.182	$ 40.779	$ 84.842	$ 118.644
6	FTY Customers (Fully Adjusted)	632	55	58	258	1,003
7	Change in Customers during FTY (L6 - L4)	5	-	-	-	5
8	Annualization of Margin	$ 654	$ (175)	$ -	$ (97)	$ 382
9	Average Annual Revenue Per Customer (L1 / L4)	$ 88.739	$ 705.182	$ 40.779	$ 84.842	$ 118.917
10	Annualization of Total FTY Revenue	$ 654	$ (175)	$ -	$ (97)	$ 382
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	380	(113)	-	(32)	235

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	FTY (Unadjusted) Use/Customer ("UPC") - MCF	15.80	86.00	81.10	260.60	361.10	1,366.30	705.60	6,759.40		
2	FTY UPC (Fully Adjusted) - MCF	16.30	88.90	81.90	253.60	339.70	978.40	727.70	6,759.40		
3	Change in UPC - MCF (L2 - L1)	0.50	2.90	0.80	(7.00)	(21.40)	(387.90)	22.10	0.00		
4	FTY Customers (Fully Adjusted)	20,422	520,755	81,425	2,978	44,547	624	21,251	1,329	1,003	694,334
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	10	1,510	65	(21)	(953)	(242)	470	-	-	839
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 122	$ 18,112	$ 406	$ (203)	$ (9,268)	$ (2,353)	$ 1,910	$ -	$ -	$ 8,727
7	Total Unit Revenue Adjustment (L6 / L5)	$ 11.9932	$ 11.9932	$ 6.2309	$ 9.7217	$ 9.7217	$ 9.7217	$ 4.0676	$ -	$ -	
8	Distribution Margin Adjustment (L5 * L9)	$ 53	$ 7,817	$ 337	$ (80)	$ (3,659)	$ (929)	$ 1,802	$ -	$ -	$ 5,342
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.1795	$ -	
10	PGC Revenue (L5 * L11)	$ 57	$ 8,499	$ -	$ (117)	$ (5,365)	$ (1,362)	$ -	$ -	$ -	$ 1,712
11	PGC Unit Rate	$ 5.6281	$ 5.6281		$ 5.6281	$ 5.6281	$ 5.6281				
12	EE&C Revenue Adjustment (L5 * L13)	$ 2	$ 273	$ 12	$ (1)	$ (34)	$ (9)	$ 17	$ -	$ -	$ 260
13	EE&C Unit Rate	$ 0.1808	$ 0.1808	$ 0.1808	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0361	$ 0.0888	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ 6	$ 871	$ 38	$ -	$ -	$ -	$ -	$ -	$ -	$ 915
15	USP Unit Rate	$ 0.5770	$ 0.5770	$ 0.5770	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 1	$ 193		$ (1)	$ (24)	$ (6)				$ 164
17	MFC Unit Rate	$ 0.1278	$ 0.1278		$ 0.0248	$ 0.0248	$ 0.0248				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 3	$ 458	$ 19	$ (4)	$ (186)	$ (47)	$ 91	$ -	$ -	$ 334
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500		
20	Total Margin Adjustment (L8 + L16 + L18)	$ 57	$ 8,468	$ 357	$ (85)	$ (3,868)	$ (982)	$ 1,893	$ -	$ -	$ 5,840
21	Total Unit Margin Adjustment (L20 / L5)	$ 5.6073	$ 5.6073	$ 5.4731	$ 4.0575	$ 4.0575	$ 4.0575	$ 4.0315	$ -	$ -	

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for PGC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget PGC Rate FTY	$4.5259	$4.5259	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$1.1022	$1.1022	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes	3,296	7,117	9,978	13,072	10,446	8,626	4,415	2,162	1,185	1,026	1,057	1,436	63,815
PGC Revenue Adjustment	$3,632	$7,845	$1,794	$2,350	$1,878	$1,551	$794	$389	$213	$184	$190	$258	$21,079

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for MFC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget PGC Rate FTY	$4.5259	$4.5259	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	$5.4483	
FTY PGC Rate	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	$5.6281	
PGC Rate Variance	$1.1022	$1.1022	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	$0.1798	
Total PGC Volumes-Rate R	2,362	5,106	7,128	9,309	7,457	6,176	3,164	1,534	816	699	722	1,007	
Total PGC Volumes-Rate N	933	2,011	2,850	3,763	2,990	2,450	1,250	628	369	327	334	429	
Total PGC Volumes	3,296	7,117	9,978	13,072	10,446	8,626	4,415	2,162	1,185	1,026	1,057	1,436	63,815
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	$0.0250	$0.0250	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	$0.0041	
MFC Rate N Adj Rate	$0.0048	$0.0048	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	$0.0008	
Rate R Revenue Variance	$59	$128	$29	$38	$30	$25	$13	$6	$3	$3	$3	$4	
Rate N Revenue Variance	$5	$10	$2	$3	$2	$2	$1	$0	$0	$0	$0	$0	
Total Revenue Variance	$64	$138	$31	$41	$33	$27	$14	$7	$4	$3	$3	$4	$368

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for USP

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original FTY Budget USP Calculation	$1,213	$2,622	$3,663	$4,788	$3,830	$3,169	$1,622	$788	$421	$362	$374	$519	$23,371
Corrected FTY Budget USP Calculation	$1,188	$2,570	$3,589	$4,692	$3,754	$3,106	$1,589	$772	$413	$355	$367	$508	$22,902
Variance to Original FTY Budget Calculation	($24)	($53)	($73)	($96)	($77)	($64)	($33)	($16)	($8)	($7)	($7)	($10)	($468)
Original FTY Budget USP Rate	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	
FTY USP Rate	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	$0.5770	
USP Rate Variance	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	$0.1077	
Total Rate R Volumes	2,703	5,845	8,163	10,670	8,537	7,065	3,615	1,755	939	807	833	1,156	52,089
Total Rate R excl CAP Volumes	2,532	5,476	7,648	9,997	7,998	6,618	3,387	1,645	880	756	781	1,083	48,801
USP Rate Revenue Variance	$273	$590	$824	$1,077	$861	$713	$365	$177	$95	$81	$84	$117	$5,256
Total Revenue Variance	$248	$537	$750	$981	$785	$649	$332	$161	$86	$74	$77	$106	$4,787

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for GPC

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
GPC Rate FTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FTY Budget	(31)	(66)	(95)	(126)	(100)	(81)	(42)	(22)	(14)	(12)	(13)	(15)	(616)
Revenue Variance	($2)	($4)	($6)	($8)	($7)	($5)	($3)	($1)	($1)	($1)	($1)	($1)	($41)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for STAS

	@ -0.14% Unadjusted 2025 TOTAL	@ -0.13% Adjusted 2025 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (11)	$ (10)	$ 1
Residential-Heating	$ (869)	$ (810)	$ 60
Residential-RT	$ (78)	$ (73)	$ 5
Total R/RT	$ (958)	$ (893)	$ 65
Commercial-Non Htg	$ (12)	$ (11)	$ 1
Commercial- Htg	$ (242)	$ (225)	$ 17
Commercial-NT	$ (89)	$ (83)	$ 6
Industrial	$ (12)	$ (11)	$ 1
Industrial-NT	$ (6)	$ (5)	$ 0
Total N/NT	$ (361)	$ (336)	$ 25
Total DS	$ (49)	$ (37)	$ 12
Total LFD	$ (78)	$ (73)	$ 5
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (1,446)	$ (1,339)	$ 107

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for EEC Rider

	OCT 2024	NOV 2024	DEC 2024	JAN 2025	FEB 2025	MAR 2025	APR 2025	MAY 2025	JUN 2025	JUL 2025	AUG 2025	SEP 2025	TOTAL
Original Budget FTY R/RT Rate	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
FTY R/RT Rate	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	$0.1808	
R/RT Rate Variance	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	($0.0193)	
R/RT Rate Volumes	2,703	5,845	8,163	10,670	8,537	7,065	3,615	1,755	939	807	833	1,156	52,089
R/RT Revenue Adjustment	($52)	($113)	($158)	($206)	($165)	($136)	($70)	($34)	($18)	($16)	($16)	($22)	($1,005)
Original Budget FTY N/NT Rate	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
FTY N/NT Rate	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	$0.0361	
N/NT Rate Variance	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	$0.0084	
N/NT Rate Volumes	1,790	3,611	5,000	6,517	5,226	4,331	2,319	1,270	823	752	766	922	33,327
N/NT Revenue Adjustment	$15	$30	$42	$55	$44	$36	$19	$11	$7	$6	$6	$8	$280
Original Budget FTY DS Rate	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
FTY DS Rate	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	$0.0888	
DS Rate Variance	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	($0.0090)	
DS Rate Volumes	478	799	1,239	1,599	1,436	1,195	693	419	297	257	261	309	8,984
DS Revenue Adjustment	($4)	($7)	($11)	($14)	($13)	($11)	($6)	($4)	($3)	($2)	($2)	($3)	($81)
Original Budget FTY LFD Rate	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
FTY LFD Rate	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	$0.0346	
LFD Rate Variance	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	$0.0297	
LFD Rate Volumes	2,057	2,320	2,612	2,851	2,553	2,455	2,117	1,945	1,796	1,785	1,829	1,869	26,189
LFD Revenue Adjustment	$61	$69	$78	$85	$76	$73	$63	$58	$53	$53	$54	$56	$778
Total Revenue Adjustment	$20	($21)	($49)	($81)	($58)	($38)	$6	$31	$39	$41	$42	$38	($28)

UGI Utilities Inc.- Gas Division
Future Test Year - 12 Months Ended September 30, 2025
($ in Thousands)

Adjustment for DSIC

	@ 4.46% Unadjusted 2025 TOTAL	@ 5% Adjusted 2025 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$253	$284	$31
Residential-Heating	$16,302	$18,276	$1,974
Subtotal Residential-Rate R	$16,555	$18,560	$2,004
Residential-RT	$2,376	$2,664	$288
Total Residential	$18,932	$21,224	$2,292
Commercial-Non Htg	$183	$205	$22
Commercial- Htg	$3,610	$4,047	$437
Subtotal Commercial- Rate N	$3,793	$4,252	$459
Commercial-NT	$2,718	$3,047	$329
Commercial-DS	$1,217	$1,364	$147
Commercial-IS	$412	$462	$50
Commericial-XD-F	$285	$320	$35
Commercial-XD-I	$30	$34	$4
Commercial-LFD	$916	$1,027	$111
Total Commercial	$9,371	$10,506	$1,135
Industrial	$163	$183	$20
Subtotal Industrial- Rate N	$163	$183	$20
Industrial-NT	$178	$200	$22
Industrial-DS	$281	$315	$34
Industrial-IS	$503	$564	$61
Industrial-XD-F	$697	$782	$84
Industrial-XD-I	$59	$66	$7
Industrial-LFD	$1,457	$1,633	$176
Total Industrial	$3,338	$3,743	$404
Grand Total	$31,641	$35,472	$3,831

UGI GAS

EXHIBIT SAE-6(a) – (l)

UGI Utilities Inc.- Gas Division
Historic Test Year 2024 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2024	326,816	1,015,745	703,526	
Adjustment for Customer/Contract Changes	(641)	(5,949)	(4,600)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	11,696	101,563	59,138	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for WNA		(40,911)	(40,911)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for PGC		(16,562)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for MFC		(297)	(297)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for USP		909	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for GPC		522	522	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for Excess Take		(1,615)	(1,615)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for STAS		(15)	(15)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for EEC Rider		127	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(k)
Adjustment for GDE		(3)	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-6(l)
Historic Test Year 2024	337,872	1,053,514	715,748	

UGI Utilities Inc.- Gas Division
Historic Test Year 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	HTY Revenues net of WNA (Unadjusted)	$ 7,816	$ 526,578	$ 51,549	$ 7,258	$ 138,092	$ 6,380	$ 63,154	$ 50,862	$ 123,145	$ 974,834
2	HTY PGC Revenues	$ (1,784)	$ (210,614)	$ (3,711)	$ (3,345)	$ (66,342)	$ (3,332)	$ (391)	(17,239)	(5,462)	(312,219)
3	HTY Revenues net of PGC and WNA - Margin (Unadjusted)	$ 6,032	$ 315,964	$ 47,838	$ 3,913	$ 71,751	$ 3,048	$ 62,763	$ 33,622	$ 117,683	$ 662,614
4	HTY Average Effective Customers (Unadjusted)	21,757	517,734	82,936	3,094	44,682	661	21,337	1,316	987	694,504
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 0.277	$ 0.610	$ 0.577	$ 1.265	$ 1.606	$ 4.611	$ 2.942	$ 25.549	$ 119.233	$ 0.954
6	HTY Customers (Fully Adjusted)	21,199	516,400	79,579	3,088	44,383	667	20,986	1,302	987	688,591
7	Change in Customers during HTY (L6 - L4)	(558)	(1,334)	(3,357)	(6)	(299)	6	(351)	(14)	-	(5,913)
8	Annualization of Margin (L5 * L7)	$ (155)	$ (814)	$ (1,936)	$ (8)	$ (480)	$ 28	$ (1,032)	$ (358)	$ 155	$ (4,600)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4)	$ 0.359	$ 1.017	$ 0.622	$ 2.346	$ 3.091	$ 9.652	$ 2.960	$ 38.649	$ 124.767	$ 1.404
10	Annualization of Total HTY Revenue (L7 * L9)	$ (200)	$ (1,357)	$ (2,087)	$ (14)	$ (924)	$ 58	$ (1,039)	$ (541)	$ 155	$ (5,949)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	$ (46)	$ (543)	$ (150)	$ (6)	$ (444)	$ 30	$ (6)	$ (183)	$ -	$ (1,349)
12	Total HTY UPC (Unadjusted) - MCF	14.90	74.60	70.90	217.10	306.60	1,043.20	646.20	6,821.60		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(8)	(100)	(238)	(1)	(92)	6	(227)	(96)	114	(641)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-6(b)(1)

