Pennsylvania Public Utility Commission,	Docket No.:
v.	R-2025-3059523
UGI Utilities, Inc. - Gas Division	
In-Person Evidentiary Hearing	

Pages 561 - 689

Hearing Room #5, Plaza Level
Commonwealth Keystone Building
400 North Street
Harrisburg, PA

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Docket No. R-2025-3059523

Hearing Date: June 3, 2026

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James Garren

I&E Statement No. 1
Witness: Zachari Walker
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES INC. – GAS DIVISION

Docket No. R-2025-3059523

Direct Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission or PUC) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT BACKGROUND?

A. My education and employment background is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of the ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) and to recommend adjustments to the Company's proposed operating and maintenance (O&M) expenses, taxes, and rate base for the fully projected future test year (FPFTY) ending September 30, 2027.[1]

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. WHAT ARE THE TEST YEARS USED BY THE COMPANY IN THIS PROCEEDING?

A. UGI Gas uses the twelve months ended September 30, 2025, as the historic test year (HTY), the twelve months ending September 30, 2026, as the future test year (FTY), and the twelve months ending September 30, 2027, as the FPFTY.[2]

Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTED REVENUE INCREASE.

A. The Company's base rate case was filed on January 28, 2026, with a total requested increase of $99,368,000 to the claimed total present rate operating revenues of $1,234,682,000 resulting in an overall revenue requirement of $1,334,050,000.[3]

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1 UGI Gas Book I, Statement of Reasons, p. 5.
2 UGI Gas Book I, Statement of Reasons, p. 5.
3 UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-1, Line 5.

UGI Gas states the additional revenues represent an 8.05% increase to present rate revenues;[4] however, that 8.05% proposed change in rates includes commodity revenues in the calculation. The actual requested increase to the Company's claimed present rate distribution revenues is 12.86% ($99,368,000 ÷ $772,828,000).[5] As commodity costs can represent a substantial share of a customer's bill that can change quarterly through purchased gas cost proceedings, including these revenues in calculating the magnitude of the requested revenue increase artificially minimizes the actual impact of the distribution revenue increase requested.

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

[4] UGI Gas Book I, Statement of Reasons, p. 1.
[5] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-1, Line 4 ÷ Line 1.

	UGI Gas FPFTY Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Rate Case Expense	$1,760,000	$880,000	($880,000)
Payroll Expense	$82,522,000	$81,369,000	($1,153,000)
Employee Benefits	$12,417,000	$11,653,000	($764,000)
Advertising Expense	$2,061,000	$1,415,000	($646,000)
Employee Activity Costs	$583,000	$388,000	($195,000)
Membership Dues and Subscriptions	$1,593,000	$1,210,000	($383,000)
EE&C Plan Costs	$12,026,000	$10,833,000	($1,193,000)
[BEGIN PROPRIETARY]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]
			[END PROPRIETARY]
Taxes:			
Payroll Taxes	$6,271,000	$6,183,000	($88,000)
Total Tax Adjustments			**($88,000)**
Rate Base:			
Cash Working Capital	$66,523,000	$65,691,000	($832,000)
[BEGIN PROPRIETARY]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]
			[END PROPRIETARY]

SUMMARY OF I&E'S OVERALL POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for UGI Gas is $1,288,531,000. This recommended revenue requirement represents an increase of $53,385,000 to

I&E's adjusted present rate revenues of $1,235,146,000. This total recommended allowance incorporates my adjustments made in this direct testimony to O&M expenses, taxes, and rate bate, and those made in the testimony of I&E witnesses Drew Breuning [6] and Ethan Cline.[7]

A calculation of the I&E recommended revenue requirement is shown in the table below:

[BEGIN PROPRIETARY]

[END PROPRIETARY]

[6] I&E Statement No. 2.
[7] I&E Statement No. 3.

PUC ANNUAL REPORT FORMAT

Q. HOW DOES UGI GAS PRESENT ITS DATA IN ITS PUC ANNUAL REPORT FILINGS?

A. In response to I&E-RE-1, the Company stated that the PUC's Gas Annual Report of UGI Utilities, Inc. for the year ended December 31, 2024 does not solely reflect gas operations, citing Schedules 200 (Comparative Balance Sheet Assets and Other Debits and Comparative Balance Sheet Liabilities and Other Credits),[8] 213 (Accounts Receivable from Associated Companies and Accounts Payable from Associated Companies),[9] and 216 (Unamortized Debt Discount and Expense and Unamortized Premium on Debt)[10] that include data for the legal entity, UGI Utilities, Inc.[11]

Q. WHAT IS THE COMPANY'S BASIS FOR PRESENTING UGI UTILITIES, INC. DATA, WHICH ENCOMPASSES AMOUNTS FOR BOTH GAS AND ELECTRIC OPERATIONS?[12]

A. The Company explained that the dollar amounts for the referenced schedules cannot be meaningfully split between gas and electric operations and that any change to the

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8 *Gas Annual Report of UGI Utilities, Inc. for the Year Ended December 21, 2024*, p. 15, (Posted May 5, 2025), https://www.puc.pa.gIov/pcdocs/1877483.pdf, accessed April 5, 2026.

9 *Gas Annual Report of UGI Utilities, Inc. for the Year Ended December 21, 2024*, p. 22, (Posted May 5, 2025), https://www.puc.pa.gov/pcdocs/1877483.pdf, accessed April 5, 2026.

10 *Gas Annual Report of UGI Utilities, Inc. for the Year Ended December 21, 2024*, p. 24, (Posted May 5, 2025), https://www.puc.pa.gov/pcdocs/1877483.pdf, accessed April 5, 2026.

11 I&E Exhibit No. 1, Schedule 1.

12 *Gas Annual Report of UGI Utilities, Inc. for the Year Ended December 21, 2024*, pp. 15, 22, and 24, (Posted May 5, 2025), https://www.puc.pa.gov/pcdocs/1877483.pdf, accessed April 5, 2026.

way they present the numbers would require a formal explanation or petition and that there is no justification for this change.[13]

Q. DO YOU AGREE THAT THE COMPANY CANNOT SPLIT DOLLAR AMOUNTS FOR THE REFERENCED SCHEDULES BETWEEN UGI GAS AND ITS PARENT COMPANY'S ELECTRIC OPERATIONS (UGI ELECTRIC)?

A. No. In UGI Electric's Federal Energy Regulatory Commission (FERC) Form 1 dated December 31, 2023, pages 200-201, in the section entitled "Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion"[14] the Company was able to break down utility plant and related items between gas and electric operations, thus indicating the availability of such breakdown for utility plant accounts, depreciation, and amortization. It stands to reason that other balance sheet accounts would be broken down at a subaccount level between UGI Gas and UGI Electric. However, if not, UGI Gas should still be required to provide a breakdown of the plant-related items that it already breaks down for FERC.

[13] I&E Exhibit No. 1, Schedule 1.
[14] I&E Exhibit No. 1, Schedule 2, pp. 2-3.

Q. DO YOU AGREE THAT MODIFYING THE REPORT TO ONLY INCLUDE DATA FOR GAS OR ELECTRIC OPERATIONS WOULD REQUIRE THE COMPANY TO FILE A PETITION WITH THE COMMISSION?

A. I am advised by counsel that UGI Gas would not need to file a petition. To the extent necessary, this will be addressed in the I&E briefs.

Q. WHAT WOULD BE THE BENEFIT OF REQUIRING THE COMPANY TO PRESENT SEPARATE DATA IN THE GAS AND ELECTRIC ANNUAL REPORTS?

A. As currently presented, the reports are misleading. Requiring separate data for all schedules in the gas and electric annual reports filed with the Commission would provide a more useful tool for the parties to use for comparative analysis in base rate cases and other proceedings.

Further, if the Company cannot meaningfully split the schedules cited above into gas and electric operations, it calls into question the validity of information filed in separate UGI Gas or UGI Electric rate cases.

Q. WHAT DO YOU RECOMMEND REGARDING PUC ANNUAL REPORT FILINGS GOING FORWARD?

A. I recommend that the Company be required to display all schedules included in the annual filings, including Schedules 200, 213, and 216, separately based on its gas or electric operations.

RATE CASE EXPENSE

Q. BRIEFLY DESCRIBE THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a regulated utility's allowable claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, fees to outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes.[15]

[15] "A Guide to Utility Ratemaking," by James H. Cawley and Norman J. Kennard (2018 Edition), p. 112, https://www.puc.pa.gov/General/publications_reports/pdf/Ratemaking_Guide2018.pdf, accessed April 2, 2026.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by calculating the average number of months between the filing dates of a utility's recently filed base rate cases.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. UGI Gas's FPFTY rate case expense claim is $1,760,000.[16]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. UGI Gas' $1,760,000 rate case expense claim is the sum of proposed expenses for external consultants of $917,000, external legal expenses of $750,000, and miscellaneous costs of $93,000.[17]

Additionally, in response to I&E-RE-19, Part D, the Company stated its normalization period is based on the anticipated one-year interval between the instant proceeding and the Company's next base rate filing. The anticipated one-year normalization period is based on a number of factors as follows: (1) assessments of future capital requirements and system improvements including the Company's Long-Term Infrastructure Improvement Plan, (2) pressure to file a rate case within one year due to increasing operating expenses, (3) revenue requirements for plant additions being ineligible for distribution system improvement charge

[16] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-10.
[17] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-10.

treatment, and (4) capital cost rates and higher risks associated with a rate of return reflect and support the Company's financial and risk profile.[18]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend a normalized annual allowance of $880,000 for rate case expense, or a reduction of $880,000 ($1,760,000 - $880,000) for the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on adjusting the normalization period to match the historic average base rate case filing frequency of 24 months as detailed below.

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE NORMALIZATION PERIOD.

A. The Company's historic filing frequency does not support a one-year recovery period for rate case expense. The Company's three most recent base rate case filing dates and corresponding details for the current filing are as follows:

[18] I&E Exhibit No. 1, Schedule 3, p. 1.

Docket No.	Date Filed[19]	Filing Interval
R-2025-3059523	January 28, 2026	12 months
R-2024-3052716	January 27, 2025	36 months
R-2021-3030218	January 28, 2022	24 months
R-2019-3015162	January 28, 2020	

Including the current rate case, filed on January 28, 2026, the average historic filing frequency is 24 months [(12 months + 36 months + 24 months) ÷ 3]. Therefore, I recommend the 24-month average historic filing frequency be used as the normalization period. This is consistent with the Commission's emphasis on the importance of considering the utility's history of rate case filings when determining the normalization period of rate case expenses. Normalizing the total claim over the average historic filing frequency of 24 months yields my recommended FPFTY allowance of $880,000 [($1,760,000 ÷ 24 months) x 12 months] for rate case expense. My recommended FPFTY allowance represents a reduction of $880,000 ($1,760,000 - $880,000) to the Company's FPFTY claimed rate case expense.

Q. HAVE OTHER UTILITIES BEEN GRANTED A NORMALIZATION PERIOD BASED ON SPECULATION OF FUTURE RATE CASE FILINGS?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation (PPL Electric) permission to normalize its rate case expense over a 24-month period

[19] I&E Exhibit No. 1, Schedule 2, p. 2.

based on the expected timing of future base rate case filings.[20] That base rate case was filed on March 30, 2012; however, PPL Electric did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing. I&E's recommended normalization period in the 2012 proceeding was a 32-month interval based on PPL Electric's historic filing frequency.[21] I&E's recommendation in that instance produced a much more accurate result than PPL Electric's stated future intention to file a rate case.

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. The following seven cases resulted in the Commission using each utility's historic average filing frequency.

First, in a base rate case filed by Emporium Water Company, the Commission adopted I&E's recommended historic filing frequency finding in favor of I&E's recommended five-year normalization based on historic average filing frequency that was rounded down from 64 months.[22]

Second, in a 2016 base rate case filed by the City of DuBois the Commission agreed with I&E's recommendation to use an historic filing frequency finding in

[20] *Pa. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, pp. 47-48 (Order Entered December 28, 2012).
[21] I&E Statement No. 2, pp. 13-14 at Docket No. R-2012-2290597.
[22] *Pa. PUC v. Emporium Water Company*, Docket No. R-2014-2402324, p. 50 (Order Entered January 28, 2015).

favor of I&E's recommended 64-month normalization which matched the actual historic filing frequency.[23]

Third, in Columbia Gas of Pennsylvania, Inc.'s (Columbia Gas) 2020 base rate case filing, the Commission held that the normalization period should align with the frequency of historic filings rather than Columbia's stated intent to file its subsequent rate case.[24]

Fourth, in PECO Energy Company – Gas Division's (PECO Gas) 2020 base rate filing, the Commission granted I&E's recommended five-year normalization period rather than PECO Gas' claim based on a three-year period because the Commission determined a normalization period based on actual historic filing frequency is more reliable than future speculation.[25]

Fifth, in a base rate case filed by Philadelphia Gas Works' (PGW) in 2023, the Commission agreed with I&E's recommended 53-month normalization period rather than PGW's claim based on a three-year period because the Commission granted a normalization period based on actual historic filing frequency and not based on PGW's future intention to file a rate case.[26]

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[23] *Pa. PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

[24] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

[25] *Pa. PUC v. PECO Energy Company (Gas Division)*, Docket No. R-2020-3018929, Opinion and Order, p. 119 (Order Entered June 22, 2021).

[26] *Pa. PUC v. Philadelphia Gas Works*, Docket No. R-2023-3037933, Opinion and Order, pp. 65-66 (Order Entered November 9, 2023).

Sixth, in the 2023 Columbia Water Company base rate proceeding, the Commission held that the normalization period should align with the historic filing frequency rather than that company's intent to file its next rate case, and that the intent to file a base rate case does not justify deviating from the Commission's practice of relying on historic filing frequency.[27]

Finally, in the recent 2025 Columbia Gas base rate proceeding, the Commission agreed with the Administrative Law Judge (ALJ) and the Office of Consumer Advocate (OCA) that "fourteen months is a more appropriate and reasonable length of time for normalization, as it more closely aligns with Columbia's actual history and frequency of rate case filings."[28]

Q. GIVEN THESE COMMISSION ORDERS AND THE COMPANY'S FILING HISTORY, IS THE CLAIMED 12-MONTH RECOVERY PERIOD REASONABLE?

A. No. As explained above, the Company's demonstrated historic filing frequency is 24 months, therefore, normalizing the total claim over this average historic filing frequency is more appropriate.

[27] *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, Opinion and Order, p. 34 (Order Entered January 18, 2024).

[28] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, Opinion and Order, p. 138 (Order Entered December 9, 2025).

PAYROLL EXPENSE

Q. WHAT IS INCLUDED IN PAYROLL EXPENSE?

A. The Company's payroll expense claim includes operations and maintenance salaries and wages for union, exempt, and non-exempt employees.

Q. WHAT IS UGI GAS' CLAIM FOR PAYROLL EXPENSE?

A. The Company's claim for payroll expense is $82,522,000.[29]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. UGI Gas based its claim on the budgeted HTY headcount, adjusted to reflect an additional 23 positions in the FTY. The FPFTY headcount was projected to stay level with the adjusted FTY headcount.[30] The payroll claim also reflects the Company's anticipated vacancy rate[31] and an annualization adjustment, calculated based on a projected 4.0% wage increase for union employees occurring in the FPFTY.[32]

Q. DO YOU AGREE WITH THE COMPANY'S PAYROLL EXPENSE CLAIM?

A. No.

[29] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-7, p. 1.
[30] UGI Gas Book II, SDR-RR-20.
[31] UGI Gas Book II, SDR-RR-21 and I&E Exhibit No. 1, Schedule 3, p. 1.
[32] UGI Gas Statement No. 2, p. 11 and UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-7, pp. 1-2.

Q. WHAT IS YOUR RECOMMENDATION FOR PAYROLL EXPENSE?

A. I recommend an allowance of $81,369,000 for payroll expense, or a reduction of $1,153,000 ($82,522,000 - $81,369,000) to UGI Gas' claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation reflects the application of a vacancy adjustment as it is unreasonable to assume the Company will maintain 100% full staffing based on its own historical vacancy records. Since there will always be search and placement gaps involved in filling vacancies, there will always be a certain level of vacancies on a day-to-day operating basis that should be reflected in UGI Gas' payroll expense allowance. The adjustment for average historical vacancy levels is required to reflect a more accurate employee complement in the FPFTY. My recommendation is a more accurate representation of the payroll expense level at the end of the FPFTY.

Q. HOW DID YOU DETERMINE YOUR PAYROLL EXPENSE ADJUSTMENT?

A. I applied a calculated historical three-year average vacancy rate to the Company's claim for payroll expense.

Q. DID THE COMPANY INCLUDE A VACANCY ADJUSTMENT IN ITS FPFTY PAYROLL EXPENSE CLAIM?

A. Yes. UGI Gas states that it incorporated a 4.7% vacancy rate adjustment in its FPFTY salaries and wages expense prior to the inclusion of overtime wages, other wages, and an annualization adjustment. The 4.7% vacancy rate applied to the Company's projected unadjusted salaries and wages expense of $79,484,000 resulted in a vacancy adjustment of $3,736,000.[33]

Q. DO YOU AGREE WITH UGI GAS' VACANCY ADJUSTMENT RATE?

A. No. Based on my analysis of the Company's historical vacancy levels, UGI Gas did not incorporate enough vacancies when developing its payroll expense claim.

Q. WHAT VACANCY RATE DO YOU RECOMMEND?

A. I recommend a vacancy rate of 6.15%.

Q. PLEASE EXPLAIN HOW YOU CALCULATED YOUR PAYROLL EXPENSE VACANCY ADJUSTMENT.

A. I reviewed UGI Gas' response to I&E-RE-24, which requested the number of employees and vacancies for fiscal year (FY) 2023, FY 2024, the HTY, the FTY, and the FPFTY.[34] Based on the information provided in that response and its

[33] I&E Exhibit No. 1, Schedule 4, pp. 1-2.
[34] I&E Exhibit No. 1, Schedule 5.

corresponding Attachment I&E-RE-24(c),[35] I calculated an average monthly vacancy rate for FY 2023 of 5.68%, FY 2024 of 7.96%, and the HTY of 4.80%, or a three-year historical average of 6.15% [(5.68% + 7.96% + 4.80%) ÷ 3].[36]

Next, in response to I&E-RE-25, UGI Gas provided a breakdown of its FPFTY payroll expense claim.[37] In place of the Company's 4.7% vacancy adjustment, I applied my recommended three-year historical average vacancy rate of 6.15% to the Company's unadjusted projected FPFTY salaries and wages expense of $79,484,000, resulting in a vacancy adjustment of $4,888,000 ($79,484,000 x .0615), or an adjusted payroll expense recommendation, prior to inclusion of overtime wages, other wages, and the annualization adjustment, of $74,596,000 ($79,484,000 - $4,888,000).

To arrive at my total recommended allowance for payroll expense, I added the Company's claimed overtime and other wages of $5,830,000 and annualization adjustment of $943,000[38] to my recommended adjusted salaries and wages expense of $74,596,000. My recommended total allowance for payroll expense is $81,369,000 ($5,830,000 + $943,000 + $74,596,000), a reduction of $1,153,000 ($82,522,000 - $81,369,000) to the Company's FPFTY claim.

[35] I&E Exhibit No. 1, Schedule 5, pp. 3-7.
[36] I&E Exhibit No. 1, Schedule 6.
[37] I&E Exhibit No. 1, Schedule 4, p. 2.
[38] It should be noted that my payroll adjustment would affect the annualization adjustment; however, the impact is de minimis, so I did not adjust that item.

PAYROLL TAXES

Q. WHAT IS INCLUDED IN PAYROLL TAXES?

A. Payroll taxes represent taxes imposed on employers and employees that are usually calculated as a percentage of the salaries paid to staff. Payroll taxes generally fall into two categories: (1) deductions from employees' wages; and (2) taxes paid by the employer based on the employees' wages. UGI Gas has made a claim in this filing for its employer share of those payroll taxes.

Q. WHAT IS THE COMPANY'S CLAIM FOR PAYROLL TAXES?

A. UGI Gas' claim for payroll tax expense is $6,271,000.[39]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. UGI Gas' payroll tax claim consists of social security, federal unemployment tax (FUTA), and state unemployment tax (SUTA).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR PAYROLL TAXES?

A. I recommend an allowance of $6,183,000 for payroll taxes, or a reduction of

[39] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-31, Column 5, Lines 4-6.

$88,000 ($6,271,000 - $6,183,000) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommended adjustment to payroll taxes is based on my recommended reduction of payroll expense based on my vacancy adjustment and the percentage of total payroll tax to total payroll. The calculation of my recommendation is as follows:

Company FPFTY Payroll Tax Claim	$6,271,000
Company FPFTY Payroll Expense Claim	÷ $82,522,000
% Payroll Taxes to Payroll Expense Claim	7.60%
I&E Recommended Payroll Expense Adjustment	x $1,153,000
I&E Recommended Payroll Tax Adjustment	$88,000

EMPLOYEE BENEFITS (NET OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS)

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR EMPLOYEE BENEFITS EXPENSE (NET OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS)?

A. The employee benefits expense (net of pension and other post-employment benefits) claim includes medical insurance, benefits allocated from UGI Corporation, 401k

plan contributions, life and disability insurance, professional development, and other benefits.[40]

Q. WHAT IS THE COMPANY'S CLAIM FOR EMPLOYEE BENEFITS (NET OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS)?

A. The Company is claiming employee benefits (net of pension and other post-employment benefits) of $12,417,000 ($15,367,000 - $1,531,000 – 1,419,000).[41]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company based its FPFTY claim for employee benefits (net of pension and other post-employment benefits) on its budgeted 2027 fiscal year amount.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR EMPLOYEE BENEFITS EXPENSE?

A. I recommend an allowance of $11,653,000, or a reduction of $764,000 ($12,417,000 – 11,653,000) to the Company's FPFTY claim.

[40] I&E Exhibit No. 1, Schedule 7, p. 3.
[41] I&E Exhibit No. 1, Schedule 7, p. 3.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommended adjustment is made in line with my recommended vacancy adjustment in the payroll expense section above. I applied the 6.15% vacancy rate to the Company's claim for employee benefits (net of pension and other post-employment benefits) to calculate my employee benefits expense adjustment. The result is my recommended adjustment of $764,000 ($12,417,000 x 0.0615), or a recommended allowance of $11,653,000 ($12,417,000 - $764,000).

ADVERTISING EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR ADVERTISING EXPENSE?

A. The Company's advertising expense claim is $2,061,000.[42]

Q. WHAT IS THE BASIS FOR THE COMPANY'S ADVERTISING EXPENSE CLAIM?

A. UGI Gas' advertising expense claim is a combination of public health and safety programs of $1,091,000; conservation of energy programs of $273,000; explanations of bill practices of $318,000; and other advertising programs of $380,000, published in multiple formats.[43]

Additionally, in response to I&E-RE-43, the Company provided a breakdown of the advertising expenses by program and corresponding associated costs in

[42] UGI Gas Book I, Section 53.53, Attachment III-A-25.
[43] UGI Gas Book I, Section 53.53, Attachment III-A-25.

Attachment I&E-RE-43.[44] Additionally, in response to I&E-RE-44, UGI Gas provided Attachment I&E-RE-44 detailing the advertising publications included in the advertising expense claim.[45]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDED ALLOWANCE FOR ADVERTISING EXPENSE?

A. I recommend an allowance of $1,415,000, or a reduction of $646,000 ($2,061,000 - $1,415,000) to the Company's advertising expense claim.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDATION?

A. My recommended allowance is the sum of (1) the historical two-year average advertising expense for the Public Health & Safety programs of $957,000 [($1,026,000 + $887,000) ÷ 2], Conservation of Energy programs of $156,000 [($76,000 + $235,000) ÷ 2], Explanation of Bill Practices $173,000 [($178,000 + $167,000) ÷ 2], and Other Advertising Programs – Stakeholder Newsletters $129,000 [($127,000 + $131,000) ÷ 2], and (2) removal of the entire claim for Other Advertising - Community Event Sponsorships of $191,000, as sourced from

[44] I&E Exhibit No. 1, Schedule 8, p. 4.
[45] I&E Exhibit No. 1, Schedule 9.