UGI Utilities Inc.- Gas Division
Historic Test Year - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	HTY Revenues (Unadjusted)	$ 58,682	$ 39,899	$ 2,268	$ 22,295	$ 123,145
2	HTY PGC Revenues	(4,205)	(749)	(47)	(462)	(5,462)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 54,477	$ 39,150	$ 2,221	$ 21,834	$ 117,683
4	HFTY Average Effective Customers (Unadjusted)	614	56	58	259	987
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 88.725	$ 699.111	$ 38.301	$ 84.301	$ 119.233
6	HTY Customers (Fully Adjusted)	622	56	58	251	987
7	Change in Customers during FTY (L6 - L4)	8	-	-	(8)	-
8	Annualization of Margin	$ 572	$ (122)	$ 20	$ (315)	$ 155
9	Average Annual Revenue Per Customer (L1 / L4)	$ 95.573	$ 712.489	$ 39.103	$ 86.083	$ 124.767
10	Annualization of Total FTY Revenue	$ 572	$ (122)	$ 20	$ (315)	$ 155
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	304	(171)	(0)	(20)	114

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	HTY (Unadjusted) Use/Customer ("UPC") - MCF	14.90	74.60	70.90	217.10	306.60	1,043.20	646.20	6,821.60		
2	HTY UPC (Fully Adjusted) - MCF	16.30	89.00	81.90	234.10	316.90	1,235.70	727.50	7,598.10		
3	Change in UPC - MCF (L2 - L1)	1.40	14.40	11.00	17.00	10.30	192.50	81.30	776.50		
4	HTY Customers (Fully Adjusted)	21,199	516,400	79,579	3,088	44,383	667	20,986	1,302	987	688,591
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	30	7,436	875	52	457	128	1,706	1,011	-	11,696
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 320	$ 80,101	$ 5,373	$ 452	$ 3,934	$ 1,105	$ 6,925	$ 3,353		$ 101,563
7	Total Unit Revenue Adjustment (L6 / L5)	$ 10.7719	$ 10.7719	$ 6.1381	$ 8.6056	$ 8.6056	$ 8.6056	$ 4.0588	$ 3.3168	$ -	$ 8.6833
8	Distribution Margin Adjustment (L5 * L9)	$ 154	$ 38,493	$ 4,531	$ 201	$ 1,754	$ 493	$ 6,548	$ 3,095		$ 55,269
9	Distribution Unit Rate	$ 5.1764	$ 5.1764	$ 5.1764	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.8378	$ 3.0611	$ -	
10	PGC Revenue (L5 * L11)	$ 134	$ 33,655		$ 238	$ 2,069	$ 581				$ 36,677
11	PGC Unit Rate	$ 4.5259	$ 4.5259		$ 4.5259	$ 4.5259	$ 4.5259				
12	EE&C Revenue Adjustment (L5 * L13)	$ 6	$ 1,488	$ 175	$ 1	$ 13	$ 4	$ 47	$ 99		$ 1,833
13	EE&C Unit Rate	$ 0.2001	$ 0.2001	$ 0.2001	$ 0.0277	$ 0.0277	$ 0.0277	$ 0.0277	$ 0.0978	$ -	
14	USP Revenue Adjustment (L5 * L15)	$ 14	$ 3,490	$ 411	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,915
15	USP Unit Rate	$ 0.4693	$ 0.4693	$ 0.4693							
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 3	$ 764		$ 1	$ 9	$ 3				$ 780
17	MFC Unit Rate	$ 0.1027	$ 0.1027		$ 0.0199	$ 0.0199	$ 0.0199				
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 9	$ 2,212	$ 256	$ 10	$ 89	$ 25	$ 330	$ 160		$ 3,090
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500		
20	Calculated Total Margin Adjustment (L8 + L16 + L18)	$ 166	$ 41,468	$ 4,787	$ 213	$ 1,852	$ 520	$ 6,878	$ 3,254		$ 59,138
21	Total Unit Margin Adjustment (L20 / L5)	$ 5.5766	$ 5.5766	$ 5.4687	$ 4.0520	$ 4.0520	$ 4.0520	$ 4.0311	$ 3.2190	$ -	$ 5.0561

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for WNA Revenues

			WNA Revenue/Margin
Rate R	Residential-Non Htg	$	(112)
Rate R	Residential-Htg	$	(25,159)
Rate RT	RT	$	(3,630)
Rate N	Commercial-Non Htg	$	(152)
Rate N	Commercial-Htg	$	(6,395)
Rate N	Industrial	$	(313)
Rate NT	NT Total	$	(5,151)
	Total	$	(40,911)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for PGC

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual PGC Rate HTY	$7.5238	$7.5238	$4.3683	$4.3683	$4.3683	$3.9805	$3.9805	$3.9805	$4.5259	$4.5259	$4.5259	$4.5259	
September HTY PGC Rate	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	
PGC Rate Variance	($2.9979)	($2.9979)	$0.1576	$0.1576	$0.1576	$0.5454	$0.5454	$0.5454	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes	2,650	6,606	8,428	11,047	8,875	6,697	3,933	1,689	1,139	1,048	1,073	865	54,050
PGC Revenue Adjustment	($7,944)	($19,805)	$1,328	$1,741	$1,399	$3,653	$2,145	$921	$0	$0	$0	$0	($16,562)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for MFC

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual PGC Rate HTY	$7.5238	$7.5238	$4.3683	$4.3683	$4.3683	$3.9805	$3.9805	$3.9805	$4.5259	$4.5259	$4.5259	$4.5259	
September HTY PGC Rate	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	$4.5259	
PGC Rate Variance	($2.9979)	($2.9979)	$0.1576	$0.1576	$0.1576	$0.5454	$0.5454	$0.5454	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC Volumes-Rate R	1,954	4,838	6,104	7,906	6,387	4,860	2,866	1,229	819	702	733	579	
Total PGC Volumes-Rate N	696	1,768	2,323	3,141	2,488	1,838	1,067	460	320	346	341	286	
Total PGC Volumes	2,650	6,606	8,428	11,047	8,875	6,697	3,933	1,689	1,139	1,048	1,073	865	54,050
Rate R %	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	2.27%	
Rate N %	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	
MFC Rate R Adj Rate	($0.0681)	($0.0681)	$0.0036	$0.0036	$0.0036	$0.0124	$0.0124	$0.0124	$0.0000	$0.0000	$0.0000	$0.0000	
MFC Rate N Adj Rate	($0.0132)	($0.0132)	$0.0007	$0.0007	$0.0007	$0.0024	$0.0024	$0.0024	$0.0000	$0.0000	$0.0000	$0.0000	
Rate R Revenue Variance	($133)	($329)	$22	$28	$23	$60	$35	$15	$0	$0	$0	$0	
Rate N Revenue Variance	($9)	($23)	$2	$2	$2	$4	$3	$1	$0	$0	$0	$0	
Total Revenue Variance	($142)	($353)	$23	$30	$25	$65	$38	$16	$0	$0	$0	$0	($297)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for USP

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual HTY USP Rate	$0.4477	$0.4477	$0.4311	$0.4311	$0.4311	$0.4184	$0.4184	$0.4184	$0.4693	$0.4693	$0.4693	$0.4693	
September HTY USP Rate	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	$0.4693	
USP Rate Variance	$0.0216	$0.0216	$0.0382	$0.0382	$0.0382	$0.0509	$0.0509	$0.0509	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes	2,251	5,586	7,063	9,131	7,348	5,568	3,275	1,406	944	812	838	669	44,889
Total Rate R excl CAP Volumes	2,110	5,237	6,621	8,559	6,886	5,216	3,068	1,317	884	761	785	627	42,071
USP Rate Revenue Variance	$46	$113	$143	$185	$149	$113	$66	$28	$19	$16	$17	$14	$909
Total Revenue Variance	$46	$113	$143	$185	$149	$113	$66	$28	$19	$16	$17	$14	$909

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for GPC

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
GPC Rate HTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to HTY	405	972	1,226	1,581	1,279	977	582	260	178	158	159	130	7,909
Revenue Variance	$27	$64	$81	$104	$84	$65	$38	$17	$12	$10	$11	$9	$522

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(269)
$/MCF		$6.00
Excess Take Revenue/Margin	$	(1,615)

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for STAS

	Unadjusted 2024 TOTAL	Adjusted 2024 TOTAL	Revenue Adjustment Total
Residential-Non Htg	$ (7)	$ (7)	$ (0)
Residential-Heating	$ (467)	$ (476)	$ (9)
Residential-RT	$ (47)	$ (48)	$ (1)
Total R/RT	$ (521)	$ (531)	$ (10)
Commercial-Non Htg	$ (6)	$ (6)	$ (0)
Commercial- Htg	$ (123)	$ (126)	$ (2)
Commercial-NT	$ (55)	$ (56)	$ (1)
Industrial	$ (6)	$ (6)	$ (0)
Industrial-NT	$ (3)	$ (4)	$ (0)
Total N/NT	$ (194)	$ (197)	$ (3)
Total DS	$ (42)	$ (43)	$ (1)
Total LFD	$ (49)	$ (49)	$ (1)
Total XD-F	$ -	$ -	$ -
Total Interruptible	$ -	$ -	$ -
Grand Total	$ (806)	$ (821)	$ (15)

UGI Utilities Inc.- Gas Division
Historic Test Year - 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for EEC Rider

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Original Budget FTY R/RT Rate	$0.1625	$0.1625	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
FTY R/RT Rate	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	$0.2001	
R/RT Rate Variance	$0.0376	$0.0376	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
R/RT Rate Volumes	2,251	5,586	7,063	9,131	7,348	5,568	3,275	1,406	944	812	838	669	44,889
R/RT Revenue Adjustment	$85	$210	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$295
Original Budget FTY N/NT Rate	$0.0316	$0.0316	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
FTY N/NT Rate	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	$0.0277	
N/NT Rate Variance	($0.0039)	($0.0039)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
N/NT Rate Volumes	1,490	3,328	4,199	5,696	4,531	3,399	2,114	1,032	811	806	789	653	28,849
N/NT Revenue Adjustment	($6)	($13)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($19)
Original Budget FTY DS Rate	$0.0474	$0.0474	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
FTY DS Rate	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	$0.0978	
DS Rate Variance	$0.0504	$0.0504	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	511	1,252	1,162	1,465	1,206	963	704	411	316	315	328	345	8,978
DS Revenue Adjustment	$26	$63	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$89
Original Budget FTY LFD Rate	$0.0632	$0.0632	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
FTY LFD Rate	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	$0.0049	
LFD Rate Variance	($0.0583)	($0.0583)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,855	2,219	2,334	2,789	2,478	2,275	1,961	1,683	1,485	1,461	1,586	1,549	23,675
LFD Revenue Adjustment	($108)	($129)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($238)
Total Revenue Adjustment	($4)	$131	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$127

UGI Utilities Inc.- Gas Division
Historic Test Year- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for GDE Rider

	OCT 2023	NOV 2023	DEC 2023	JAN 2024	FEB 2024	MAR 2024	APR 2024	MAY 2024	JUN 2024	JUL 2024	AUG 2024	SEP 2024	TOTAL
Actual HTY DS Rate	$0.0060	$0.0060	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
September HTY DS Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
DS Rate Variance	($0.0005)	($0.0005)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	511	1,252	1,162	1,465	1,206	963	704	411	316	315	328	345	8,978
DS Revenue Adjustment	($0)	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)
Actual HTY LFD Rate	$0.0060	$0.0060	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
September HTY LFD Rate	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	$0.0055	
LFD Rate Variance	($0.0005)	($0.0005)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,855	2,219	2,334	2,789	2,478	2,275	1,961	1,683	1,485	1,461	1,586	1,549	23,675
LFD Revenue Adjustment	($1)	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)
Total Revenue Adjustment	($1)	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)