Attachment I&E-RE-43.[46] The calculation of my recommended adjustment is as follows:

Advertising Program	Company Claim	I&E Recommended Allowance	I&E Recommended Adjustment
Public Health & Safety	$1,091,000	$957,000	($134,000)
Conservation of Energy	$273,000	$156,000	($117,000)
Explanation of Bill Practices	$318,000	$173,000	($145,000)
Other Advertising Programs			
- Stakeholder Newsletters	$189,000	$129,000	($60,000)
- Community Event Sponsorships	$191,000	$0	($191,000)
Total[47]	$2,061,000	$1,415,000	($646,000)

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the two-year historical average expense levels of the Public Health & Safety, Conservation of Energy, Explanation of Bill Practices, and Other Advertising Programs – Stakeholder Newsletters. The two-year historical averages represent more appropriate levels of expense compared to the Company's proposed substantial increases between the HTY actual expense levels and the FPFTY advertising expense claims, the calculation for each program is shown below:

[46] I&E Exhibit No. 1, Schedule 8, p. 4.
[47] Difference in totals due to rounding.

Advertising Program	HTY Expense[48]	FPFTY Claim[49]	Company Proposed Increase[50]	Company Proposed % Increase[51]
Public Health & Safety	$887,000	$1,091,000	$204,000	23.00%
Conservation of Energy	$235,000	$273,000	$38,000	16.17%
Explanation of Bill Practices	$167,000	$318,000	$151,000	90.42%
Other Advertising Programs				
- Stakeholder Newsletters	$131,000	$189,000	$58,000	44.27%
Total[52] [53]	$1,420,000	$1,871,000	($451,000)	31.76%

I excluded the annual advertising expenses for FY 2023 due to the those expenses levels varying significantly from the FY 2024, HTY, FTY projections, and the FPFTY claim.[54]

Regarding my recommendation to disallow the Other Advertising Programs – Community Event Sponsorships of $191,000, this is based on this form of advertising being inappropriate to include for ratemaking purposes. The Other Advertising Programs – Community Event Sponsorships program is represented by advertisements for events such as the Parade of Homes, the Fulton Theatre, and the Reading Royals minor professional ice hockey team.[55] These types of advertisements and sponsorships represent goodwill, or promotional, advertising

48 I&E Exhibit No. 1, Schedule 8, p. 4.
49 I&E Exhibit No. 1, Schedule 8, p. 4.
50 FPFTY Advertising Claim – HTY Expense.
51 [{(FPFTY Advertising Claim – HTY Expense) ÷ HTY Expense} x 100].
52 Difference in totals due to rounding.
53 Totals do not include expense amounts for Other Advertising Programs – Community Events Sponsorships which is addressed below.
54 I&E Exhibit No. 1, Schedule 8, p. 4.
55 I&E Exhibit No. 1, Schedule 9, pp. 3-7.

and do not provide direct benefits to ratepayers. Additionally, it is not apparent that these advertisement programs meet any of the six criteria enumerated in 66 Pa. C.S.A. §1316(a) (Section 1316(a)) regarding the recovery of advertising expenses allowable for ratemaking purposes. Section 1316(a) states, "The Commission shall also disallow as operating expense for ratemaking purposes expenditures for other advertising, unless and only to the extent that the Commission finds that such advertising is reasonable and meets one or more of the following criteria: (1) Is required by law or regulation, (2) Is in support of the issuance, marketing, or acquisition of securities or other forms of financing, (3) Encourages energy independence by promoting the wise development and use of domestic sources of coal, oil, or natural gas and does not promote one method of generating electricity as preferable to other methods of generating electricity, (4) Provides important information to the public regarding safety, rate changes, means of reducing usage or bills, load management or energy conservation, (5) Provides a direct benefit to ratepayers, (6) Is for the promotion of community service or economic development.[56] This topic will be addressed more fully by the I&E prosecutors in briefs.

Since the Other Advertising Programs – Community Event Sponsorships expenses do not meet the criteria of Section 1316(a), these expenses are

[56] 66 Pa. C.S.A. § 1316(a)(1) through (6).

inappropriate to include for ratemaking purposes, and therefore should be disallowed.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR ADVERTISING EXPENSE.

A. My recommended advertising expense allowance is $1,415,000 – the sum of recommended allowances for the following programs: (1) Public Health & Safety of $957,000; (2) Conservation of Energy of $156,000; (3) Explanation of Bill Practices of $173,000; and (4) Other Advertising Programs – Stakeholder Newsletters of $129,000, based on the two-year historical average expense. Additionally, I recommended the removal of the Other Advertising Programs – Community Event Sponsorships of $191,000, based on these advertising expenses not satisfying the criteria of Section 1316(a) and, therefore, not appropriate to include for ratemaking purposes.

My recommended allowance of $1,415,000 ($2,061,000 - $646,000) for advertising expense represents a reduction of $646,000[57] ($134,000 + $117,000 + $145,000 + $60,000 + $191,000) to the Company's advertising expense claim.

[57] The total recommended reduction variance is due to rounding.

EMPLOYEE ACTIVITY COSTS

Q. WHAT IS THE COMPANY'S CLAIM FOR EMPLOYEE ACTIVITY COSTS?

A. UGI Gas is claiming $583,000 for employee activity costs in the FPFTY.[58]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company stated the employee activity costs are incurred to boost morale, promote team building, foster a positive work environment, and recognize employees for their contributions to the service provided by UGI Gas to its customers and communities. The employee activity costs claim includes $195,000 for a Company picnic, $233,000 for safety and service awards, and $155,000 for other activities such as department meetings and field employee welfare.[59]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of $388,000 ($583,000 - $195,000) or a reduction of $195,000 to the Company's employee activity costs claim.

[58] I&E Exhibit No. 1, Schedule 10, p. 3.
[59] I&E Exhibit No. 1, Schedule 10, p. 3.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I recommend disallowing the costs for the Company picnic of $195,000 for ratemaking purposes. Company picnics do not directly support the provision of safe and reliable gas service, and therefore should not be funded by ratepayers.

MEMBERSHIP DUES AND SUBSCRIPTIONS

Q. WHAT IS THE COMPANY'S CLAIM FOR MEMBERSHIP DUES AND SUBSCRIPTIONS?

A. UGI Gas' claim for membership dues and subscriptions is $1,593,000.[60]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on costs incurred for membership dues, excluding the lobbying portion of dues.[61] Additionally, in response to I&E-RE-13, Part F, UGI Gas provided Attachment I&E-RE-13.2 containing detailed explanations for why each organization is included in its membership dues claim.[62]

Q. DO YOU AGREE WITH THE COMPANY'S MEMBERSHIP DUES AND SUBSCRIPTIONS CLAIM?

A. No.

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60 UGI Gas Book II, Attachment SDR-RR-30.
61 UGI Gas Book II, SDR-RR-30, Part C and Attachment SDR-RR-30.
62 I&E Exhibit No. 1, Schedule 11, pp. 4-6.

Q. WHAT IS YOUR RECOMMENDATION FOR MEMBERSHIP DUES AND SUBSCRIPTIONS?

A. I recommend an allowance of $1,210,000, or a reduction of $383,000 ($1,593,000 – $1,210,000) to the Company's membership dues and subscriptions claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on adjusting the amount included for ratemaking purposes for the Gas Technology Institute (GTI) and removing the dues paid to numerous organizations that are not appropriate to include for ratemaking purposes.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION FOR THE GAS TECHNOLOGY INSTITUTE.

A. In response to I&E-RE-13, Part B, the Company provided Attachment I&E-RE-13.1 that shows the historically incurred costs beginning in FY 2023 and membership dues amounts claimed for GTI. The amount paid to GTI has increased significantly between 2023 and the HTY, from $25,000 to $345,000 respectively.[63] Without more of an explanation than the increase being due to retaining membership, as stated in response to I&E-RE-13, Part C,[64] the amount claimed of $371,000 for GTI dues is unreasonable.

[63] I&E Exhibit No. 1, Schedule 11, p. 3.
[64] I&E Exhibit No. 1, Schedule 11, p. 1.

UGI Gas states the membership to GTI provides funds and access to research and development on pipeline integrity, leak detection, system efficiency, and infrastructure modernization technologies and facilitates adoption of new technologies that improve reliability, reduce outages, and lower operating costs.[65] Since the purpose of this membership is supported, but the amount of dues paid is not, I recommend the acceptable allowance for GTI membership dues be equal to the three-year historical average dues of $125,000 [($25,000 + $6,000 + $345,000) ÷ 3]. This represents a reduction of $ 246,000 ($371,000 - $125,000) to the Company's GTI membership dues claim.

Q. HOW DID YOU DETERMINE THE REMAINING ADJUSTMENT TO THE COMPANY'S MEMBERSHIP DUES CLAIM?

A. The remainder of my adjustment reflects my recommended disallowance of various chambers of commerce and economic development agencies based on the fact that these costs are not necessary for the provision of safe and reliable natural gas service. The entities recommended for disallowance are listed in the table below:

[65] I&E Exhibit No. 1, Schedule 11, p. 4.

Organization	Amount
Economic Development of Lancaster	$32,500
Pennsylvania Chamber of Business and Industry	$30,733
Lehigh Valley Economic Development Corporation	$20,000
Greater Reading Economic Partnership	$15,000
Lebanon Valley Economic Development Corporation	$7,500
Wyoming Valley Chamber of Commerce	$7,000
Bethlehem Economic Development Corporation	$5,000
Scranton Chamber of Commerce	$3,750
Wyoming County Chamber of Commerce	$2,500
Greater Susquehanna Chamber of Commerce	$2,500
Harrisburg Regional Chamber of Commerce	$2,000
Wayne Economic Development Company	$1,750
Focus Central Pennsylvania – North	$1,500
Home Builders Association of Metropolitan Harrisburg	$1,498
Lancaster Chamber of Commerce	$1,250
The Greater Carbondale Chamber of Commerce	$750
Shippensburg Area Chamber of Commerce	$541
Williamsport/Lycoming Chamber of Commerce	$500
Develop Tioga	$500
Carlisle Chamber Membership	$284
Total	**$137,000**

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO REMOVE THE MEMBERSHIP DUES FOR THE ORGANIZATIONS IN THE TABLE ABOVE?

A. Membership dues paid to chambers of commerce and economic development agencies are not necessary for the provision of safe and reliable natural gas service and, therefore, should be disallowed for ratemaking purposes.

Q. IS YOUR RECOMMENDATION AN ATTEMPT TO DICTATE WHETHER THE COMPANY CONTINUES TO PAY FOR MEMBERSHIP TO THESE ORGANIZATIONS?

A. No. I am merely asserting that ratepayers should not be required to fund the identified memberships.

Q. ARE THERE ANY RECENT COMMISSION ORDERS THAT SUPPORT YOUR RECOMMENDATION?

A. Yes. In the 2025 Columbia Gas base rate case, the Commission denied that utility's request to recover chamber of commerce fees in base rates, adopting the Administrative Law Judge's recommendation "that the Company not be permitted to recover chamber of commerce membership costs."[66]

INCENTIVE COMPENSATION

Q. WHAT IS INCENTIVE COMPENSATION?

A. Incentive compensation consists of payments made to eligible employees that are in addition to the employees' base salaries and wages. An incentive compensation payout is generally based on the achievement of key performance indicators or triggers (customer service, safety, and financial goals) established by the Company or affiliated/parent company.

[66] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, p. 158 (Order Entered December 9, 2025).

Q. WHAT IS UGI GAS' CLAIM FOR INCENTIVE COMPENSATION?

A. The Company's claim for incentive compensation is a total of $10,884,000.[67] Additionally, in the confidential response to I&E-RE-32, **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** that is included in its rate base claim.

Q. WHAT IS BASIS FOR THE COMPANY'S INCENTIVE COMPENSATION CLAIM?

A. The Company's claim is based on costs for UGI Utilities' Management Incentive Plan, UGI Utilities Executive Annual Bonus Plan, UGI Corporate Executive Annual Bonus Plan, and UGI Corporate Non-Executive Annual Bonus Plan. Plan specific information was provided in the Company's confidential attachments SDR-RR-27.1 through SDR-RR-27.7.[69] Additionally, in UGI Gas' confidential response to I&E-RE-32, UGI Gas provided confidential attachments I&E-RE-32.1, I&E-RE-32.7, and I&E-RE-32.8, and highly confidential attachments I&E-RE-32.2 through I&E-RE-32.6[70] that describe plan details and identify specific dollar amounts attributed to some of the plans included in the Company's incentive compensation claim.