UGI GAS

EXHIBIT SAE-7(a) – (c)

Detail for Usage per Customer for FPFTY by Class as shown on UGI Gas Exhibit SAE-4(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.4	23,634	387,598
Rate R	16.3	19,875	323,319
Rate RT	17.1	3,759	64,279

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	88.2	604,631	53,328,454
Rate R	88.7	526,965	46,726,844
Rate RT	85.0	77,666	6,601,610
Rate RT Total	81.9	81,425	6,665,889

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	410.1	4,474	1,834,787
Rate N	249.7	2,905	725,429
Rate NT	622.0	1,545	960,990
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	552.0	65,074	35,920,848
Rate N	340.2	44,718	15,214,480
Rate NT	703.3	19,240	13,531,492
Rate DS	6,429.1	1,116	7,174,876
Rate Commercial NT Total	697.3	20,785	14,492,482

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,542.6	1,252	3,183,335
Rate N	905.4	596	539,625
Rate NT	2,085.5	466	971,843
Rate DS	8,799.3	190	1,671,867
Rate NT Total	727.7	21,251	15,464,325
Rate DS Total	6,763.2	1,330	8,995,111

Detail for Usage per Customer for FTY by Class as shown on UGI Gas Exhibit SAE-5(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	16.4	24,181	396,568
Rate R	16.3	20,422	332,290
Rate RT	17.1	3,759	64,279

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	88.4	598,421	52,900,416
Rate R	88.9	520,755	46,298,806
Rate RT	85.0	77,666	6,601,610

Rate RT Total	81.9	81,425	6,665,889

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	410.1	4,547	1,864,725
Rate N	253.6	2,978	755,367
Rate NT	622.0	1,545	960,990
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	552.0	64,902	35,825,904
Rate N	339.7	44,547	15,131,875
Rate NT	703.3	19,240	13,531,492
Rate DS	6,423.8	1,115	7,162,537

Rate Commercial NT Total	697.3	20,785	14,492,482

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Fully Adj Sales
Total	2,542.6	1,280	3,254,528
Rate N	978.4	624	610,552
Rate NT	2,085.5	466	971,843
Rate DS	8,800.7	190	1,672,133

Rate NT Total	727.7	21,251	15,464,325
Rate DS Total	6,759.2	1,329	8,983,038

Detail for Usage per Customer for HTY by Class as shown on UGI Gas Exhibit SAE-6(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.4	24,851	407,556
Rate R	16.3	21,169	344,594
Rate RT	17.1	3,682	62,962

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	88.5	592,297	52,418,285
Rate R	89.0	516,400	45,967,040
Rate RT	85.0	75,897	6,451,245
Rate RT Total	81.9	79,579	6,514,207

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	410.1	4,619	1,894,252
Rate N	234.1	3,076	720,197
Rate NT	622.0	1,522	946,684
Rate DS	10,827.2	21	227,371

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	552.0	64,510	35,609,520
Rate N	316.9	44,383	14,066,457
Rate NT	703.3	19,007	13,367,623
Rate DS	7,299.5	1,120	8,175,440
Rate Commercial NT Total	697.3	20,529	14,314,307

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,542.6	1,285	3,267,241
Rate N	1,235.7	667	824,225
Rate NT	2,085.5	457	953,074
Rate DS	9,254.3	161	1,489,942
Rate NT Total	727.5	20,986	15,267,381
Rate DS Total	7,598.1	1,302	9,892,754

UGI GAS

EXHIBIT SAE-8

UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation

Notes:

1/ Storage Trip Cost ($/mcf) 0.1460

2/ Weekend Load Reduction Factor (%) 15.2%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 **WD = (1/(1 - WELF)) * WE**
= (1/(1 - 0.15)) * WE
WD = 1.18 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7**
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.15)) + 2] * WE] / 7
7.90 * WE / 7
Step 2 WE = 0.89 * AVERAGE

4/ EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE)
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) - 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.15)) - 2) * WE] - (3 * AVERAGE)
3.90 * WE - (3 * AVERAGE)
0.47 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.47 x Average) / (7 x AVERAGE)] x 0.133
0.07 x 0.146
0.0102

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0102 x 20
0.2040

Notes:

1/ Weighted average of storage trip costs based on SCQ of storages
2/ Aggregate load reduction for all non-Choice transportation customers electing NNS
Weekend Load Reduction factor percentage based on historical data for the period Oct 2023 through Sep 2024
3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days
4/ Assumes levelized deliveries on all days

UGI GAS

EXHIBIT SAE-9

UGI Utilities, Inc. - Gas Division
Monthly Balancing Service (MBS) Rate Calculation

Notes:

1/	Average Capacity Charge for Storage ($/mcf)	1.3070	(A)
2/	Anticipated Average Monthly Imbalance %	0.6786%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.2%	(C)
LFD	57.7%	(C)
XD Firm	57.3%	(C)
Transportation System Average	50.6%	(D)

MBS Rate Formula
E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0128	(E)
LFD	0.0074	(E)
XD Firm	0.0075	(E)

1/ Weighted average of storage capacity and demand costs based on SCQ of storages
2/ Average monthly imbalance percentage includes all non-Choice transportation customers electing MBS
Average monthly imbalance percentage based on historical data for the period Oct 2023 through Sep 2024
3/ Load Factors based on FPFTY throughput and peak capacity for applicable customers by rate class

UGI GAS

EXHIBIT SAE-10

UGI Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

			Rate R/RT	Rate N/NT
Total Uncollectible Revenue Requirement	$	22,245,065		
Allocator 1/			92.92%	6.96%
Uncollectible Revenue Requirement			$ 20,670,114	$ 1,548,257
Total Proposed Revenue			$ 806,644,967	$ 275,340,828
MFC % 2/			2.56%	0.56%

1/ The allocator is based on a 3-year average of uncollectible expenses.
2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS STATEMENT NO. 9

CHRISTOPHER R. BROWN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. - Gas Division

Statement No. 9

Direct Testimony of
Christopher R. Brown

Topics Addressed:	**Natural Gas Operations** **Regulatory Compliance** **System Safety and Reliability** **Leak Reductions & Emergency Response** **Safety Initiatives** **Environmental Programs**

Dated: January 27, 2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed as the Vice President of Operations by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two (2) operating divisions, the Gas Division ("UGI Gas" or the "Company) and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

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

Q. What are your responsibilities as Vice President of Operations?

A. As Vice President – Operations, I am UGI's senior executive accountable for approximately 830 individuals including management, clerical, and field technicians that operate and maintain the Company's gas transmission and distribution system. I am also responsible for overseeing activities and personnel involved with the Company's capital planning department, buildings and grounds, fleet, physical security, and business continuity programs.

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

A. Yes. UGI Gas Exhibit CRB-1 identifies my prior testimony.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the following topics: (1) natural gas system operations; (2) regulatory compliance; (3) system safety and reliability; (4) leak reductions and emergency response; (5) safety initiatives; and (6) environmental programs. Within these topics, I support several adjustments related to the Company's claim, specifically related to: (1) leak surveys; (2) pipeline material verification; and (3) pipeline contractor price increases.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibit CRB-1.

II. NATURAL GAS SYSTEM OPERATIONS

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

A. UGI Gas provides service to approximately 700,000 residential, commercial, and industrial customers located in 45 of Pennsylvania's 67 counties and spanning more than 700 municipalities. As of September 30, 2024, the Company operates more than 12,000 miles of gas distribution mains and 300 miles of natural gas transmission mains in the Commonwealth of Pennsylvania.

Q. Please describe UGI Gas's operations centers and support facilities.

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

Q. How does UGI Gas staff its operations?

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

Q. As related to the use of contractor resources, has UGI Gas seen an increase in the pipeline construction costs since its budget was finalized?

A. Yes, late in 2024, UGI Gas received the results from its request for proposal ("RFP") for pipeline construction and maintenance, contained within a Master Pipeline Construction Agreement ("MPCA") (the "2025 RFP"). The results of the 2025 RFP reflect an expected increase of 17.5% over the expense base budget amount of $9.196 million (base budget reflects no pricing change).

Q. Please describe the Company's use of contractors for its main replacement and other maintenance activities.

A. UGI Gas utilizes contractor resources to perform construction and maintenance activities on the natural gas distribution system, including main and service line replacement, valve inspections, leak repairs, spotting facilities, corrosion mitigation, traffic control, sidewalk and roadway restoration, and others.

Q. How are contractors selected to perform work at UGI Gas?

A. UGI Gas utilizes a competitive bid process, typically on a three-year cycle, and awards blanket style construction agreements to multiple incumbent and incremental contractors who bid on each region within the Company's service territory. The contracts are awarded based on key factors of price, capability, and safety record. Using this process, UGI Gas was successful in maintaining consistent costs for a majority of the pipeline construction contractors from 2022 until the most recent RFP in which pricing will become effective on March 1, 2025.

Q. Please describe the 2025 RFP process.

A. UGI Gas typically uses three-year contract terms for its blanket construction contractors. The table below shows the critical date for the 2025 RFP impacting contractor costs in this proceeding:

Table 1: Critical Dates for the 2025 RFP

Category	Contract	RFP Issued	Contract Effective	Contract Expiration
Pipeline/Construction	MPCA	7/24/2024	3/1/2025	2/29/2028

Q. Please describe the results of the 2025 RFP.

A. The results of the 2025 RFP reflect price increases across the range of services provided by the bidders. As intended, UGI Gas was successful in attracting several additional contractor bids throughout the various bid regions established within these contracts. RFPs were sent to 29 contractors (including 16 who were not currently under a blanket contract with UGI Gas), and 22 contractors responded with a bid, indicating a competitive market.

Q. What is driving the increase in prices reflected in the RFP results?

A. The pipeline construction labor market is constrained. To secure skilled labor, contractors must pay higher labor rates, and those higher rates are passed on to UGI Gas. In addition, the scope of units included in the contract includes more work than the previous contract. For example, a contractor is now required to collect certain installed distribution asset data that previously was not required, resulting in longer times to complete a similar number of units of work. This is just one example where the requirements within the Company's Gas Operations Manual ("GOM") have increased since the last contract negotiation, and contractors are reflecting the cost to comply with these requirements in their bids.

Q. Have you quantified the impact of the increased contractor costs on the operating expense claim for the FPFTY?

A. Yes, the Company has quantified the impact of the increased contractor costs on its operating expense claim, as shown on Schedule D-18 of UGI Gas Exhibit A – Fully Projected. As shown on Schedule D-18, UGI Gas's budget for pipeline contractor expense in this case for the FPFTY was $10.116 million, with this amount being inclusive of an estimated increase in contractor cost of 10% to address cost increases that would likely result from the RFP process described above. However, the actual increase realized through the RFP process was 17.5%, bringing the total contractor costs for the FPFTY to $10.803 million. Accordingly, a proforma adjustment of $687,000 ($10.803-$10.116) is included to reflect these known incremental cost increases for the FPFTY, as shown on Line 4 of Schedule D-18.

III. <u>REGULATORY COMPLIANCE</u>

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

A. UGI Gas is subject to the minimum federal pipeline safety regulations in 49 CFR § 192 - Transportation of Natural and Other Gas by Pipeline ("Part 192"). The Company must also follow the applicable state pipeline safety requirements found in Pennsylvania Title 52, Chapter 59 - Gas Service and Hazardous Liquid Service ("Chapter 59"). Pennsylvania natural gas pipeline safety regulations found in Chapter 59 of the Commission's regulations generally follow the Part 192 regulations.

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

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

- Design & Construction Standards
- Operation & Maintenance Procedures
- Emergency Plans
- Integrity Management Plans
- Damage Prevention Plans
- Public Awareness Programs
- Control Room Management Plans

Q. How has the Company complied with these regulations?

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

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

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

- Pipeline Leak Surveys and Patrols
- Valve Maintenance and Inspection
- Regulator Station Inspection and Maintenance

- Service Line Leak Survey and Meter Inspection
- Atmospheric Corrosion Inspection
- Cathodic Protection Inspection and Maintenance
- Odorant Intensity Inspection
- Transmission Integrity Management Assessments

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

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

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

In other situations, UGI Gas has elected to implement other voluntary actions that arise from national events or recommendations by the National Transportation Safety Board ("NTSB") and other governmental agencies. As an example, following over-pressurization prevention guidance issued by the NTSB in 2019, UGI Gas evaluated the over-pressurization protection ("OPP") utilized on its low-pressure systems. A total of 73 regulator stations serving over 80,000 customers required supplemental OPP to implement the NTSB's recommendations on OPP. The supplemental OPP recommended by the NTSB exceeded the minimum requirements specified in Part 192. UGI Gas implemented a plan to address supplemental OPP at all 73 stations. As of September 30, 2024, 72 of the 73 stations have been addressed through the installation of supplemental OPP, station abandonment, or regulator station replacement. These projects were prioritized on a risk reduction basis seeking to maximize the customers served by regulator stations that included the supplemental OPP. The final station, which provides service to the last approximately 150 customers of the 80,000 total customers, is expected to meet the NTSB recommendations on OPP by September 30, 2025, which will complete the OPP enhancement program.