[67] UGI Gas Book II, SDR-RR-27.
[68] I&E Exhibit No. 1, Schedule 12, pp. 24-25.
[69] UGI Gas Book II, SDR-RR-27.
[70] I&E Exhibit No. 1, Schedule 12, pp. 4-29.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** or a reduction of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Company's expense claim. Additionally, I recommend an allowance of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** or a reduction of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Company's rate base claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

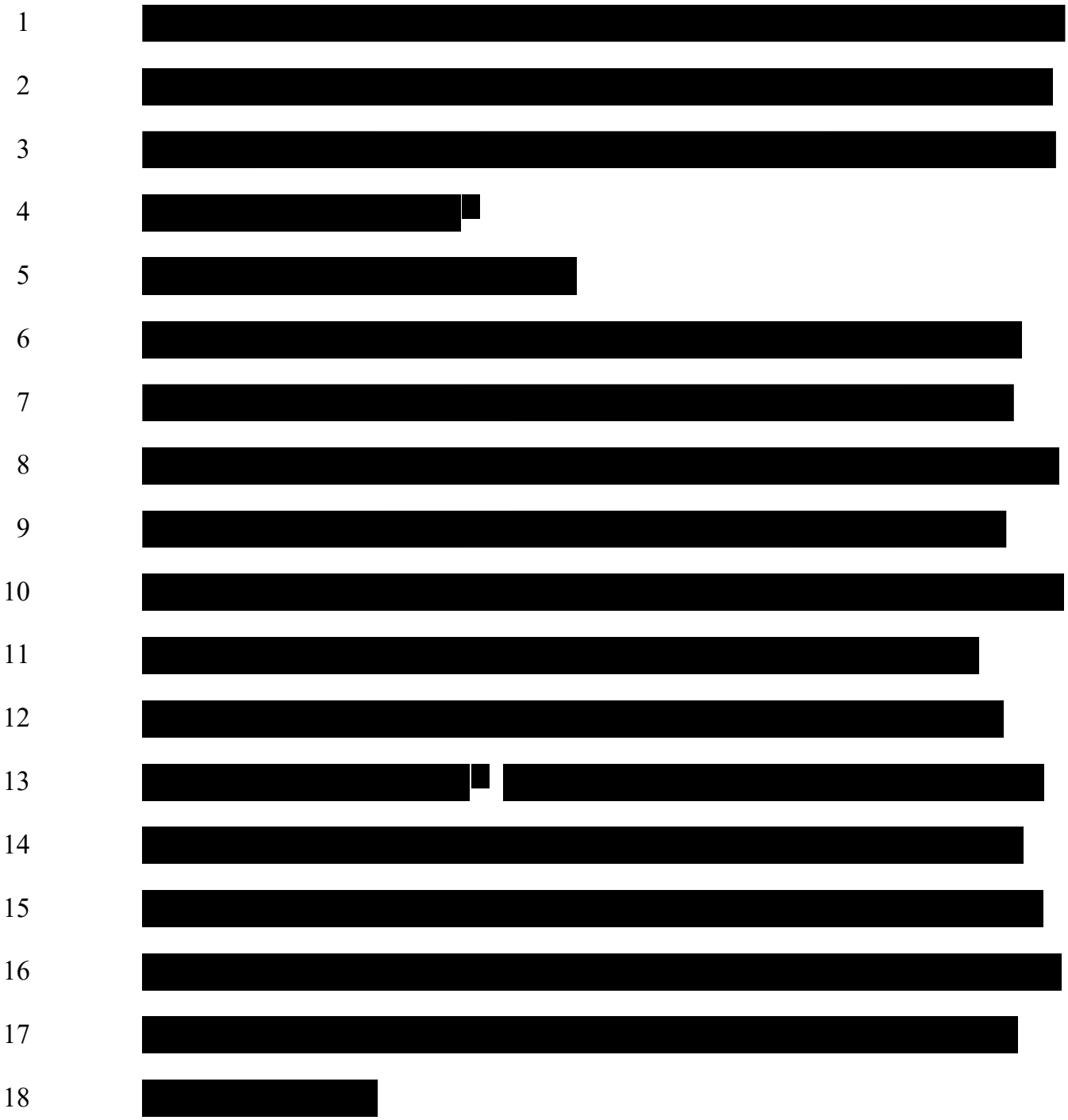
A. Following my review of the Company's confidential attachments to SDR-RR-27 and in response to I&E-RE-32, I have determined the items below are inappropriate to include for ratemaking purposes.

First, it should be noted that it is not completely apparent what is included in the entirety of the Company's incentive compensation expense claim. In attachments I&E-RE-32.7[71] and I&E-RE-32.8[72] the Company identifies the following expense amounts below: **[BEGIN PROPRIETARY]**

[71] I&E Exhibit No. 1, Schedule 12, pp. 24-25.
[72] I&E Exhibit No. 1, Schedule 12, pp. 26-29.

[redacted]

[73] I&E Exhibit No. 1, Schedule 12, pp. 24-25.
[74] Attachment SDR-RR-27.1 and Attachment SDR-RR-27.2.



[75] I&E Exhibit No. 1, Schedule 12, pp. 24-25.
[76] Attachment SDR-RR-27.4, p. 12 and Attachment SDR-RR-27.5, p. 14.
[77] Attachment SDR-RR-27.6, p. 1.
[78] I&E Exhibit No. 1, Schedule 12, pp. 24-25.
[79] I&E Exhibit No. 1, Schedule 12, pp. 24-25.
[80] I&E Exhibit No. 1, Schedule 12, p. 10.

[redacted]

[81] I&E Exhibit No. 1, Schedule 12, pp. 26-29.
[82] I&E Exhibit No. 1, Schedule 12, pp. 26-29.
[83] I&E Exhibit No. 1, Schedule 12, pp. 16-19.

[redacted]

[redacted]

[END PROPRIETARY] Executive bonuses are not necessary for the safe and reliable provision of natural gas service and are therefore inappropriate to include for ratemaking purposes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR INCENTIVE COMPENSATION.

A. My recommendation for incentive compensation is summarized as follows:

[BEGIN PROPRIETARY]

[redacted]

[84] I&E Exhibit No. 1, Schedule 12, pp. 24-25.

[redacted]

[END PROPRIETARY]

Q. HAS THE COMMISSION RECENTLY ADJUSTED A COMPANY'S CLAIM FOR INCENTIVE COMPENSATION BASED ON THE REMOVAL OF INCENTIVE COMPENSATION BASED ON FINANCIAL GOALS?

A. Yes. In the most recent Columbia Gas base rate proceeding, the Commission removed 70% of Columbia Gas' total incentive compensation claim, equal to the portion based on financial goals, finding that it was not necessary in providing safe and reliable service to ratepayers. The Commission stated:

> We shall deny Columbia's Exception Nos. 3 and 4. We agree with the ALJs' recommendation to adopt the OCA's proposed downward adjustment of $1,798,165, to the Company's cash-based STI compensation expense claim of $2,568,807. As noted by the ALJs and the OCA, Columbia did not explain why 70% of the incentive compensation expense is necessary to provide adequate service to ratepayers, give that only 30% of this claimed expense is related to operational safety and customer experience. *See* OCA St. 2 at 18-19. Accordingly, we shall adopt the ALJs' recommendation to apply a downward adjustment of $1,798,165, [$2,568,807 x 70% = $1,798,165], to reflect a total allowance for cash-based STI compensation expense of $770,642. [$2,568,807 - $1,798,165 = $770,642].
>
> We also agree with the ALJs and the OCA that Columbia failed to present credible evidence that the totality of its LTI

> compensation plan is reasonable, give that only 30% of the plan is related to safety, customer care, customer satisfaction, or other benefits to ratepayers. Accordingly, we shall adopt the ALJs' recommendation that only 30% of the Company's LTI compensation expense claim of $754,446, or $226,334, [$754,446 x 30% + $226,334], be allowed for ratemaking purposes, resulting in a downward adjustment of $528,112. [$754,446 - $528,112 = $226,344].[85]

ENERGY EFFICIENCY AND CONSERVATION PLAN EXPENSE

Q. WHAT IS THE COMPANY'S ENERGY EFFICIENCY AND CONSERVATION PLAN?

A. UGI Gas' Energy Efficiency and Conservation (EE&C) Plan is made up of six natural gas programs, including one program focused on combined heat and power, designed to decrease natural gas consumption and annual customer energy costs. The Company's EE&C Plan is a continuation of the most recent iteration pursuant to the settlement approved by the Commission in its 2019 base rate case at Docket No. R-2018-3006814.[86] The Company's budgeted EE&C Plan expenses of $12,366,000[87] are recovered through gas distribution base rates, reconciled to match the amount of the current EE&C Rider charge at the time of the Company's filing.[88]

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85 *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499 (Order Entered December 9, 2025). *See generally* Disposition of Incentive Compensation, p. 123.

86 I&E Exhibit No. 1, Schedule 13, p. 3.

87 UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-19.

88 UGI Gas Book III, Statement No. 2, p. 15.

Q. WHAT IS THE COMPANY'S EE&C PLAN EXPENSE CLAIM?

A. UGI Gas' EE&C Plan expense claim is $12,026,000.[89]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDED ALLOWANCE FOR EE&C PLAN EXPENSE?

A. I recommend an FPFTY allowance of $10,833,000 be included for ratemaking purposes. This represents a reduction of $1,193,000 ($12,026,000 - $10,833,000) to the Company's claim.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDED ALLOWANCE?

A. In response to I&E-RE-35, Part B, UGI Gas provided Attachment I&E-RE-35-B that shows the budget variance percentage, the percentage of actual costs under- or overspent compare to the budgeted costs, for each program included in the EE&C Plan for FY 2021, FY 2022, FY 2023, and FY 2024.[90] I then used the data provided in UGI Gas' EE&C Plan Report for Phase 1 Year 6[91] to recreate the same data table for FY 2025.[92]

[89] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-19.
[90] I&E Exhibit No. 1, Schedule 14.
[91] I&E Exhibit No. 1, Schedule 13, pp. 4-11.
[92] I&E Exhibit No. 1, Schedule 15.

Next, I calculated the total cost variance percentage, the percentage of actual costs spent compared to the budgeted costs, for each fiscal year by adding one to each fiscal year total budget variance percentage. Finally, I took the average of the three most recent historical fiscal year cost variance percentages. The table below show the calculation:

		FY 2023	FY 2024	FY 2025
1	Total Budget Variance	-3.1%	-8.9%	-25.3%
2		+ 1.00	+ 1.00	+ 1.00
3	Total Cost Variance	96.9%	91.1%	74.7%
4	Average Cost Variance (Sum of Line 3 ÷ 3)	87.6%		

Finally, I applied the calculated three-year historical average cost variance percentage to the unadjusted budgeted EE&C Plan expenses of $12,366,000, the result being my recommended EE&C Plan expense allowance of $10,833,000 ($12,366,000 x 0.876).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation sets a more accurate expense level to include for ratemaking purposes for the EE&C Plan expenses for the following reasons. First, the Company has underspent its EE&C budget every year since FY 2021, as the historical data shows.[93] Next, in response to I&E-RE-35, Part D, UGI Gas provided Attachment I&E-RE-35-C listing the program savings variance by fiscal year for FY

[93] I&E Exhibit No. 1, Schedule 15.

2020 through the HTY.[94] The budgeted EE&C program savings have been met once in that timespan. Lastly, the Company's most recent EE&C Plan total cost variance percentage of 74.7% was the EE&C Plan's worst performance since the program's first year when the Company only spent 82.1% of the total EE&C Plan budget.

Given the historical inability to spend the budgeted EE&C Plan costs and the historical inability to achieve the budgeted EE&C program savings, it is unreasonable to include the level of expense the Company is claiming in the FPFTY. My recommended allowance uses the three-year historical average cost variance to set an appropriate EE&C Plan expense level and balances the benefits of a properly funded EE&C Plan with a reasonable expense level to include for ratemaking purposes.

CASH WORKING CAPITAL

Q. WHAT IS CASH WORKING CAPITAL (CWC) ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC includes the amount of funds necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses, and the utility's receipt of revenue in payment of services rendered.

[94] I&E Exhibit No. 1, Schedule 14, p. 4.

Q. HOW DOES THE COMPANY CALCULATE ITS CWC CLAIM?

A. UGI Gas calculates its CWC by using a lead/lag study. A lead/lag study measures the difference in time between: (1) the time services are rendered until payment of those services is received, and (2) the time between the point when a utility has incurred an expense and the actual payment of the expense. Stated differently, the lead/lag study measures how many days exist on average between the midpoint of the service period and the date the payment is made.