Q. Does the Company have integrity management plans?

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

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

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

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

A. Yes, UGI Gas maintains an Operator Qualification Plan ("OQ Plan") complying with the requirements of 49 CFR § 192, Subpart N. The OQ Plan establishes requirements for and management of qualifications for pipeline personnel who perform covered tasks on a pipeline. UGI Gas's OQ Plan includes over 145 unique covered tasks. Pipeline personnel are trained and qualified under the tasks needed to perform their various work activities on a UGI Gas pipeline. Covered tasks ensure internal and external pipeline personnel are educated, tested, and competent to perform specific natural gas activities on UGI Gas's distribution system.

Q. Are revisions made to the federal regulations found in Part 192?

A. Yes, periodically the Pipeline and Hazardous Material Safety Administration ("PHMSA") issues notices of proposed and final rulemakings that inform natural gas pipeline operators of proposed and final revisions made to federal regulations. A list of recent PHMSA rulemakings and their status are available publicly online. Rulemakings generally takes months to years to complete depending on the extent of the proposed revisions.

Q. What impacts do revisions to federal regulations pose to the Company?

A. Recently, PHMSA proposed and adopted substantial revisions to the federal regulations, which significantly affected the Company. As an example, PHMSA promulgated a rulemaking titled "Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure ("MAOP") Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" ("Gas Transmission Final Rule") published in the Federal Register on October 1, 2019, with an effective date of July 1, 2020. This rulemaking was arguably the single largest change to natural gas transmission pipeline safety regulations since Part 192 was originally published in 1970. More specifically, two new regulations out of many revisions were introduced under Title 49:

- § 192.607 - Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.
- § 192.624 - MAOP reconfirmation: Onshore steel transmission pipelines.

These new regulations require UGI Gas to reconfirm the MAOP and, when applicable, material specifications of transmission pipelines that do not have a traceable, verifiable, and complete MAOP records. Accordingly, UGI Gas reviewed its records and documentation pertaining to all its transmission assets and created a schedule in accordance with the MAOP reconfirmation timelines specified under 49 CFR § 192.624.

PHMSA also proposed rulemakings regarding Leak Detection and Repair ("LDAR") and Safety of Gas Distribution Pipelines, which are still not finalized and published in Part 192. These are extensive changes (as described further herein) to the current federal regulations and would require UGI Gas to increase financial and labor resources to comply with the proposals. The Company continues to closely monitor the status of all proposed PHMSA rulemakings as well as other agencies, such as the U.S. Environmental Protection Agency ("EPA") and the Occupational Safety and Health Administration ("OSHA").

Q. Please discuss UGI Gas's Material Verification Plan.

A. UGI Gas has a formal Material Verification ("MV") Plan as part of its TIMP that outlines the procedures and requirements to meet the MV requirements in federal code under 49 CFR § 192.607. The verification of material properties and attributes for transmission pipelines is required when an operator does not have traceable, verifiable, and complete ("TVC") records. Federal code stipulates that for pipeline populations (segments of pipe that have the same material characteristics such as wall thickness, grade, manufacturing process and dates, and construction dates), MV must occur at a minimum of one excavation per mile along the pipeline.

UGI Gas's MV Plan defines what pipeline segments require MV, which includes pipeline segments that have missing or incomplete TVC pressure test data needed for MAOP reconfirmation. UGI Gas has also committed to voluntarily gather material and component attributes on an opportunistic basis for all other transmission pipeline segments without TVC records to provide material attributes for anomaly repairs, Engineering Critical Assessments, and predicted failure pressure calculations.

Q. How many pipeline segments does UGI Gas have in the MV Plan?

A. UGI Gas has identified 36 transmission pipelines that have segments that need material verification. Since August 2020, UGI Gas has completed 87 MV tests (approximately 22 per year) based primarily on opportunistic excavations, which are those related to other pipeline activities. UGI Gas has an estimated 323 MV tests remaining, which can be reduced to 262 MV tests, if the Company accounts for anticipated bare steel main replacements planned to occur before the applicable reconfirmation timelines, thereby eliminating the need to perform MV. The MV process requires technical expertise and equipment. Historically, costs for targeted MV tests including labor, materials, and overhead have averaged near $38,000 per test. These costs have historically been treated as expense items.

Q. How will UGI Gas accelerate its MV Plan?

A. UGI Gas anticipates that as material verification is completed for certain pipeline segments, future opportunistic excavations will be limited based on the remaining required segment population. In other words, UGI Gas will need to proactively plan and execute on MV activities to complete the work. UGI Gas will strategically target specific pipeline populations. Starting in Fiscal Year 2026, UGI Gas will increase the number of material verifications to an average target of 35 per year, which will allow for a targeted completion by Fiscal Year 2032. These annual MV targets will include a combination of opportunistic and strategic approaches. The additional 13 MVs over the historic yearly average of 22 will cost an additional estimated $494,000 per year over the current program and is included in Schedule D-17 of UGI Gas Exhibit A – Fully Projected. This will allow UGI Gas to complete its MV Plan for transmission pipelines and stay in compliance with MAOP reconfirmation timelines.

IV. SYSTEM RELIABILITY AND SAFETY

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

A. Due to its long-term operation, the Company's distribution system includes a mixture of pipeline materials indicative of the industry's technological advancement over time. Cast iron mains can be found in the oldest parts of the initial system. UGI Gas, and the industry in general, then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include polyethylene ("PE") and coated steel piping. Overall, approximately ninety percent (90%) of UGI Gas's distribution mains consist of contemporary materials, which UGI Gas defines as cathodically protected steel and modern plastic. UGI Gas's natural gas distribution system has the highest percentage of contemporary mains among major natural gas distribution companies in Pennsylvania.

Q. Please discuss the Company's actions to improve and enhance its distribution system.

A. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis through Commission-approved Long Term

Infrastructure Improvement Plans ("LTIIP"). The Company's Initial LTIIP[1] and Second LTIIP[2] have resulted in UGI Gas successfully removing more than 730 miles of main over the 11-year period from 2014 to 2024, including ninety-three percent (93%) of its total cast iron mains and forty-three percent (43%) of its total bare steel/wrought iron mains.

UGI Gas will continue to invest in improving and modernizing its distribution facilities serving customers throughout the Company's service territory. The Company filed its Third LTIIP in August 2024, and this plan was approved by the Commission on December 5, 2024, at Docket No. P-2024-3050769. The Third LTIIP includes the replacement of another 310-340 total miles of cast iron, bare steel, wrought iron, and priority plastic main during the 5-year LTIIP period. In addition to main replacements in the Third LTIIP, the Company is pursuing other infrastructure initiatives including replacing service lines, meter sets, valves, farm taps, as well as addressing safety upgrades relating to measurement and regulation facilities (e.g., making improvements to over-pressure protection equipment) and remediating mechanical tees. Additionally, the Company outlined a plan for replacement of priority plastic, which includes plastic installed between 1965 and 1985. These initiatives will make UGI Gas's system safer and more reliable. Continuing UGI Gas's infrastructure replacement program will allow the Company to provide safe and reliable service both now and into the future.

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[1] On December 12, 2013, each of UGI Gas's three predecessor natural gas distribution companies filed Petitions, and received Commission approval, for LTIIPs at Docket Nos. P-2013-2398833, P-2013-2397056, and P-2013-2398835 (collectively referred to as the "Initial LTIIP"). In the Initial LTIIP, the Company identified its plan to replace all its cast iron main over the 13-year period ending in February 2027 and all of its bare steel and wrought iron main over the 28-year period ending September 2041. The Initial LTIIP period ended on December 31, 2019.

[2] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Petition filed on August 21, 2019) (the "Second LTIIP"). The Second LTIIP builds off the significant acceleration in the rate of infrastructure repairs, improvements, and replacements (including the accelerated replacement of cast iron and bare steel pipe) that was achieved by the Initial LTIIP and reflects even further acceleration.

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

A. In 2019, UGI Gas began using the Data-Driven risk model ("DDRM"). The DDRM is a quantitative model incorporating leak repair data, incident data, and asset population data to calculate a risk index score for facility groupings referred to as Asset Threat Groups ("ATGs"). The DDRM is utilized in conjunction with the Subject Matter Expert ("SME") driven risk model in order to validate DDRM results by incorporating SME input. Optimain, a risk evaluation software tool, also continues to be utilized to evaluate risk on an individualized main segment level and assists in validating DDRM outputs for cast iron and steel mains.

The DDRM provides a quantitative basis for evaluating risk and creates a stable foundation for comparing year-over-year changes because of the consistent quantitative underpinning utilized. Finally, the DDRM helps UGI Gas better evaluate other effective approaches for addressing risk, including effective operations and maintenance programs, additional leak survey activities and damage prevention measures.

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

A. UGI Gas is on track to replace all its cast iron main no later than February 2027, consistent with its initial completion plan and prior commitments. Further, the Company plans to complete its bare steel and wrought iron main replacement no later than September 2041, also consistent with its initial completion plan. Specifically, to maintain a pace of replacement that would achieve these objectives, the Company's Third LTIIP established the objective of replacing between 50 and 60 miles of main in calendar year 2025, and between 60 to 70 miles of main per year in calendar years 2026 - 2029. An additional 15 miles of wrought iron and bare steel are planned to be replaced in calendar year 2027 due to corrosion.

Q. Did UGI Gas achieve its mileage objective in the first four years of its Second LTIIP?

A. Yes, the Company achieved and exceeded its mileage objective, by replacing or retiring over 295 miles of main in 2020 through 2023.

Q. What is UGI Gas's projection of its replacement and betterment plant in service for the future test year ("FTY") and the fully projected future test year ("FPFTY")?

A. For the FTY, the replacement and betterment budget reflects $315.5 million plant in service. The FPFTY plant placed in service for replacement and betterment is budgeted to be $327.8 million. For more detail on the Company's budgeting process related to all planned capital activities, please refer to the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

Q. What is the Company's basis for showing a further increase in plant placed in service in the FTY and FPFTY?

A. Foremost, the Company's annual plant additions related to replacement and betterment activities increased nearly $70 million over the 2020-2024 period, from $306 million in 2020 to $376 million in 2024. The Company anticipates that the cost of its replacement and betterment work will continue to increase through the FPFTY due to a number of different elements. First, the Company is further accelerating the number of miles it will accomplish in the FTY and FPFTY. In addition, these miles of main include large portions of the remaining cast iron main replacement projects, which are planned to be completed by 2027, and consist of projects featuring increased complexity, challenging locations, and in many cases larger diameter pipes. Additionally, the cost of contractor labor to complete this work is continuing to increase. For these reasons, UGI Gas's budget for the FTY and the FPFTY reflects increased plant additions beyond the amount that the Company had accomplished during the HTY.

Q. What other system reliability improvements has the Company performed recently?

A. In addition to pipeline replacement, the Company's Third LTIIP includes a project related to natural gas system over pressure protection ("OPP") as discussed above. UGI Gas also recently completed an implementation plan to add remote pressure monitoring capabilities to its low-pressure systems. These capabilities include real-time alarm notifications to allow expedited system pressure correction and adjustment. As of September 30, 2024, all remote pressure monitoring deployment was completed.

Additionally, UGI Gas completed pressure reinforcement projects in the Jersey Shore, Macungie, and Wyomissing areas of its service territory within the last two years. Finally, the Company completed significant improvements to four city gate stations as well as two district regulator stations.

V. LEAK REDUCTIONS AND EMERGENCY RESPONSE

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

A. UGI Gas monitors safety and reliability indicators for its natural gas distribution system on an ongoing basis to evaluate corrosion and leak identification and resolution performance, track emergency response, and pursue damage prevention – all of which will drive improvements in employee and public safety. As a part of its DIMP,[3] UGI Gas regularly re-assesses system risks and leak trends to determine if additional or accelerated actions are required to further reduce system leaks.

Leak surveys are an important tool for discovering, monitoring, and remediating leaks. To enhance its leak identification capabilities, UGI Gas is currently working to finish evaluation of Advanced Mobile Leak Detection ("AMLD") technology, including completed pilot surveys in 2024 to discover leaks on mains and adjacent service lines. AMLD is a recent development in methane detection technology that offers higher methane detection sensitivities when compared to traditional leak survey technologies that the Company employs. AMLD involves the collection of various data points while performing a mobile leak survey; once data is collected, a list of prioritized leak indications is generated for the Company to review and investigate. AMLD technologies incorporate methane detection capabilities in parts per billion (ppb) which provides highly precise data that is 1,000 times more sensitive than most leak detection sensors currently available. AMLD technologies allow natural gas leak plume data to be collected and interpreted from a distance and at a speed and scale not previously possible.

An additional benefit of the AMLD technology is the ability to quantify methane emissions associated with UGI Gas's distribution system. AMLD technology can measure large volume leaks, over 10 standard cubic feet per hour (scfh), allowing UGI Gas to prioritize leaks that are a hazard to the environment. Methane emission quantification also allows for the highest-emitting leaks to be identified and targeted for expedited repair or replacement. This technology is a more efficient method that may be used to identify

[3] 49 C.F.R. § 192.1007.

methane emission sources over a greater number of miles in a more rapid and cost effective manner than traditional survey methods.

This work by UGI Gas is of particular importance as PHMSA is proposing significant regulatory revisions within its proposed LDAR rulemaking, which is anticipated to become final in early 2025. Significant changes to leakage survey and patrolling requirements, performance standards for advanced leak detection programs, enhanced leak survey frequencies for vintage plastic mains, and several other revisions to Part 192 are part of this rulemaking. These newly proposed regulatory requirements regarding leak detection and repair will have significant impacts to UGI Gas's operating expenditures. When finalized, the new rules will introduce more frequent leak survey frequencies for most transmission and distribution asset mains and service lines. With the increase in leak survey frequency requirements and use of new advanced leak detection technologies, UGI Gas will be positioned to detect, classify, and schedule for repairing natural gas leaks in a more proactive manner, while giving further considerations to environmental risk factors, consistent with the new rules.

Q. What impact will these new LDAR requirements have on the Company's claimed costs in this proceeding?

A. The incremental cost related to compliance with the new LDAR rules was not included in the Company's budget for the FPFTY period. Accordingly, the table below summarizes the estimated annual cost impact that UGI Gas anticipates based upon these new LDAR federal requirements for accelerated leak surveys of transmission and distribution mains.

These amounts are reflected as an adjustment, Adjustment #1, in Schedule D-13 of UGI Gas Exhibit A (Fully Projected).

Table 2: Transmission & Distribution Line Surveys

Description	Annual OPEX Cost
Transmission Line Leak Surveys & Patrols	$ 1,531,607.40
Distribution Line Leak Surveys	$ 328,898.61

Q. Are there other leak survey impacts related to the LDAR rules which UGI Gas is implementing?

A. Yes, the required leak survey frequency for priority plastic is increased as part of the rulemaking. Priority plastic installed in the UGI Gas system contains DuPont Aldyl A plastic pipe, which can be susceptible to failures over time dependent upon local environmental conditions and installation practices. Aldyl A has long been documented by the natural gas industry as susceptible to early failures and has been highlighted in the Commission's recent Tentative Order.[4] The total length of priority plastic mains installed on UGI Gas's distribution system between the years of 1965 and 1985 is approximately 1,100 miles. Current leak survey frequencies for this asset population are generally on a 5-year cycle in line with federal regulations, although UGI Gas typically performs these surveys on a 4-year cycle. UGI Gas is proposing to perform annual leak surveys on this asset population beginning in Fiscal Year 2026. This proposed leak survey frequency is consistent with the proposed frequency in PHMSA's LDAR rulemaking. Regardless of the pending LDAR rule, UGI Gas is moving forward with making this survey frequency

[4] See *Replacement of Older Plastic Pipe in Natural Gas Distribution Systems*, Docket No. M-2024-3050313 (Tentative Order entered Aug. 26, 2024).

change in recognition of the need to increase monitoring and data collection on priority plastic assets. The expansion of leak surveys on the Company's priority plastic main population will provide additional safety checks to detect any leaks or failures more proactively. Importantly, this data feeds into the Company's DIMP for evaluation, risk ranking, and replacement prioritization.

Q. What impact will the increase in vintage plastic leak survey frequency have on the Company's claimed costs in this proceeding?

A. The incremental cost related to moving to annual surveys for vintage plastic assets is estimated at $200,000. This amount is reflected as an adjustment, Adjustment #2, in Schedule D-13 of UGI Gas Exhibit A (Fully Projected).

Q. How has the Company implemented AMLD Technology to date?

A. UGI Gas began its initial pilot of AMLD in 2021. The Company purchased one AMLD device and subsequently installed it on a Company vehicle. During the initial phase, the vehicle was driven along 445 miles of main in the Northern district. In subsequent years, UGI Gas continued to pilot this unit and other competing AMLD technologies within its service territory to aid in the analysis and development of its AMLD program. AMLD technology allowed UGI Gas to perform mobile main-line leak survey at speeds five to 10 times greater than traditional main line survey. A variety of distribution materials were included within these survey pilots, such as bare steel, coated steel, and various vintages of plastic to better understand each populations' emission rates. When leaks were detected through AMLD, they were investigated using traditional leak survey methods to ensure current compliance with internal and regulatory standards. Through this entire process, UGI Gas was able to analyze the full range of capabilities AMLD can offer to the Company.

Q. What are UGI Gas's long-term plans for AMLD Technology?

A. UGI Gas will leverage the AMLD vehicle in Fiscal Year 2025 to continue quantifying methane emission rates in targeted geographic areas of UGI Gas's distribution system. The Company will also finalize its processes and resources related to AMLD technology for the full integration of AMLD technology into UGI Gas's leak detection program.

Beyond Fiscal Year 2025, UGI Gas is proposing to utilize AMLD technology on 20% of its drivable mains annually in addition to the Company's traditional leak survey schedule for mains and service lines in compliance with all current standards and federal regulations. The Company's AMLD plan will quantify the emission rates of its entire distribution system within five years. This new proposed survey cycle will add meaningful data points regarding the Company's mains and service lines while identifying new environmental risk reduction opportunities not otherwise afforded to UGI Gas. This information will also be leveraged within UGI Gas's DIMP to provide additional information and knowledge to the asset populations contained within the DIMP.

UGI Gas will leverage this technology to quantify methane emissions from transmission and distribution pipelines owned and operated by UGI Gas. With the increase in leak survey frequencies, UGI Gas will be better positioned to detect, classify, and schedule the repair of natural gas leaks in a proactive manner while providing further considerations to environmental risk factors.

Q. Does the use of AMLD technology align with the anticipated finalized PHMSA LDAR rules?

A. Yes. UGI Gas's leak detection program which continues to pilot AMLD technology, aligns with PHMSA's proposed regulations. It is important that UGI Gas continue expanding its efforts not only to position itself for compliance with PHMSA's proposed regulations, but also to recognize that the AMLD technology benefits the Company, its customers, and the public by improving system safety and reliability and reducing greenhouse gas emissions.

Q. What are the expected annual operating costs of UGI Gas's AMLD plan?

A. UGI Gas expects the annual financial operating expenditures to be approximately $1.7 million based upon the 5-year proposed frequency rate. This cost was based upon the piloted use of UGI Gas's AMLD vehicle as well as the additional costs associated with new leak indications that UGI Gas would expect to encounter and investigate.

Q: Have the increased costs for AMLD been included within the Company's claim in this proceeding?

A: Yes, these incremental costs are reflected as an adjustment, Adjustment #3, as shown on Schedule D-13 of UGI Gas Exhibit A (Fully Projected).

Q. How does UGI Gas classify leaks?

A. UGI Gas uses a standardized leak classification system consistent with general industry protocols. Specifically, underground leaks are classified as 'A,' 'B,' and 'C.' Class 'C' leaks are deemed hazardous and repair work is undertaken immediately. Class 'B' leaks are non-hazardous at the time of detection but justify a scheduled repair. Pursuant to UGI Gas's practice, Class 'B' leaks must be repaired or cleared within one calendar year, but no later than 15 months from the date of the latest Class 'B' leak classification. UGI Gas has been focused on continuous improvement for Class 'B' leak repairs. To that end, the Company repaired 97.3% of Class 'B' leaks within six months of classification in Fiscal Year 2024. These accelerated repairs reduced the leak hazards as well as methane emissions. Class 'A' leaks are deemed non-hazardous and are monitored for changes in severity.

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

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

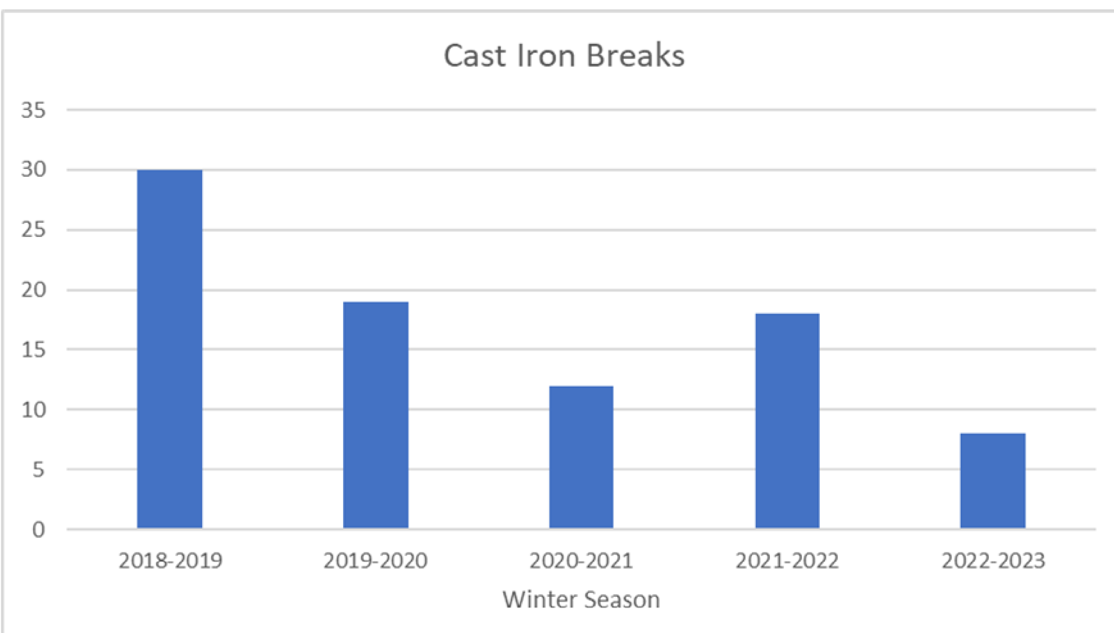
A. UGI Gas has seen a significant reduction in the number of leaks found on its system. This is directly attributable to its prioritization and aggressive replacement of leak-prone mains, services, and other assets. As Table 3 below demonstrates, since 2018, Class 'C' leak repairs have decreased by 29.4%, Class 'B' leak inventories have decreased by 36.5%, and Class 'A' leak inventories have decreased by 43.4%.

Table 3. Leak Inventories & Repairs

	Calendar Year 2018	Calendar Year 2023	Percent Change
C Leak Repairs	1,188	839	29.4% decrease
B Leak Inventory	285	181	36.5% decrease
A Leak Inventory	5,234	2,962	43.4% decrease

Figure 1 below shows the reduction in the number of cast iron breaks each winter season since the 2018-2019 season. There has been an overall 73% reduction in break frequency since the 2018-2019 season. The reduction helps demonstrate effectiveness of cast iron replacement activities.

Figure 1. Cast Iron Main Breaks (2018-2023)



Q. Please discuss UGI Gas's performance in the area of emergency response.

A. UGI Gas performs exceptionally well in the timely response to emergency notifications/calls. For the Fiscal Year ended September 30, 2024, 98.8% of the time, a first responder arrived on the premises within 45 minutes (or less) of receipt of an emergency call. UGI Gas utilizes a combination of shift coverage and on-call schedules to leverage internal field and supervisory resources to provide emergency response coverage 24-hours per day, 365 days per year. I also note that UGI Gas sets performance goals on a 45-minute response, which is more stringent than the benchmark response time as defined by the Commission's Safety Division.[5] Moreover, for Fiscal Year 2024, 99.9% of the time a UGI Gas first responder arrived onsite within one hour of the emergency call. This compares very favorably to the industry average. UGI Gas also had an average emergency dispatch time of only 3.2 minutes for Fiscal Year 2024, which is well below the 15-minute benchmark.

VI. SAFETY INITIATIVES

Q. What programs does UGI Gas have in place regarding employee, customer, and system safety?

A. Safety performance is a core value to UGI Gas. The Company's success depends on its employees' commitment and dedication to safety. Therefore, UGI Gas maintains a culture that drives employees to perform their day-to-day responsibilities with a high degree of

[5] The Commission's Bureau of Audits issued a Management and Operations Audit Report of the Company in October 2019 (at Docket Nos. D-2018-3002234, D-2018-3002235 and D-2018-3002236), which stated:

> The PUC Gas Safety Division defines acceptable emergency dispatch and response times as 15 minutes and 60 minutes, respectively. However, UGI has established a more stringent 45-minute emergency response key performance indicator of 97.8%. (Audit Report, p. 41).

safety. UGI Gas has advanced several initiatives to further develop its safety culture and drive sustainable improvements in safety performance. As an example, in September 2021, UGI Gas implemented a robust telematics and in-cab driver coaching system for all drivers of Company vehicles and continues to enhance and develop its safe driving program through intentional supervisory coaching of "events" triggered by the system, as well as positive recognition of safe defensive driving maneuvers.