Q. WHAT IS THE COMPANY'S CWC CLAIM?

A. The Company's claim for CWC is $66,523,000.[95]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. UGI Gas' claim is based on the HTY lead/lag study, applying total revenues and total expenses for the FPFTY ending September 30, 2027.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend a total allowance of $65,691,000, or a reduction of $832,000

[95] UGI Gas Book V, Exhibit A – Fully Projected, Schedule C-4, p. 1, Line 5.

($66,523,000 - $65,691,000) to the Company's claim.[96]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on my adjustments to O&M expenses as discussed above.

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to UGI Gas' claims for revenues, expenses, taxes, and rate base must be consistently brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, which is known as iteration, effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

Q. WHAT O&M ADJUSTMENTS DID YOU INCORPORATE WHEN DETERMINING A RECOMMENDED CWC ALLOWANCE?

A. All O&M adjustments that are cash-based expense claims should be included when determining the Company's CWC requirement. Therefore, I have included cash-

[96] I&E Exhibit No. 1, Schedule 16, p. 2, Line 14.

based O&M recommendations when computing the overall recommended CWC allowance.

Q. SUMMARIZE WHERE EACH OF THE RECOMMENDED O&M EXPENSE ADJUSTMENTS ARE REFLECTED IN THE CWC COMPUTATIONS.

A. Payroll - Expense Lag Days:

I recommended a reduction to payroll expense of $1,153,000 which is reflected as a reduction to the Payroll Expense Lag Days calculation.[97]

Other Expenses – Expense Lag Days:

The following recommended adjustments are reflected in the Other Expenses - Expense Lag Days calculation:[98] rate case expense adjustment of $880,000, employee pension and benefits (net of pension and other post-employment benefits) adjustment of $764,000, advertising expense adjustment of $646,000, employee activity cost adjustment of $195,000, membership dues and subscriptions adjustment of $383,000, EE&C Plan expense adjustment of $1,193,000, and incentive compensation expense adjustment of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** as discussed above, producing a total decrease of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Other Expenses Lag Days calculation.

[97] I&E Exhibit No. 1, Schedule 16, p. 2, Line 3.
[98] I&E Exhibit No. 1, Schedule 16, p. 2, Line 5.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. However, I reserve the right to update my position as affected by any information received after the preparation of this direct testimony.

Zachari Walker

Professional and Educational Background

Experience:

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
March 2021 to Present:
Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement

Bridgestone Retail Operations LLC, Nashville, Tennessee
December 2014 to July 2020:
Business Manager
Conducted in-depth operations analysis to determine key performance indicators, corresponding trends, and opportunities for business growth. Promoted business efforts through public teambuilding events, customer recognition and celebrations, and offsite visits with community leaders and vendor partners. Designed development plans with up to 11 team members implementing scheduled periodic reassessment and goal tracking.

Education/Professional Development:

Bridging the Gap, Holly Ridge, North Carolina, 2021
Business Analyst Blueprint Training Program, 36 PD hours

Stevenson University, Stevenson, Maryland, 2014
Bachelor of Science, *magna cum laude*, Business Administration
Concentration in Finance

Professional Affiliations:

International Institute of Business Analysis (IIBA), Pickering, Ontario, Canada

Utility-Related Trainings & Other Courses/Webinars:

NARUC Fundamentals of Utility Law, September 9 – November 25, 2025

Pennsylvania Public Utility Commission Rate School 2022, January 18-February 8, 2022

Michigan State University Institute of Public Utilities Accounting and Ratemaking Course 2021, September 14-16, 2021

NARUC Staff Subcommittee on Accounting & Finance, Spring 2021 Virtual Conference, April 6-8, 2021

Testimony Submitted:

R-2025-3057164	PPL Electric Utilities, Inc.
R-2025-3054394	Citizens' Electric Company of Lewisburg, PA
R-2025-3054392	Wellsboro Electric Company
A-2025-3052983	Pennsylvania-American Water Company – Acquisition of the Wastewater Treatment Plant and Collection System of Elizabeth Borough Municipal Authority - §1329
R-2024-3052357	Pike County Light & Power Company - Gas
R-2024-3047824	Aqua Pennsylvania Wastewater, Inc.
R-2024-3047822	Aqua Pennsylvania, Inc.
R-2024-3046523	Duquesne Light Company
R-2024-3045966	Philadelphia Gas Works – §1307(f)
R-2023-3042805	Community Utilities of Pennsylvania, Inc. – Wastewater Division
R-2023-3042804	Community Utilities of Pennsylvania, Inc. – Water Division
R-2023-3037933	Philadelphia Gas Works
R-2023-3035730	National Fuel Gas Distribution Corporation
R-2022-3032369	Citizens' Electric - Lewisburg

Testimony Submitted (cont.):

R-2022-3032806	The York Water Company – Wastewater Division
R-2022-3031340	The York Water Company – Water Division
R-2021-3030218	UGI Utilities, Inc. – Gas Division
R-2021-3026682	City of Lancaster – Bureau of Water
R-2021-3026116	Borough of Hanover – Hanover Municipal Water Works
R-2021-3025207	Community Utilities of Pennsylvania Inc. – Wastewater Division
R-2021-3025206	Community Utilities of Pennsylvania Inc. – Water Division

Casework Not Requiring Testimony:

R-2026-3060186	Philadelphia Gas Works – §1307(f)
R-2025-3053241	Philadelphia Gas Works – §1307(f)
R-2023-3041575	Conneaut Lake Park Water Corporation, Inc.
R-2023-3040285	PECO Energy Co. – Gas Operations §1037(f)
R-2022-3032250	PECO Energy Co. – Gas Operations §1307(f)

I&E Exhibit No. 1
Witness: Zachari Walker
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES INC. – GAS DIVISION

Docket No. R-2025-3059523

Exhibit to Accompany

The

Direct Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

I&E-RE-1

Request:

Reference UGI Utilities, Inc. – Gas Division's (UGI Gas or Company) Gas Annual Report filed with the Pennsylvania Public Utility Commission (PUC or Commission) for the year ended December 31, 2024. Provide the following:

A. State whether all pages solely reflect gas related operations data.

B. If the response to Part A above is negative, provide a detailed explanation for why it is appropriate to produce a Gas Annual Report that includes dollar amounts from non-gas related operations.

C. If the response to Part A above is negative, identify any Commission authorization to include non-gas related operations data in the schedules of the Gas Annual Report.

D. Provide a corrected report as necessary to reflect only UGI Gas in all schedules and state whether the Company agrees to continue filing annual reports going forward that reflect only UGI Gas information as UGI Electric should have its own separate reports.

Response:

A. The Pennsylvania Public Utility Commission's (PUC) Gas Annual Report of UGI Utilities Inc. for the year ended December 31, 2024 reflects gas operations except for the following schedules:

- "200. Comparative Balance Sheet Assets and Other Debits" and "200. Comparative Balance Sheet Liabilities and Other Credits"
- "213. Accounts Receivable from Associated Companies (Account 146) and Accounts Payable to Associated Companies (Account 234)"
- "216. Unamortized Debt Discount and Expense and Unamortized Premium on Debt (Accounts 181, 225)"

B. The aforementioned pages reflect the financial position of the legal entity, UGI Utilities, Inc. and cannot be meaningfully split between gas and electric. Certain

I&E-RE-1 (Continued)

assets and liabilities, such as long-term debt, common equity, deferred taxes, and shared corporate assets, are not inherently gas or electric in nature.

C. This filing methodology has been historically accepted by the PUC and the format has been maintained for year-over-year consistency.

D. Changing a previously accepted methodology would require formal explanation or petition and there is no justification for this modification.

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

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

The e report are mandatory under the Federal Power Act, Section 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
UGI Utilities, Inc.	End of: 2023/ Q4

Name of Respondent: UGI Utilities, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	5,076,091,139	268,527,577	4,535,744,681				271,818,881
4	Property Under Capital Leases	2,760,493		2,760,493				
5	Plant Purchased or Sold							
6	Completed Construction not Classified	432,937,148	45,191,369	377,939,911				9,805,867
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	5,511,788,780	313,718,946	4,916,445,085				281,624,748
9	Leased to Others							
10	Held for Future Use							
11	Construction Work in Progress	77,273,593	10,122,924	63,128,964				4,021,705
12	Acquisition Adjustments	182,535,184	390,002	182,145,181				
13	Total Utility Plant (8 thru 12)	5,771,597,557	324,231,872	5,161,719,230				285,646,453
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	(a)1,475,125,225	96,779,023	1,279,687,813				98,658,384
15	Net Utility Plant (13 less 14)	4,296,472,332	227,452,849	3,882,031,417				186,988,069
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,474,735,223	96,389,021	1,279,687,813				98,658,384
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant							
22	Total in Service (18 thru 21)	1,474,735,223	96,389,021	1,279,687,813				98,658,384
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	390,002	390,002					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	(a)1,475,125,225	96,779,023	1,279,687,813				98,658,384

Name of Respondent: UGI Utilities, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 12/31/2023	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedProvisionForDepreciationAmortizationAndDepletionOfPlantUtility

This amount includes ($522,361) related to Operating Leases.

(b) Concept: AccumulatedProvisionForDepreciationAmortizationAndDepletionOfPlantUtility

This amount includes ($522,361) related to Operating Leases.

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-19

Request:

Reference UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-10, concerning rate case expense. Provide the following:

A. The docket number, date of filing, and method of resolution (i.e., settlement or litigation) for each of the last three base rate cases filed with the Commission.

B. The requested rate case expense and actual rate case expense incurred for each of the base rate cases listed in response to Part A above.

C. State the Company's proposed normalization period and granted normalization period for rate case expense for each of the base rate cases listed in response to Part A above.

D. Identify the basis for the proposed normalization period for each of the base rate cases listed in response to Part C above.

Response:

A. - C. Please see Attachment I&E-RE-19.

D. The Company proposed a normalization period of one year for rate case expenses. The Company's expectation that it would file another base rate case in one year was based on the assessment of future capital requirements and continued system improvements, including those supported by the Company's Long-Term Infrastructure Improvement Plan, as well as its information technology initiatives. In addition, the Company's operating expenses are increasing, and the revenue requirements for plant additions that are not DSIC-eligible caused further pressure to file a rate case within one year after the new rates became effective. Also, capital cost rates and higher risks associated with a rate of return will reflect and be supportive of the Company's financial and risk profile. Therefore, the Company's proposed one year normalization period was reasonable at the time the rate cases were filed.

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

Attachment I&E-RE-19
T. A. Hazenstab
Page 1 of 1

UGI Utilities, Inc. - Gas Division
Prior Three Gas Base Rate Cases Filed

Docket No.	Filing Date	Method of Resolution	Rate Case Expenses		Rate Case Expense Normalization Period	
			Requested	Incurred	Proposed	Granted
R-2024-3052716	January 27, 2025	Settlement	$ 1,431,000	$ 1,072,501	1 Year	2 Years
R-2021-3030218	January 28, 2022	Settlement	$ 1,055,000	$ 855,881	1 Year	2 Years
R-2019-3015162	January 28, 2020	Settlement	$ 1,077,000	$ 1,019,432	1 Year	1 Year

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-25

Request:

Reference UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-7, concerning salaries and wages expense. State whether the Company incorporated a vacancy reserve when calculating its FPFTY claim of $82,522,000. If yes, provide a detailed calculation that reflects the vacancy reserve in the Company's labor expense FPFTY claim.

Response:

The Company used a vacancy rate of 4.7% for the Gas Division.

Please see Attachment I&E-RE-25 reflecting the vacancy reserve in the Company's labor expense FPFTY Claim.

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

Attachment I&E-RE-25
V.K. Ressler
Page 1 of 1

UGI UTILITIES, INC. - GAS DIVISION
VACANCY RATE APPLICATION
FPFTY 2027
THOUSANDS OF US $

Vacancy Rate Application

	FPFTY 2027
Salaries and Wages Expense	$ 79,484
Vacancy Rate Adjustment - 4.7%	(3,736)
	75,749
Overtime and Other Wages	5,830
	81,579
Adjustments from Exhibit A Schedule D-7 (page 1):	
Column [4] (Annualization Adjustment)	943
Total from Exhibit A, Schedule D-7 (page 1)	$ 82,522

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-24

Request:

Reference UGI Gas Book II, SDR-RR-26 concerning salaries and wages expense. Provide the following:

A. Employee counts, total and broken down by union, exempt, and non-exempt categories for FY 2023, FY 2024, the HTY, the FTY, and the FPFTY.

B. Number of employee positions that have been eliminated by month, broken down by union, exempt, and non-exempt since the commencement of the HTY and that are expected to be eliminated during the FTY and the FPFTY.

C. Vacancy rate and number of vacant positions, by month, broken down by union, exempt, and non-exempt for FY 2023, FY 2024, the HTY, the FTY, and the FPFTY.

Response:

A. Please see Attachment I&E-RE-24(A).

B. There have been no positions eliminated since the commencement of Fiscal 2025 (HTY) and there are no positions expected to be eliminated in Fiscal 2026 (FTY) or Fiscal 2027 (FPFTY).

C. Please see Attachment I&E-RE-24(C).

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

Attachment I&E-RE-24(A)
V. K. Ressler
Page 1 of 1

UGI UTILITIES, INC. - GAS DIVISION
EMPLOYEE COUNT
AS OF SEPTEMBER 30, 2023-2025 and FTY 2026 and FPFTY 2027
In FTE's

	Actual 9/30/2023	Actual 9/30/2024	Actual 9/30/2025	Budgeted* FTY 9/30/2026	Budgeted* FPFTY 9/30/2027
Union	677	661	689	683	693
Exempt	-	-	-	-	-
Non-Exempt	677	661	689	683	693
Non-Union	902	843	842	837	849
Exempt	574	539	516	512	519
Non-Exempt	328	304	326	325	330
Non-Union Temporary	7	1	2	-	-
Exempt	2	-	-	-	-
Non-Exempt	5	1	2	-	-
Total	1,586	1,505	1,533	1,520	1,541

*Includes Vacancy Rate

Attachment I-RE-24(C)
V. K. Ressler
Page 1 of 5

UGI UTILITIES, INC. - GAS DIVISION
VACANCY RATE AND VACANT POSITIONS
FISCAL YEAR 2023
In FTE's

Budgeted Postions

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23
Total	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648

Vacant Postions

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23
Union	50	45	46	48	46	36	33	33	24	25	25	31
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	50	45	46	48	46	36	33	33	24	25	25	31
Non-Union	86	89	84	79	77	73	73	36	33	28	30	33
Exempt	57	57	56	60	60	55	54	29	31	29	29	33
Non-Exempt	29	31	28	19	17	18	19	8	2	(1)	1	-
Non-Union Temporary	1	1	1	(3)	(4)	(5)	(5)	(7)	(6)	(5)	(5)	(2)
Exempt	-	-	-	-	-	-	-	-	-	-	(2)	(1)
Non-Exempt	1	1	1	(4)	(4)	(5)	(5)	(7)	(6)	(5)	(3)	(1)
Total	137	135	131	124	119	104	101	62	51	48	50	62

Vacancy %

	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23
Union	7.1%	6.4%	6.5%	6.8%	6.5%	5.1%	4.7%	4.7%	3.4%	3.5%	3.5%	4.4%
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	7.1%	6.4%	6.5%	6.8%	6.5%	5.1%	4.7%	4.7%	3.4%	3.5%	3.5%	4.4%
Non-Union	9.2%	9.5%	9.0%	8.4%	8.2%	7.8%	7.8%	3.9%	3.5%	3.0%	3.2%	3.5%
Exempt	9.4%	9.4%	9.2%	9.9%	9.9%	9.1%	8.9%	4.8%	5.1%	4.8%	4.8%	5.4%
Non-Exempt	8.8%	9.5%	8.5%	5.8%	5.2%	5.5%	5.8%	2.4%	0.6%	-0.3%	0.3%	0.0%
Non-Union Temporary	20.0%	20.0%	20.0%	-60.0%	-80.0%	-100.0%	-100.0%	-140.0%	-120.0%	-100.0%	-100.0%	-40.0%
Exempt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-200.0%	-100.0%
Non-Exempt	25.0%	25.0%	25.0%	-100.0%	-100.0%	-125.0%	-125.0%	-175.0%	-150.0%	-125.0%	-75.0%	-25.0%
Total	8.3%	8.2%	7.9%	7.5%	7.2%	6.3%	6.1%	3.8%	3.1%	2.9%	3.0%	3.8%

Attachment I-RE-24(C)
V. K. Ressler
Page 2 of 5

UGI UTILITIES, INC. - GAS DIVISION
VACANCY RATE AND VACANT POSITIONS
FISCAL YEAR 2024
In FTE's

Budgeted Postions

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
Total	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683

Vacant Postions

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
Union	42	40	34	36	37	37	45	45	51	47	54	58
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	42	40	34	36	37	37	45	45	51	47	54	58
Non-Union	48	55	62	63	66	75	78	87	99	102	105	108
Exempt	41	44	52	50	51	56	59	65	71	71	73	78
Non-Exempt	7	11	11	13	15	20	20	22	28	31	32	31
Non-Union Temporary	6	9	11	12	12	12	12	12	12	12	12	12
Exempt	(1)	-	1	1	1	1	1	1	1	1	1	1
Non-Exempt	7	9	10	11	11	11	11	11	11	11	11	11
Total	96	104	107	111	115	124	135	144	162	161	171	178

Vacancy %

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
Union	5.8%	5.6%	4.7%	5.0%	5.1%	5.1%	6.3%	6.3%	7.1%	6.5%	7.5%	8.1%
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	5.8%	5.6%	4.7%	5.0%	5.1%	5.1%	6.3%	6.3%	7.1%	6.5%	7.5%	8.1%
Non-Union	5.0%	5.8%	6.5%	6.6%	6.9%	7.9%	8.2%	9.1%	10.4%	10.7%	11.0%	11.4%
Exempt	6.7%	7.1%	8.4%	8.1%	8.3%	9.1%	9.6%	10.6%	11.5%	11.5%	11.9%	12.7%
Non-Exempt	2.1%	3.3%	3.3%	3.9%	4.5%	6.0%	6.0%	6.6%	8.4%	9.3%	9.6%	9.3%
Non-Union Temporary	46.2%	69.2%	84.6%	92.3%	92.3%	92.3%	92.3%	92.3%	92.3%	92.3%	92.3%	92.3%
Exempt	-100.0%	0.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Non-Exempt	58.3%	75.0%	83.3%	91.7%	91.7%	91.7%	91.7%	91.7%	91.7%	91.7%	91.7%	91.7%
Total	5.7%	6.2%	6.4%	6.6%	6.8%	7.4%	8.0%	8.6%	9.6%	9.6%	10.2%	10.6%

Attachment I-RE-24(C)
V. K. Ressler
Page 3 of 5

UGI UTILITIES, INC. - GAS DIVISION
VACANCY RATE AND VACANT POSITIONS
FISCAL YEAR 2025
In FTE's

Budgeted Postions

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
Total	1,572	1,572	1,572	1,587	1,587	1,587	1,593	1,593	1,593	1,595	1,595	1,595

Vacant Postions

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
Union	32	31	32	45	46	46	51	49	42	35	32	28
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	32	31	32	45	46	46	51	49	42	35	32	28
Non-Union	35	40	43	41	44	45	39	33	39	45	40	36
Exempt	43	42	42	41	45	46	49	47	49	50	51	46
Non-Exempt	(7)	(2)	1	1	(0)	(2)	(11)	(14)	(9)	(5)	(11)	(9)
Non-Union Temporary	(1)	-	-	-	-	-	-	(9)	(11)	(11)	(2)	(2)
Total	66	71	75	86	90	91	90	73	71	69	71	63

Vacancy %

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
Union	4.6%	4.5%	4.6%	6.3%	6.5%	6.5%	7.1%	6.9%	5.9%	4.9%	4.5%	3.9%
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	4.6%	4.5%	4.6%	6.3%	6.5%	6.5%	7.1%	6.9%	5.9%	4.9%	4.5%	3.9%
Non-Union	4.0%	4.6%	4.9%	4.7%	5.0%	5.1%	4.4%	3.7%	4.5%	5.1%	4.6%	4.2%
Exempt	7.6%	7.4%	7.5%	7.2%	8.0%	8.3%	8.8%	8.3%	8.6%	9.0%	9.1%	8.1%
Non-Exempt	-2.3%	-0.5%	0.2%	0.2%	-0.1%	-0.5%	-3.4%	-4.4%	-2.9%	-1.7%	-3.4%	-2.9%
Non-Union Temporary	-100%	0%	0%	0%	0%	0%	0%	-900%	-1100%	-1100%	-200%	-200%
Exempt	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Non-Exempt	-100%	0%	0%	0%	0%	0%	0%	-900%	-1100%	-1100%	-200%	-200%
Total	4.2%	4.5%	4.8%	5.4%	5.7%	5.7%	5.6%	4.6%	4.4%	4.3%	4.4%	3.9%

Attachment I-RE-24(C)
V. K. Ressler
Page 4 of 5

UGI UTILITIES, INC. - GAS DIVISION
VACANCY RATE AND VACANT POSITIONS
FISCAL YEAR 2026
In FTE's

Budgeted Postions

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26
Total	1,612	1,612	1,612	1,627	1,627	1,627	1,628	1,628	1,628	1,628	1,628	1,628

Vacant Postions

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26
Union	44	44	44	45	45	45	45	45	45	45	45	45
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	44	44	44	45	45	45	45	45	45	45	45	45
Non-Union	55	55	55	56	56	56	56	56	56	56	56	56
Exempt	34	34	34	34	34	34	35	35	35	35	35	35
Non-Exempt	21	21	21	21	21	21	21	21	21	21	21	21
Non-Union Temporary	-	-	-	-	-	-	-	-	-	-	-	-
Total	100	100	100	101	101	101	101	101	101	101	101	101

Vacancy %

	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26
Union	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
Non-Union	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
Exempt	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
Non-Exempt	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%
Total	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%

UGI UTILITIES, INC. - GAS DIVISION
VACANCY RATE AND VACANT POSITIONS
FISCAL YEAR 2027
In FTE's

Budgeted Postions

	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27
Total	1,628	1,628	1,628	1,628	1,628	1,628	1,628	1,628	1,628	1,628	1,628	1,628

Vacant Postions

	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27
Union	34	34	34	34	34	34	34	34	34	34	34	34
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	34	34	34	34	34	34	34	34	34	34	34	34
Non-Union	42	42	42	42	42	42	42	42	42	42	42	42
Exempt	26	26	26	26	26	26	26	26	26	26	26	26
Non-Exempt	16	16	16	16	16	16	16	16	16	16	16	16
Non-Union Temporary	-	-	-	-	-	-	-	-	-	-	-	-
Total	77	77	77	77	77	77	77	77	77	77	77	77

Vacancy %

	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27
Union	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Exempt	-	-	-	-	-	-	-	-	-	-	-	-
Non-Exempt	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Non-Union	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Exempt	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Non-Exempt	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Total	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%

Historical Average Vacancy Rate Calculation

		Fiscal Year 2023												
		Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	
1	Total Budgeted Positions	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	1,648	
2	Actual Vacancies	137	134	130	123	119	104	101	63	52	48	51	62	
3	**Monthly Vacancy Rate (Line 2 ÷ Line 1)**	**8.31%**	**8.13%**	**7.89%**	**7.46%**	**7.22%**	**6.31%**	**6.13%**	**3.82%**	**3.16%**	**2.91%**	**3.09%**	**3.76%**	
4	**Fiscal Year 2023 Average Vacancy Rate**													**5.68%**
		Fiscal Year 2024												
		Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	
5	Total Budgeted Positions	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	1,683	
6	Actual Vacancies	96	104	107	111	115	124	135	144	162	161	171	178	
7	**Monthly Vacancy Rate (Line 6 ÷ Line 5)**	**5.70%**	**6.18%**	**6.36%**	**6.60%**	**6.83%**	**7.37%**	**8.02%**	**8.56%**	**9.63%**	**9.57%**	**10.16%**	**10.58%**	
8	**Fiscal Year 2024 Average Vacancy Rate**													**7.96%**
		Historic Test Year												
		Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	
9	Total Budgeted Positions	1,572	1,572	1,572	1,587	1,587	1,587	1,593	1,593	1,593	1,595	1,595	1,595	
10	Actual Vacancies	66	71	75	86	90	91	89	73	70	69	70	62	
11	**Monthly Vacancy Rate (Line 10 ÷ Line 9)**	**4.21%**	**4.53%**	**4.78%**	**5.43%**	**5.68%**	**5.75%**	**5.60%**	**4.59%**	**4.41%**	**4.34%**	**4.40%**	**3.90%**	
12	**Historic Test Year Average Vacancy Rate**													**4.80%**
13	**3-Year Historic Average Vacancy Rate [(Line 4 + Line 8 + Line 12) ÷ 3]**													**6.15%**

I&E-RE-28

Request:

Reference UGI Gas Book V, Exhibit A – Fully Projected, Schedule B-4, p. 3, concerning employee pensions and benefits. Provide the following:

A. A detailed breakdown for the actual employee pensions and benefits expense incurred in FY 2023, FY 2024, and the HTY, the FTY year to date, the remaining projected FTY expense, and the FPFTY claim.