UGI Gas is also introducing a focus on High Energy Hazard Assessment and Energy Control in line with the Edison Electric Institute's Safety & Classification Learning Model, an industry-standard approach to categorizing safety learning opportunities to reduce potentially serious or fatal injuries. The UGI Safety team has been trained in use of the model for hazard assessment at crew visits and categorization of incidents or near misses. Employee training in the hazard recognition elements of the model began in October 2024 and will continue through FY2025.

Finally, as discussed previously, UGI Gas incorporates API RP 1173, which establishes a PSMS framework for corporations that operate hazardous liquids and gas pipelines under the U.S. Department of Transportation's jurisdiction. API RP 1173 provides a framework to reveal and manage risk, promotes a learning environment, and continuously improves pipeline safety and integrity. This continuous improvement effort and framework reduces hazards and prevents incidents. UGI Gas completed training in Fiscal Year 2023 and Fiscal Year 2024 of key personnel in root cause analysis to facilitate continuous improvement in both employee safety and pipeline and public safety.

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

A. Other ongoing safety measures and tools include Smith System driver training and a 24-hour Triage Nurse Hotline. The Company has also adopted multiple programs to enhance its safety protocols. One such program is the UGI "Making a Difference by Living Our Values" incentive program, which rewards employees who demonstrate positive safety behaviors, including, but not limited to, leading safety meetings, reporting safety issues, or participating in safety education. UGI has further implemented a "Near Miss/Good Catch" program, which seeks to proactively prevent safety incidents by learning from issues that had the potential for, but did not result in, damage or harm. In addition, the Company uses EcoOnline, a safety incident software, which facilitates incident management and data collection for various types of incidents and tracks those incidents through the investigation process. Moreover, the Company utilizes ISNetworld vendor safety software to qualify contractors and monitor their performance trends. ISNetworld collects safety information from these contractors and compares them against UGI Gas's established safety standards to make sure their safety performance is at a satisfactory level in order to perform work for the Company. ISNetworld conducts ongoing monitoring of the contractor's safety information and alerts UGI Gas if a contractor falls below the Company's minimum safety standards – either in UGI Gas's service territory or anywhere else in the country. This helps ensure that UGI Gas's contractors provide safe and reliable service to the Company's community and customers.

Q. What training initiatives is the Company undertaking?

A. The Company has advanced its offerings at its Learning Center and continues to enhance the training program abilities at the Learning Center. The Learning Center is used for all new hire and employee progression field training. It is also used for ongoing training and operator re-qualification for employees and contractors. Key enhancements in Fiscal Years 2023-2024 were the implementation of robust Emergency Response training exercises utilizing the Leak Town, where trainees respond to real but controlled gas leaks on underground and aboveground, indoor and outdoor leak scenarios under the supervision of instructors.

The Company's operator qualification and technical training team has completed reorganizing, revising, and reformatting the training curriculum to enhance learning through incorporation of additional hands-on practice elements and interaction afforded at the UGI Learning Center. In addition, UGI Gas has nearly completed aligning the evaluation requirements of the Company's operator qualification tasks with the American Society of Mechanical Engineers ("ASME") B31Q Standard and expects to be complete by June of 2025. When that process completes, the Company's evaluation requirements will align with the latest industry best practices.

VII. ENVIRONMENTAL PROGRAMS

A. ENVIRONMENTAL REMEDIATION PROGRAM

Q. Please discuss environmental management at UGI Gas.

A. The environmental group at UGI Gas is focused on three main activities: (1) the investigation and remediation of environmental impacts related to historical operations; (2)

environmental compliance activities, such as permitting and operational improvements; and (3) sustainability and methane reduction activities.

Q. Please describe the Company's investigation and remediation of environmental impacts related to historical operations.

A. From the mid-1800s through the mid-1900s, UGI Gas and its predecessors owned and operated a number of manufactured gas plants ("MGPs") that, prior to the general availability of natural gas, generated gas from other fuel stocks for residential, commercial, and industrial customer use. In Pennsylvania, this process generally used coal as a fuel stock. Some byproducts of this manufacturing process, including coal tars and other residues of the manufactured gas process, are today considered potentially hazardous substances under state and federal environmental laws.

Historically, UGI Gas operated its environmental remediation programs under three consent orders and agreements ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP"). UGI Gas's former utility companies, UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), were each parties to separate COAs with PADEP, and a UGI Gas COA was executed in 2016. Following UGI CPG and UGI PNG's merger into UGI Gas, on October 1, 2020, the three separate UGI COAs were consolidated into a single UGI Gas COA that covers the period through October 1, 2035. This COA obligates the Company to either meet an annual minimum environmental spend commitment of $5.35 million or achieve a minimum annual point total of 9,000 points,[6] with points being issued for the completion of various designated environmental tasks under the COA through October 1, 2035.

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

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

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

A. UGI Gas has held the COA annual minimum spend of $5.35 million as the target projected spend for each year to meet the COA objectives, if minimum annual points cannot be

[6] The COA includes an "accounting system" with provisions to track progress with respect to the investigation, characterization, and remediation of the MGP properties. In any given fiscal year, the Company is required to achieve a minimum of 9,000 points, which demonstrates efforts and progress toward remediation, or exceed the minimum required spend of $5.35 million.

achieved. UGI Gas's average aggregate annual spending over the past three fiscal years is $5.429 million, as shown below in Table 4.

Table 4. Environmental Spent per Fiscal Year

Fiscal Year	Total
2022	$3,244,000
2023	$5,441,000
2024	$7,602,000
Average	$5,429,000

The three-year average amount is used in the calculation of the environmental adjustment shown in UGI Gas Exhibit A, Schedule D-8, as discussed in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement. No. 2).

Forecasted MGP activity costs are anticipated to be higher than the $5.35 million target per the COA and potentially higher than the three-year average of spend of $5.43 million in the next few years, as remediation activities are planned to address areas of impacted soils and groundwater that were identified from prior investigation activities and that are required to move the sites to closure under PADEP Act 2 protocols and COA requirements.

Q. Why does environmental spend vary from the minimum environmental spend set by the COA?

A. While the Company uses the COA minimum spend as a benchmark for environmental cost budgeting, actual costs may exceed the minimum in certain years due to PADEP requirements, varied levels of investigation and remediation activity to address MGP site program priorities, addressing public concerns, changing environmental standards, and site-specific issues such as sensitive habitat and concentration of contaminants. Investigation activities tend to involve lower costs than remediation activities, which have higher costs associated with the active removal or neutralization of impacted soil or groundwater. For example, the 2022 spend shown in Table 5 was lower due to being influenced by a heightened level of investigation activities and lower remediation activity, noting COA requirements were met in that year by completing tasks to achieve the minimum points. However, additional funds beyond the target of $5.35 million were spent in 2023 and 2024, when remediation activities at several sites were conducted.

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

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

B. EMISSIONS REDUCTIONS PROGRAMS

Q. How does UGI Gas quantify the environmental impact of its operations?

A. In addition to the environmental stewardship actions discussed in Mr. Bell's testimony (*e.g.*, oil to gas conversion, energy efficiency and conservation, etc.) (UGI Gas Statement No. 1) that reduce emissions, UGI Gas was a partner in the United States Environmental Protection Agency's ("EPA") voluntary Natural Gas STAR Partnership Program from inception until it was sunset by the agency in 2022. The Natural Gas STAR Partnership provided a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities.

On March 30, 2016, UGI Gas joined with 32 other natural gas utilities to launch the EPA's Natural Gas Methane Challenge Partnership. As a founding member of the Methane Challenge Partnership, UGI Gas has committed to tracking and achieving certain emissions reductions. Participation in this voluntary program includes a commitment to replace infrastructure to achieve a reduction in fugitive methane emissions. UGI Gas reduced fugitive methane emissions associated with pipeline mains and services by 9.8% in 2021-2022 as documented in its most recent program filing. Note that the EPA has also chosen to sunset the Natural Gas Methane Challenge Partnership at the end of 2024 due to updates to the regulatory framework advanced to reduce methane emissions.

In other activity, UGI Gas continues to add Compressed Natural Gas ("CNG") vehicles to its fleet. Currently, over 25% of the fleet is made up of CNG-powered vehicles, with plans to increase the number to approximately 25% by the end of Fiscal Year 2026. Three of the Company's operations locations have CNG filling stations (Archbald, Wilkes-Barre, and Bethlehem), and UGI Gas will install a new station near its Middletown office by the end of the FPFTY. In other locations, utilizing nearby commercial CNG fueling stations makes it feasible to convert fleets to CNG in smaller operations centers. Since 2016, it is estimated that the conversion of gasoline and diesel fueled fleet vehicles to CNG has reduced Company emissions by almost 1,000 metric tons of carbon dioxide equivalent ("$MTCO_2e$").

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT CRB-1

CHRISTOPHER R. BROWN

VICE PRESIDENT – OPERATIONS

UGI Utilities, Inc.

Vice President – Operations	November 2023 - Present
Vice President – Finance and Chief Financial Officer	January 2023 – November 2023
Vice President and General Manager, Rates and Supply (Denver, Pa.)	May 2019 – January 2023
Sr. Director- Operations South Region (Reading, Pa.)	July 2015- May 2019
Manager - Operations (Reading, Pa.)	July 2013 – July 2015
Director- Central Services (Reading, Pa.)	October 2010 – July 2013
Manager – Strategy Processes and Implementation (Reading, Pa.)	February 2010 – October 2010
Manager – Customer Accounting Services (Reading, Pa.)	May 2009 – February 2010
Marketing Manager – East Region (Allentown, Pa.)	April 2008 – May 2009

Amerigas Propane, Inc.

Market Manager (Stroudsburg, Pa.)	June 2005 to April 2008

UGI Utilities, Inc.

Supervisor – Gas Supply and Transportation (Reading, Pa.)	September 2003 – June 2005
Distribution Superintendent (Harrisburg, Pa.)	September 2001 – September 2003
Staff Engineer – Commercial Marketing (Reading, Pa.)	September 1999 – September 2001
New Business Engineer (Allentown, Pa.)	June 1997 – September 1999

Education

MBA, Lebanon Valley College, Annville, Pa.
BS, Civil Engineering, Lehigh University, Bethlehem, Pa.

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-00050539	UGI Utilities Inc. - Annual 1307(f) Filing
Docket No. C-2015-2516051	Centre Park Historic District v. UGI Utilities, Inc.
Docket No. C-2016-2530475	City of Reading v. UGI Utilities, Inc.
Docket No. R-2019-3015162	UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding
Docket No. R-2021-3023618	UGI Utilities, Inc. Electric Division - Base Rate Case Proceeding
Docket No. R-2021-3030218	UGI Utilities, Inc. Gas Division – Base Rate Case Proceeding
Docket No. R-2022-3037368	UGI Utilities, Inc. Electric Division – Base Rate Case Proceeding

UGI GAS STATEMENT NO. 10

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2024-3052716

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:	**Cost of Service**
	Revenue Allocation
	Rate Design

Dated: January 27, 2025

Table of Contents

Glossary of Acronyms

A&G	Administrative and General
ACOSS	Allocated Cost of Service Study
Atrium	Atrium Economics, LLC
CAP	Customer Assistance Program
Commission	Pennsylvania Public Utility Commission
DSIC	Distribution System Improvement Charge
FERC	Federal Energy Regulatory Commission
FPFTY	Fully Projected Future Test Year
LIHEAP	Low-Income Home Energy Assistance Program
LIURP	Low-Income Usage Reduction Program
NARUC	National Association of Regulatory Utility Commissioners
O&M	Operating and Maintenance
Rate DS	Delivery Service
Rate IS	Interruptible Service
Rate LFD	Large Firm Delivery Service
Rate N	General Service – Non-Residential & Non-Residential Transportation
Rate R	General Service – Residential & Residential Transportation
Rate XD Firm	Extended Large Firm Delivery Service
UGI Gas	UGI Utilities, Inc. – Gas Division

I. <u>WITNESS IDENTIFICATION AND BACKGROUND</u>

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

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of UGI Utilities, Inc. – Gas Division's ("UGI Gas" or the "Company").

Q. What is the purpose of your testimony in this proceeding?

A. I prepared and am sponsoring UGI Gas's fully allocated cost of service study ("ACOSS"), which is found in UGI Gas Exhibit D. The ACOSS determines the embedded costs of serving UGI Gas's distribution customers associated with the Pennsylvania Public Utility Commission ("Commission") jurisdiction. I also support the apportionment, or allocation, of the class revenue increase and the Company's rate design proposal.