B. A breakdown of employee benefits expensed and capitalized in FY 2023, FY 2024, and the HTY, the FTY year to date, the remaining projected FTY, and the FPFTY claim for each type of benefit and broken down by union, exempt, and non-exempt.

C. A breakdown of the number of employees participating in each type of benefit in Part A by union, exempt, and non-exempt in FY 2023, FY 2024, and the HTY, the FTY year to date, the remaining projected FTY, and the FPFTY claim.

D. The total amount of wages attributable to employees participating in each benefit type in Part A, broken down by union, exempt, and non-exempt and by category of operating expense for FY 2023, FY 2024, and the HTY, the FTY year to date, the remaining projected FTY expense, and the FPFTY claim.

E. A detailed explanation with supporting documentation for the Company's determination of the changes in employee contribution levels for the FTY and FPFTY claims for each benefit in Part A above.

F. A detailed explanation with supporting documentation for the Company's determination of the changes in the number of eligible employees for the FTY and FPFTY claims for each benefit in Part A above.

Response:

A. Please see Attachment I&E-RE-28-(A).

B. Please see Attachment I&E-RE-28-(B) for a breakdown of employee benefits expensed and capitalized. System limitations do not allow for readily available ability to present this data by employee type (union, exempt, and non-exempt).

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Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-28 (Continued)

C. Please see Attachment I&E-RE-28-(C). System limitations do not allow for readily available ability to present this data by employee type (union, exempt, and non-exempt). Substantially all employees are eligible for medical, 401K, life and disability insurance and professional development. Pension and other post-employment benefits are limited to certain employees whose employment with UGI began prior to 2009.

D. System limitations do not allow for readily available ability to present this data by employee type (union, exempt, and non-exempt).

E. There was no change to the assumption of employee contribution levels for FTY compared to the HTY. A 3% increase in employee contributions was incorporated from the FTY to the FPFTY.

F. Changes to eligible employees would be based on the change in budgeted positions. No changes were made to the participation eligibility of any plans.

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

Attachment I&E-RE-28-(A)
A. M. Keller
Page 1 of 1

UGI UTILITIES, INC. - GAS DIVISION
EMPLOYEE PENSIONS AND BENEFITS IN FERC ACCOUNT 926
FOR THE YEARS ENDED SEPTEMBER 30, 2023-2025 and FTY 2026 and FPFTY 2027 and YTD 2026
Thousands of US $

	Actual Full Year 2023	Actual Full Year 2024	Actual Full Year 2025	Actual YTD January 2026	Budgeted Full Year FTY 2026	Budgeted Full Year FPFTY 2027	
Medical	$ 8,192	$ 8,660	9,385	4,385	$ 10,086	$ 10,974	
Benefits Allocated from UGI Corp	2,840	2,735	2,370	716	1,736	1,883	(a)
401K	2,910	3,388	3,367	1,129	3,587	3,799	
Pension	(1,799)	(446)	(1,773)	(26)	(1,531)	(1,531)	(b)
Life and Disability Insurance	658	684	508	135	630	662	
Professional Development	456	220	96	28	189	191	
Restricted Stock	668	73		-	-	-	(d)
PTO	(5)	-	-	-	-	-	(d)
Other Post-Employment Benefits	(1,011)	(1,427)	(1,439)	(524)	(1,419)	(1,419)	(c)
Other	539	438	756	261	786	808	
Total	13,447	14,325	13,271	6,103	14,063	15,367	

(a) Restricted Stock from UGI Corp budgeted in FERC 926 (Pensions and Benefits) but actuals flow through FERC 920 (A&G Salaries)

(b) Pension costs vary from year to year based on actuarial assumptions. The Company's claim for pension costs is based on its cash contributions (not on expense),as explained within the direct testimony of Amy M. Keller, UGI Gas Statement No. 5.

(c) Other post-employment income includes amortization of the regulatory liability along with plan actuarial earnings.

(d) Restricted Stock and PTO now flow through FERC 920 (A&G Salaries) in actuals and budget rather than through FERC 926 (Employee Pensions and Benefits).

Attachment I&E-RE-28(B)
A.M. Keller
Page 1 of 1

UGI UTILITIES, INC. - GAS DIVISION
EMPLOYEE PENSIONS AND BENEFITS
FOR THE YEARS ENDED SEPTEMBER 30, 2023-2025 and FTY 2026 and FPFTY 2027 and YTD 2026
Thousands of US $

	Actual Full Year 2023	Actual Full Year 2024	Actual Full Year 2025	Actual YTD January 2026	Budgeted Full Year FTY 2026	Budgeted Full Year FPFTY 2027	
Medical							
Expense	$ 8,192	$ 8,660	$ 9,385	$ 4,385	$ 10,086	$ 10,974	
Capital	$ 8,755	$ 7,326	$ 8,793	$ 2,296	$ 7,813	$ 8,567	
Benefits Allocated from UGI Corp							
Expense	2,840	2,735	2,370	716	1,736	1,883	(a)
Capital	-	-	-	-	-	-	
401K							
Expense	2,910	3,388	3,367	1,129	3,587	3,799	
Capital	2,916	2,852	3,060	1,050	3,005	3,178	
Pension							
Expense	(1,799)	(446)	(1,773)	(26)	(1,531)	(1,531)	(b)
Capital	(1,448)	(135)	(1,361)	(40)	(1,203)	(1,203)	
Life and Disability Insurance							
Expense	658	684	508	135	630	662	
Capital	-	-	-	-	-	-	
Professional Development							
Expense	456	220	96	28	189	191	
Capital	-	-	-	-	-	-	
Restricted Stock							
Expense	668	73					(d)
Capital	290	31					
PTO							
Expense	(5)						(d)
Capital	-						
Other Post-Employment Benefits							
Expense	(1,011)	(1,427)	(1,439)	(524)	(1,419)	(1,419)	(c)
Capital	(39)	(31)	(37)	(37)	(22)	(22)	
Other							
Expense	539	438	756	261	786	808	
Capital	66	55	49	25	68	68	

(a) Restricted Stock from UGI Corp budgeted in FERC 926 (Pensions and Benefits) but actuals flow through FERC 920 (A&G Salaries)

(b) Pension costs vary from year to year based on actuarial assumptions. The Company's claim for pension costs is based on its cash contributions (not on expense),as explained within the direct testimony of Amy M. Keller, UGI Gas Statement No. 5.

(c) Other post-employment income includes amortization of the regulatory liability along with plan actuarial earnings.

(d) Restricted Stock and PTO now flow through FERC 920 (A&G Salaries) in actuals and budget rather than through FERC 926 (Employee Pensions and Benefits).

Attachment I&E-RE-28(C)
A.M. Keller
Page 1 of 1

UGI UTILITIES, INC. - GAS DIVISION
EMPLOYEE PENSIONS AND BENEFIT PARTICIPATION
AS OF SEPTEMBER 30, 2023-2025 and FTY 2026 and FPFTY 2027

	Actual 9/30/2023	Actual 9/30/2024	Actual 9/30/2025	Budgeted 9/30/2026	Budgeted 9/30/2027
Medical	1,331	1,285	1,275	1,295	1,316
401K	1,565	1,601	1,514	1,523	1,548
Pension	458	411	382	382	382
Life and Disability Insurance	1,631	1,544	1,533	1,523	1,548
Restricted Stock	26	9	5	-	-

I&E-RE-43

Request:

Reference UGI Gas Book I Section 53.53, Attachment III-A-25, concerning advertising expenses in all accounts. Provide the following:

A. A detailed breakdown of the Public Health & Safety advertising expenses disaggregated by year and media type, listing each individual program, the account(s) in which each program is claimed, and dollar amounts claimed for each program.

B. A detailed statement of the purpose of each program and include support for why each item in Part A above is necessary for safe and reliable natural gas service.

C. A detailed breakdown of the Conservation of Energy advertising expenses disaggregated by year and media type, listing each individual program, the account(s) in which each program is claimed, and dollar amounts claimed for each program.

D. A detailed statement of the purpose of each program, including support for why each item in Part C above is necessary for safe and reliable natural gas service.

E. A detailed breakdown of the Explanation of Bill Practices, Rates, Etc. advertising expenses disaggregated by year and media type, listing each individual program, the account(s) in which each program is claimed, and dollar amounts claimed for each program.

F. A detailed statement of the purpose of each program, including support for why each item in Part E above is necessary for safe and reliable natural gas service.

G. A detailed breakdown of the Other Advertising Programs advertising expenses by year and media type, listing each individual program, the account(s) in which each program is claimed, and dollar amounts claimed for each program.

H. A detailed statement of the purpose of each program, including support for why each item in Part G above is necessary for safe and reliable natural gas service.

I&E-RE-43 (Continued)

Response:

A. Please see Attachment I&E-RE-43.

B. These programs form an integrated public safety communication plan designed to satisfy federal and state regulatory requirements, reduce incident frequency and severity, protect infrastructure from third-party damage, and serve the public interest.

Public Awareness Programs educate customers on how to recognize and respond to a natural gas leak, and reinforce the importance of calling 811 prior to excavation, through scratch 'n' sniff brochures and other print collateral. Mass Media Safety Advertising includes broad, repeated public messaging through billboards, digital display ads, and radio ads. Excavator and Pipeline Safety Outreach is a federally mandated component of pipeline safety management. Primary School Safety Education Programs teach school-age children how to respond safely to a gas emergency. Safety awareness collateral is also sent home to parents and guardians, effectively extending the program's reach to households.

C. Please see Attachment I&E-RE-43.

D. Fuel Conversion Programs and Customer Newsletters support the Company's obligation to promote the efficient and economical use of natural gas on behalf of all ratepayers.

Fuel conversion marketing campaigns encourage customers to switch from less efficient energy sources to natural gas, broadening the customer base and distributing fixed infrastructure costs across more users — directly reducing the per-customer cost of maintaining and operating the distribution system.

Customer newsletters deliver energy savings tips and information about efficiency programs that help customers reduce consumption and manage their bills. A customer base that uses natural gas efficiently supports more stable and cost-effective system operations.

E. Please see Attachment I&E-RE-43.

F. These programs primarily support the Company's obligation to keep customers informed of their rights, responsibilities, and the terms under which natural gas service is provided.

I&E-RE-43 (Continued)

Newsprint rate change notices and bill inserts for rate changes ensure that customers receive timely, accessible notification of adjustments to their rates.

Bill inserts covering customer rights and responsibilities reinforce the terms of service and help customers understand available protections, reducing the likelihood of service interruptions and associated costs. Bill inserts covering infrastructure notices — including reminders about customer-owned fuel lines and excess flow valves — inform customers of their maintenance obligations and the safety features built into their service, reducing the risk of incidents attributable to neglected customer-side infrastructure.

G. Please see Attachment I&E-RE-43.

H. Community Event Sponsorships and Stakeholder Communications support the Company's ability to maintain productive relationships with the communities, regulators, and governmental entities it serves.

Community Event Sponsorships are a strategic investment that directly advances the interests of ratepayers and the long-term health of the utility system. Through targeted sponsorship opportunities, UGI promotes the benefits of domestic natural gas, energy conservation, and the responsible development of natural gas as a fuel source. These efforts are carried out across a variety of channels including special events, program advertisements, website displays, and printed collateral. All of which serve to educate the public and expand awareness of natural gas as an affordable, efficient, and domestically available energy option.

Stakeholder newsletters provide regulators, legislators, and other governmental stakeholders with regular communication about the Company's customer and community programs, operations, safety initiatives, and infrastructure investments. These stakeholders serve as important secondary channels for public outreach, as they are well-positioned to share the Company's messaging with their constituents.