Q. Please describe your educational background and professional experience.

A. UGI Gas Exhibit JDT-1 contains background information summarizing my education, presentation of expert testimony, and other industry-related activities.

Q. Please summarize the content of your testimony.

My testimony consists of this introduction section (I) and the following five additional sections: (II) Purpose and Principles of Cost Allocation, (III) UGI Gas's Allocated Cost of Service Study, (IV) Principles of Sound Rate Design, (V) UGI Gas's Class Revenues, and (VI) UGI Gas's Rate Design.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Book IX, labeled as UGI Gas Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. I also am sponsoring portions of Book I and Book II, Section 53.53 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation.

II. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. What is the general purpose and use of an ACOSS in regulatory proceedings?

A. The purpose of an ACOSS is to allocate the gas distribution utility's overall fully projected future test year ("FPFTY") costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. An ACOSS represents an analysis of which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop the ACOSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes, or the cost of providing multiple products to the same rate class, use the same facilities and the use by one rate class precludes the use by another rate class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, the ACOSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and commodity developed in the ACOSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Is the preparation of an ACOSS an exact science?

A. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. The allocation of costs using an ACOSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers, with such return on being reflective of a fair rate of return. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. Is there a guiding principle that supports the appropriate allocation of costs?

A. Yes, a fundamental foundational principle, cost causation, should be followed to produce accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs, so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How do you establish the cost and utility service relationships?

A. An important element in the selection and development of a reasonable ACOSS methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. To accomplish this, I reviewed UGI Gas's expense and plant accounts, operational data, usage information, and conducted interviews with UGI Gas employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for the utility's plant and expense elements.

Q. What are the steps to performing an ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the basis to conduct an ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Gas's primary functional cost categories associated with natural gas distribution services include gas supply, transmission, distribution, and customer. Indirect costs that support these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Q. Please describe cost classification.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the gas distribution system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the ACOSS as: (1) customer costs; (2) demand costs; and (3) commodity costs, respectively.

Q. Please describe the types of costs contain in the customer, demand, and commodity costs categories.

A. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to UGI Gas's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by UGI Gas for its customers.

Q. Please describe the cost allocation process.

A. The final step is the allocation of each functionalized and classified cost element to the individual rate class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors. From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service. Notably, UGI Gas has performed direct assignment analysis of its most competitive negotiated rate customers who receive service under Rate XD, and those direct assignment results are reflected in the ACOSS presented in UGI Gas Exhibit D.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors that can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting UGI Gas's ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study is conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. How does the availability of data influence an ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

III. UGI GAS'S ALLOCATED COST OF SERVICE STUDY

Q. Please describe the Atrium Model used in conducting the ACOSS filed in this proceeding.

A. UGI Gas has selected the Atrium excel based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. Atrium developed the Atrium ACOSS Model on a proprietary basis for its consulting engagements and has been used in multiple jurisdictions. This is similar to the Atrium ACOSS Model that UGI Utilities, Inc. – Electric Division presented and that I sponsored in its base rate cases at Dockets No. R-2021-3023618 and No. R-2022-3037368.

Q. Please describe the process of performing UGI Gas's ACOSS presented in this filing.

A. The detailed process description of UGI Gas's ACOSS analysis is presented in Exhibit D, providing a full scope of the process including the development of allocation factors that support various cost of service studies presented in this proceeding as discussed below.

Q. Please discuss the content of Exhibit D?

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(1) and, in particular, Exhibit A - Gas Utilities, by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(1), Exhibit A. The studies contained in UGI Gas Exhibit D are based on costs and operating conditions for the FPFTY ending September 30, 2026.

Exhibit D consists of three sections detailing the process of developing the ACOSS. Section I – Introduction includes an introduction, the general purpose and process of the ACOSS, as well as an overview of the excel-based fully functional ACOSS model presented in this proceeding. Section II – UGI Gas's Cost of Service Procedures presents the ACOSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section II.3) describes all internal and external allocation factors and the allocation processes used in the ACOSS. The last section, Section III – UGI Gas's Cost of Service Results depicts the results of the ACOSS, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the content and schedules included in Exhibit D.

A. Exhibit D contains a narrative description of the ACOSS procedures, provides details on the allocation factors, and contains the following Schedules:

- Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates
- Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 3 - Cost of Service Allocation Study Detail by Account
- Schedule 4 - Account Balances and Allocation Methods
- Schedule 5 - External Allocation Factors
- Schedule 6 - Internal Allocation Factors Summary

Q. What was the source of the cost data analyzed in UGI Gas's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (*i.e.*, total revenue requirement) and schedules contained in this general rate case filing for the FPFTY ending September 30, 2026. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are UGI Gas's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Gas's ACOSS, I included six rate classes:

- Rate R - General Service – Residential & Residential Transportation
- Rate N - General Service – Non-Residential & Non-Residential Transportation
- Rate DS - Delivery Service
- Rate LFD - Large Firm Delivery Service
- Rate XD Firm - Extended Large Firm Delivery Service
- Rate IS - Interruptible Service

Q. How did you classify and allocate the cost of distribution mains?

I classified distribution mains as 100% demand related and allocated their costs in two steps. First, a portion of the costs was directly assigned to Rate XD Firm based on an analysis provided by the Company. Second, I allocated the remaining balance using the Average and Excess ("A&E") method.

Q. Please describe the methodology used for the costs directly assigned to the XD customers.

A. For each customer, a distribution system analysis is performed to determine which assets (including footage, diameter, material type, and vintage year) of the distribution system are utilized to physically serve the customer. Using the Company's plant records, the costs and footage for these assets are summarized based on the footage assigned to the customer as a percentage of the total footage for that asset. A portion of this cost is allocated to that customer based on the customer's throughput on that asset as a percent of the asset total. The calculated costs for all assets assigned to that customer are summed to determine the directly allocated costs for that customer.

Q. Please describe the A&E method.

A. The A&E method allocates costs based on a combination of average usage and peak usage levels. This method is used to allocate costs on both the consistent usage (average demand), and the additional capacity needed during peak times (excess demand). The average demand is determined by the average daily throughput volumes per customer class. The excess demand represents the additional capacity needed to meet the peak demand or maximum usage levels for each customer class. These two factors are weighted based on the system load factor, which is the ratio of average demand to peak demand for the entire system. This factor determines the proportion of costs attributed to average daily usage versus peak capacity requirements.

Q. Can you explain the system load factor and its significance in this method?

A. The system load factor is calculated as follows:

$$\text{Load Factor} = \text{Average Daily Throughput} \div \text{Peak Day Demand}$$

It indicates the efficiency of the system's utilization. A higher load factor suggests that demand is relatively stable, reducing the need for excess capacity. This metric helps balance the cost allocation between average usage and peak demand. UGI Gas's firm service load factor for the FPFTY is 41.27%, which is the system load factor excluding interruptible load. Therefore, the allocation assigns 41.27% of the costs to average daily usage and 58.73% to peak demand.

Q. Why is the interruptible load excluded from the load factor calculations?

A. Interruptible load is excluded from the load factor calculations because it does not contribute to the system's peak day demand, which is a critical driver of infrastructure. In addition, interruptible customers are not assigned any excess load. Interruptible customers agree to reduce or halt their gas usage during periods of high demand, meaning they do not place the same capacity requirements on the distribution system as firm customers. Including interruptible load would misrepresent the true cost drivers and unfairly allocate costs to customers who do not rely on guaranteed peak capacity.

Q. Has the A&E method been approved by the Commission?

A. Yes. The A&E method was approved by the Commission in the last two fully litigated gas rate cases in Pennsylvania. Specifically, the A&E method was upheld in the orders at Docket Nos. R-2020-3018929 and R-2020-3018835, involving rate cases for PECO Energy Company and Columbia Gas of Pennsylvania, respectively.

Q. Did you consider other classification or allocation methods?

A. Yes. I considered the customer/demand classification method and the Peak and Average ("P&A") allocation method. However, the Commission has not traditionally recognized the customer component of gas mains, which makes the customer/demand classification method less viable.[1]

The P&A allocation method has also been evaluated for use in past Pennsylvania rate cases and applies a fixed 50/50 weighting instead of relying on the system load factor.

Q. How do the allocation results differ between the A&E method and the P&A method for UGI Gas in this case?

A. The allocation results for each method are presented below in Table 1. The A&E method allocates a higher percentage of costs to Rate R (46.5% vs. 44.8%) and Rate N (32.0% vs. 29.4%), reflecting its reliance on the system load factor and its balanced approach to cost distribution. On the other hand, the P&A method allocates a higher percentage of costs to Rate LFD (14.7% vs. 11.3%) and Interruptible (4.4% vs. 3.6%), due to its 50/50 weighting of average demand within the peak portion. These differences illustrate how the P&A method allocates more costs to higher-load customers than the A&E method.

[1] *Pa. PUC, et al. v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2020-3018835 (Order entered February 19, 2021), p. 217.

Table 1 – Comparison of Mains Allocators of the Company's ACOSS

	Rate R	Rate N	Rate DS	Rate LFD	Interruptible
A&E	46.5%	32.0%	6.6%	11.3%	3.6%
P&A	44.8%	29.4%	6.7%	14.7%	4.4%

Q. Does UGI Gas's ACOSS include gas commodity costs?

A. Yes. The gas costs reflected in the ACOSS correspond to gas cost revenues that have a neutral impact on the study's results, resulting in a net-zero effect.

Q. Please summarize the results of the Company's ACOSS.

A. Table 2 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 1 of Book IX, UGI Gas Exhibit D. The ACOSS shows an overall revenue requirement of $1,251.3 million and a resulting deficiency of $110.4 million. The revenue deficiency/excess for each rate class shows revenue increases or decreases necessary to get the classes to their cost to serve.

Table 2 - Summary Results of the Company's ACOSS ($000)[2]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
Rate R	$ 723,552	$ 829,647	$ (106,095)	14.7%	5.0%	0.87	0.96
Rate N	248,001	275,116	(27,115)	10.9%	6.4%	0.90	0.99
Rate DS	35,191	34,482	710	-2.0%	9.1%	1.02	1.12
Rate LFD	55,628	51,559	4,069	-7.3%	10.0%	1.08	1.18
Rate XD Firm	39,193	28,840	10,353	-26.4%	15.5%	1.32	1.45
Rate IS	24,486	16,803	7,683	-31.4%	16.1%	1.45	1.59
Total Base	**1,126,051**	**1,236,446**	**(110,395)**	**9.8%**	**6.5%**	**0.91**	**1.00**
Other Revenues	14,836	14,836	-				
Total Company	**1,140,887**	**1,251,282**	**(110,395)**				

The ACOSS shows that Rate R and Rate N classes are being charged rates that recover less than their indicated costs of service, whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. In other words, to set each classes' revenues equal to their cost to serve indicated in the ACOSS, Rate R and Rate N would require an increase in revenues, while all other classes would require a decrease. Additionally, Table 2 provides helpful insights into UGI Gas's class financial metrics, such as the current Rate of Return and corresponding Relative Rate of Return and Current Revenue to Cost Ratio with the corresponding Parity Ratio.

Q. Have you prepared more detailed reports of UGI Gas's ACOSS results?

A. Yes, additional details are included in Exhibit D. Schedule 4 "Account Balances and Allocation Methods" of Exhibit D includes revenue requirement information by FERC account provided by UGI Gas and shows assigned functions, categories, and allocation factors. Schedule 3 "Cost of Service Allocation Study Detail by Account" of Exhibit D

[2] See Exhibit D, Schedule 1, lines 13, 52, 57, 24, 26, and 27.
Percent Change = Class Revenue (Deficiency)/Sufficiency ÷ Current Revenues

presents the resulting allocations by customer class of UGI Gas's proposed revenue requirement based on the results of the computations included in the ACOSS.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles help inform the apportionment of revenues (i.e., revenue targets for each rate class) and the rate design of rate components within each rate class. They include:

1. Cost of Service;
2. Efficiency;
3. Value of Service;
4. Stability/Gradualism;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3] Each of these principles plays an important role in analyzing the rate design proposals of UGI Gas. In addition, these principles are consistent with Pennsylvania practice and precedent,

[3] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

including the *Lloyd* decision,[4] where the Commonwealth Court indicated that cost of service is the “polestar” of ratemaking but that other factors, including those listed above, can be considered as well.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. There are tensions between the cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between the value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and

[4] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

V. UGI GAS'S CLASS REVENUES

Q. Please describe the approach generally followed in allocating UGI Gas's proposed revenue increase of $110.4 million to its various rate classes.

A. To reflect the results of the class cost-of-service study, the Company is proposing to move all rate classes closer to the overall system rate of return and, as a result, reduce the current subsidies occurring between classes. This movement of classes towards the overall system rate of return is consistent with regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement of that case.

Q. Please describe the proposed approach to apportion UGI Gas's proposed revenue increase to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The benchmark option evaluated under UGI Gas's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. This is shown above in Table 2 where the changes in each classes revenues would be set to their deficiency or surplus. It was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue, given the large increase required to move some classes to parity. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time while addressing issues of gradualism. The decision was made to provide rate decreases to competitively negotiated classes XD and IS equivalent to incorporating the present Distribution System Improvement Charge ("DSIC") rider into base rates. These decrease amounts have then been effectively constrained within the Company's "contract customer" group (DS, LFD, XD, IS) by increases being allocated to classes DS and LFD. Rate R and Rate N would receive increases to move them closer to parity, equivalent to 1.25 the system increase. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the reduction in the subsidies occurring between classes. With these considerations, the Company is proposing the revenue changes shown in the table below.

Table 3 – Proposed Class Revenue Apportionment
Base Distribution Margin ($000)[5]

Customer Classes	Current Revenues	Proposed Revenues	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return	Proposed Revenue to Cost Ratio
Rate R	$ 723,552	$ 806,648	$ (83,096)	11.5%	7.1%	0.97
Rate N	248,001	$ 275,342	(27,341)	11.0%	7.9%	1.00
Rate DS	35,191	$ 36,291	(1,100)	3.1%	8.9%	1.05
Rate LFD	55,628	$ 56,729	(1,101)	2.0%	9.5%	1.10
Rate XD Firm	39,193	$ 38,083	1,110	-2.8%	13.6%	1.29
Rate IS	24,486	23,353	1,133	-4.6%	13.9%	1.39
Total Base	**$ 1,126,051**	**$ 1,236,446**	**$ (110,395)**	**9.8%**	**7.9%**	**1.00**

[5] See Exhibit D, Schedule 1, lines 10, 52, 58, 61, 70, and 72.

Q. To what degree does the Company's proposed revenue apportionment move the classes toward their cost of service?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes and moves classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable such that class revenues and rates are closer to the indicated cost of service for each rate class.

Table 4 below compares the current and proposed rate of returns and parity ratios. The Company's proposal moves the return for all rate classes closer to the Company's proposed return. Likewise, parity ratios move closer to the desired 1.0 level.

Table 4- Comparison of Relative Rate of Return by Rate Class
Base Distribution Margin ($000)[6]

Customer Classes	Current Revenues	Proposed Revenues	Current Return	Proposed Return	Current Parity Ratio	Proposed Parity Ratio
Rate R	$ 723,552	$ 806,648	5.0%	7.1%	0.96	0.97
Rate N	$ 248,001	$ 275,342	6.4%	7.9%	0.99	1.00
Rate DS	$ 35,191	$ 36,291	9.1%	8.9%	1.12	1.05
Rate LFD	$ 55,628	$ 56,729	10.0%	9.5%	1.18	1.10
Rate XD Firm	$ 39,193	$ 38,083	15.5%	13.6%	1.45	1.29
Rate IS	$ 24,486	$ 23,353	16.1%	13.9%	1.59	1.39
Total Base	**$ 1,126,051**	**$ 1,236,446**	**6.5%**	**7.9%**	**1.00**	**1.00**

Q. To what degree does the Company's proposed revenue apportionment decrease the existing subsidies between rate classes?

A. Table 5 below summarizes the current and proposed subsidies and the reduction in all customer classes' subsidies resulting from the Company's proposed revenue apportionment.

[6] Exhibit D, Schedule 1, lines 10, 52, 24, 70, 27, and 73.

Table 5 - Comparison of Present and Proposed Subsidies ($000)[7]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Rate R	$ (33,713)	$ (22,999)	$ 10,714
Rate N	(832)	226	1,058
Rate DS	4,491	1,810	2,682
Rate LFD	9,693	5,170	4,523
Rate XD Firm	11,791	9,243	2,548
Rate IS	8,569	6,550	2,019
Total Company	$ -	$ -	$ -

VI. UGI GAS'S RATE DESIGN

Q. Please summarize the rate design changes UGI Gas has proposed in this rate proceeding.

A. In general, UGI Gas's rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide natural gas distribution service to those customers. UGI Gas has proposed the following rate design changes to its current tariff schedules:

- Rate R – Increase in the Monthly Customer Charge from $15.00 to $19.95, with the remaining proposed increase to be recovered in the Volumetric Charge.
- Rate N – Increase in the Monthly Customer Charge from $27.38 to $36.42, with the remaining proposed increase to be recovered in the Volumetric Charge.
- Rate DS – Increase in the Monthly Customer Charge from $260 to $300, with the remaining proposed increase to be recovered in the Volumetric Charge, with no difference between the former South & Central District and the former North District.

[7] See Exhibit D, Schedule 1, lines 35 and 63. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

- Rate LFD – Increase in the Demand Charge from $5.9965 per Mcf to $7.6956 per Mcf.
- Rate XD Firm – Decrease equivalent to the DSIC rider amount.
- Rate IS – Decrease equivalent to the DSIC rider amount.

Q. What is the impact on customers in the former North District under Rate DS from applying the same rates as those in the former South and Central Districts?

A. The overall impact on customers in the former North District under Rate DS, as a result of applying the same rates as those in the former South and Central Districts, is an increase of 17.9%. This increase is approximately 1.24 times the system-wide average increase of 14.4%. This increase reflects the adjustment necessary to align the former North District rates with the existing structure in the former South and Central Districts, ensuring consistency across the system.

Q. Has the Company prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?

A. Yes. UGI Gas Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A. Epler, presents a detailed comparison of present and proposed revenues for each of UGI Gas's rate classes.

Q. How does the ACOSS support the proposed increases to customer charges?

A. Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. Table 6 below provides the information related to the current and proposed customer charges for Rates R, N, and DS, compared to the customer related unit cost – per customer, per month.

Table 6 - Customer Charge Current, Proposed, and ACOSS Unit Cost Results ($)[8]

Customer Classes	Current Basic Facilities Charge	Proposed Basic Facilities Charge	Customer Related Unit Cost	Demand and Customer Related Unit Cost
Rate R	15.00	19.95	51.19	76.07
Rate N	27.38	36.42	68.13	221.76
Rate DS	260.00	300.00	537.96	2,174.94

As seen in the above table, the proposed increases in customer charges are still under the customer related unit cost identified in the ACOSS. These include the customer portion of distribution facilities and customer service and billing costs.

Q. Can you please discuss the results in Table 6 above within the context of the Company's proposed customer charges and past Commission precedent?

A. Yes, past Commission precedent defines customer-related costs for inclusion in a customer charge as costs associated with meters and services and related O&M expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The Company is proposing a Rate R customer charge of $19.95, which is below the $51.19 within Table 6

[8] See Exhibit D, Schedule 2, lines 118 and 119.

above, and represents meter reading, customer service, and billing and collection expenses. These are all costs historically allowed by the Commission in a customer charge. Taking into consideration past precedent in Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company is proposing to move the Rate R customer charge to $19.95. Similarly, the Company is proposing customer charge increases to Rate N and Rate DS that are still below the customer related unit cost for these rates.

Q. Why are setting customer charges more in alignment with the fixed cost of service an important outcome of ratemaking?

A. These proposed customer charges help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood, convey more appropriate price signals with respect to recovery of fixed utility costs, benefit low-income customers that have higher than average use, and are not regressive in application to low-income customers who may have little control over their use of energy and are negatively impacted when recovering more costs in volumetric charges.

Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric block prices, which has the effect of causing some customers to pay too much while others pay too little. The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether natural gas is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure the Company's recovery of a greater portion of its fixed costs of providing service. Inasmuch as costs are not related to usage, they should be recovered, to the extent possible, through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers easily recognize fixed cost charges and are used to these pricing structures in their everyday lives. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is cold, and conversely should not pay less when the weather is warm.

Q. Please expand on why an increase in the Rate R customer charge would benefit low-income customers.

A. There is a common misconception that low-income customers are low-usage customers. This is not a correct characterization of low-income customers who are indeed higher-use customers. As recorded in the Company's Universal Service Program effective December 1, 2024, the average use for a customer in the Customer Assistance Program ("CAP") is

113.6 Mcf/year.[9] This is almost 30% higher than the average of other Company's residential customers use of 88.4 Mcf/year.

Also, all else equal, higher customer charges necessitate lower variable charges. The collection of costs through fixed or volumetric charges is only the means of collecting the revenue to cover costs for a specific customer class. The amount of total revenue does not change. Higher usage customers pay more when more fixed customer costs are embedded in the volumetric rates. This creates a social equity concern, as customers who can afford to reduce their usage through energy efficiency investments can decrease their bills by making such investments, while those customers who cannot afford to make energy efficiency investments will see increases in their bills. Examples of those who could possibly afford to reduce their usage include higher-income households who can undertake more expensive energy efficiency measures or through a living situation such as a single individual versus a family with infant children.

Further, recovering fixed costs in volumetric charges places regressive burdens on low-income households who have to make decisions to reduce their gas usage that impacts their quality of life. While some environmental advocates may prefer that households stop using natural gas altogether, families still use gas for basic human needs such as keeping themselves warm and to cook and care for themselves.

[9] UGI Gas, Docket No. R- 2024-3048828; Purchased Gas Cost Compliance Filing Including Quarterly Adjustment; Supplement No. 54 to Tariff UGI Gas - Pa. P.U.C. No. 7 and Pa. P.U.C. No. 7S; Effective December 1, 2024, Supporting Documentation Schedule B.

Lastly, considerations relating to the intersection of income and rate design would be amiss if they did not include discussions relating to UGI Gas's low-income programs. UGI Gas offers a continuum of low-income targeted programs, beyond CAP, including Low-Income Home Energy Assistance Program ("LIHEAP"), Low-Income Usage Reduction Program ("LIURP"), and weatherization assistance. There is no reason to send the wrong price signal to all customers when the impacts on low-income customers are mixed (i.e., their ability to respond to higher variable charges, the lower quality of living they may choose to respond to higher variable charges, and the fact that low-income customers that use higher than average will disproportionately be impacted by higher variable charges) and when there are robust programs in place that target bill and weatherization assistance for low-income customers.

Q. Have you conducted an analysis of the difference between the current \$15.00 monthly residential customer charge and the proposed \$19.95 a month charge on low-income customers?

A. Yes. Table 7 compares the amount a low-income customer with an average usage of 113.6 Mcf/year would pay between the customer charge and the volumetric charge under the Company's proposal (Scenario A) of increasing the monthly customer charge to \$19.95, and Scenario B, which keeps the monthly customer charge unchanged at \$15.00.

Table 7 – Comparison of Annual Charges for Average CAP Customer[10]

Average CAP Customer	Scenario A	Scenario B	B - A	% change
Customer Charges	$ 239.40	$ 180.00	$ (59.40)	-33.0%
Distribution Charges	727.93	807.04	$ 79.11	9.8%
Total Annual Charges	**$ 967.33**	**$ 987.04**	$ 19.71	2.0%

The comparison shows that while the Company's proposal increases the annual customer charges by $59.40 or 33%, the increase is more than offset by the $79.11 or 9.8% lower distribution charges. In other words, by not changing the current customer charge, customers ultimately face higher overall costs because of the substantial increase in distribution charges. This suggests that any policy or pricing adjustment leading to keeping the customer charge unchanged would shift more costs to the distribution component, increasing the financial burden on low-income customers, as much as 2%, over the year. As previously stated, a volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the utility's system; and (4) needlessly inflate bills in the winter months. The important policy point in this discussion is that it makes no economic sense to send the wrong economic price signals to all customers in order to supposedly benefit a small

[10] Scenario A uses a monthly customer charge of $19.95 and distribution charges of $6.4078/Mcf, as proposed by the Company. Scenario B uses the current monthly customer charge of $15.00 and distribution charges of $7.1042/Mcf, which would be necessary to recover Rate R's proposed revenue.

subset of low-income customers. It is far more efficient to address the issues of low-income customers directly through programs and assistance, such as the Company's CAP.

VII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Gas's ACOSS, class revenues, and rate design.

[redacted] My conclusions and recommendations are as follows:

- The Commission should accept the results of the Company's ACOSS as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system.
- The Commission should accept the results from the Company's ACOSS as a guide to evaluate and set UGI Gas's class revenues and rate design in this proceeding.
- The Commission should accept the Company's proposed apportionment of revenues to its rate classes because it reasonably balances the various criteria that the Company considered in the revenue apportionment process and moves classes towards their cost to serve.
- The Commission should approve the rate design proposed by the Company because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6)

recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JDT-1

John D. Taylor

MANAGING PARTNER

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

- California Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.

- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the development of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

TRANSACTION EXPERIENCE

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

FINANCIAL ANALYSIS AND MARKET RESEARCH

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost-of-service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.