This category also includes a small number of expenditures related to customer assistance program promotion that are more properly classified elsewhere, representing less than 1% of the total and included here for reconciliation purposes only.

UGI UTILITIES - GAS DIVISION
ADVERTISING EXPENSES BY PROGRAM, MEDIA TYPE AND YEAR AND ACCOUNT
FISCAL YEARS 2023 - 2027

A. Public Health & Safety

Media Type	Program	FY2023	FY2024	FY2025	FY2026	FY2027	Accounts
Print/Digital	*Public Awareness Programming*	*$ 24,703*	*$ 176,077*	*$ 263,843*	*$ 303,132*	*$ 323,733*	
	Mass Media Safety Advertising Placements	*$ -*	*$ 227,763*	*$ 99,708*	*$ 53,992*	*$ 54,992*	8920, 9090
	Excavator and Pipeline Safety Outreach/Programming	*$ -*	*$ 49,152*	*$ 14,154*	*$ 22,500*	*$ 22,500*	
	Total	$ 24,703	$ 452,992	$ 377,705	$ 379,624	$ 401,225	
Radio	*Mass Media Safety Advertising Placements*	*$ -*	*$ 50,986*	*$ 85,912*	*$ 176,400*	*$ 176,400*	9090
	Total	$ -	$ 50,986	$ 85,912	$ 176,400	$ 176,400	
Bill Insert	*Public Awareness Programming*	*$ -*	*$ 472,874*	*$ 287,946*	*$ 303,891*	*$ 321,183*	8920, 9090
	Total	$ -	$ 472,874	$ 287,946	$ 303,891	$ 321,183	
Other	*Excavator and Pipeline Safety Outreach/Programming*	*$ 200*	*$ 48,750*	*$ -*	*$ 110,160*	*$ 101,916*	
	Mass Media Safety Advertising Placements	*$ -*	*$ -*	*$ 58,023*	*$ -*	*$ -*	8920, 9090
	Primary School Safety Education Program	*$ -*	*$ -*	*$ 77,483*	*$ 87,500*	*$ 90,000*	
	Total	$ 200	$ 48,750	$ 135,506	$ 197,660	$ 191,916	
	GRAND TOTAL	$ 24,903	$ 1,025,602	$ 887,069	$ 1,057,575	$ 1,090,724	

C. Conservation of Energy

Media Type	Program	FY2023	FY2024	FY2025	FY2026	FY2027	Accounts
Print/Digital	*Conversion Advertising Campaign*	*$ 83,604*	*$ 72,161*	*$ 235,414*	*$ 240,467*	*$ 244,000*	8920, 9030,9090, 9100, 9130, 9210, 9302
Bill Insert	*Customer Newsletters*	*$ 21,770*	*$ 879*	*$ -*	*$ 26,733*	*$ 28,515*	
	Total	$ 105,374	$ 73,040	$ 235,414	$ 267,200	$ 272,515	

E. Explanation of Bill Practices

Media Type	Program	FY2023	FY2024	FY2025	FY2026	FY2027	Accounts
Print/Digital	*Newsprint Rate Change Notices*	*$ 36,964*	*$ 26,669*	*$ 35,983*	*$ 36,298*	*$ 37,350*	9030, 9090, 9302
Bill Insert	*Rate Change,Reminder of Rights, Infrastructure Notices*	*$ 342,186*	*$ 151,608*	*$ 130,844*	*$ 269,993*	*$ 280,320*	
	Total	$ 379,150	$ 178,277	$ 166,827	$ 306,291	$ 317,671	

G. Other Advertising Programs

Media Type	Program	FY2023	FY2024	FY2025	FY2026	FY2027	Accounts
Other	*Community Event Sponsorships*	*$ 486,098*	*$ 242,799*	*$ 152,974*	*$ 168,655*	*$ 191,149*	8870, 8920, 9030, 9090, 9130, 9210, 9301, 9302
	Stakeholder Newsletters	*$ 163,130*	*$ 127,006*	*$ 130,784*	*$ 190,124*	*$ 189,249*	
Bill Insert/Radio	*Customer Programs Outreach*	*$ 15,916*	*$ -*	*$ 2,995*	*$ -*	*$ -*	
	Total	$ 665,144	$ 369,805	$ 286,752	$ 358,779	$ 380,397	

I&E-RE-44

Request:

Reference the Company's response to I&E-RE-9, Parts C and D, and Attachment to I&E-RE-9.2, pp. 1-6 and UGI Gas Book I Section 53.53, Attachment III-A-25 concerning advertising expenses in all accounts. Provide the following:

A. All advertising publications, disaggregated by year, for each advertising expense category by type, including, but not limited to, brochures, notices, bill inserts, maintenance tips, and publications provided to customers under each of these advertising programs included on UGI Gas Book I Section 53.53, Attachment III-A-25.

B. For any audio or visual moving advertising in Part A above, in lieu of the advertising publication, provide a transcript of each program.

C. All advertising publications, disaggregated by year, that are posted on billboards, displayed in/on sports arenas, or that use any other form of mass marketing included on UGI Gas Book I Section 53.53, Attachment III-A-25.

D. For any audio or visual moving advertising in Part C above, in lieu of the advertising publication, provide a transcript of each program.

E. For Parts A and C above, state the dollar amount claimed for each publication.

Response:

A - D. Please see Attachment I&E-RE-44 provided as a separate attachment.

E. Please see Attachment I&E-RE-43.

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

Program	Media Type	Page Number(s)
Public Awareness Programming	Print/Digital	2 – 12
Mass Media Safety Advertising Placements	Print/Digital	13 – 39
Excavator and Pipeline Safety Outreach/Programming	Print/Digital	40 - 41
Mass Media Safety Advertising Placements	Radio	42 – 44
Public Awareness Programming	Bill Insert	45 – 46
Excavator and Pipeline Safety Outreach/Programming	Other	47 – 155
Mass Media Safety Advertising Placements	Other	156 - 157
Primary School Safety Education Program	Other	158 – 166
Conversion Advertising Campaign	Print/Digital	167 - 203
Customer Newsletters	Bill Insert	204 – 247
Newsprint Rate Change Notices	Print/Digital	248 - 310
Rate Change, Reminder of Rights, Infrastructure Notices	Bill Insert	311 – 324
Community Event Sponsorships	Other	325 - 329
Stakeholder Newsletters	Other	330 – 425
Customer Programs Outreach	Bill Insert	426 - 427

UGI UTILITIES, INC. – TITLE SPONSOR

CATEGORIES

- Advocacy
- Ambassadors
- Blog
- Development in Focus
- Economic Development
- Events
- Family Busines Alliance
- Financing
- General News
- Industry & Workforce
- Membership
- Training
- Uncategorized
- Women2Women

UGI Utilities, Inc is proud to provide ongoing support to Women2Women. We recognize the important role this program plays in advancing women's roles in leadership in the workplace, providing a safe place for feedback and encouragement, and the engagement of women to further equality for all.

UGI recently launched the BIDE (Belonging, Inclusion, Diversity and Equality) Imperative, which was created to enhance and expand our efforts to be part of the solution in addressing systemic racism and injustice in our communities. As part of BIDE, UGI provides support and coordination through Employee Resource Groups, such as the Women's Impact Network (WIN). WIN is focused on fostering an enriched environment to recruit, retain, develop and advance our female and minority leaders within the UGI Family of Companies.

UGI Utilities, Inc. is proud to provide energy to over 700,000 homes and business across Pennsylvania. We have been a part of our communities for over a century, with tens of thousands of miles of infrastructure underground or overhead. Our support for our communities doesn't end there – UGI and its employees invest hundreds of thousands of dollars every year to lifesaving programs like the American Red Cross Home Fire Campaign and organizations like Girl Scouts, which ensure a better future for us all. In addition, our employees volunteer thousands of hours with local fire departments, youth athletics, various non-profit boards and committees, and countless other organizations that are making a difference in our communities every day. At UGI, we are glad to do our part to make the areas we serve a great place to live and work.

UGI Utilities, Inc. is a natural gas and electric utility headquartered in Denver, Pennsylvania, serving more than 730,000 customers in 45 Pennsylvania counties and one county in Maryland. The company is a wholly-owned subsidiary of UGI Corporation, based in Valley Forge.

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5 Landmark Homes 112 Wyndale Dr.
6 Landmark Homes 250 Dahlia Cir.
7 Murry Communities 136 Stillcreek Road
9 Pine Hill Building Co. 837 Wheatfield Ln.
10 Keystone Custom Homes 104 Cameron St.
11 EC Custom Homes 293 Sarsen Dr.
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15 EGSolitaTus Homes 2482 Spring Water Cir.
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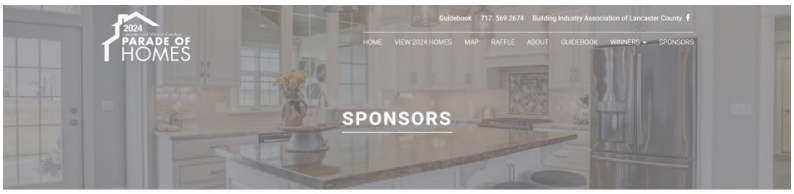

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"Here at Fulton Bank, we continue to be strong, longtime supporters of the BIA and our local homebuilder community.

We are proud to support so many of the companies who are members of the BIA, and many of the builders who have entered homes into the Parade.

While the market has its peaks and valleys, one constant remains: Fulton Bank's commitment to the industry and our homebuilder customers."

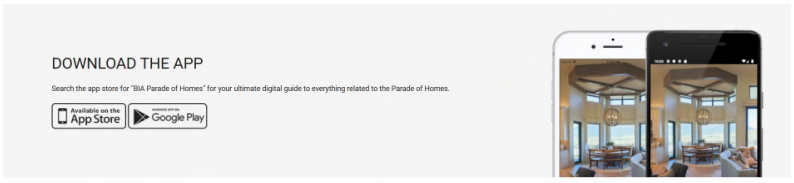
UGI

Energy to do more®

"Why we, UGI, sponsor the Parade of Homes.

We recognize the benefits that the Parade provides to the community, to homeowners, and to homebuyers.

UGI has sponsored the Parade of Homes for over 20 years, so you can see our partnership with the BIA of Lancaster County and the support of the builders and associates in this region is a long term commitment."



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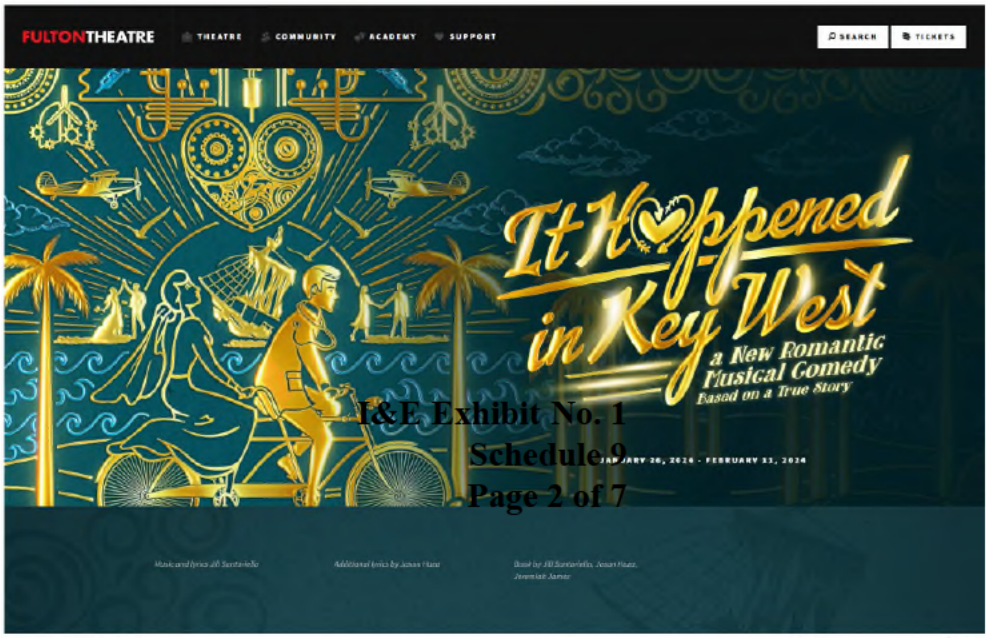

I&E Exhibit No. 1
Schedule 9
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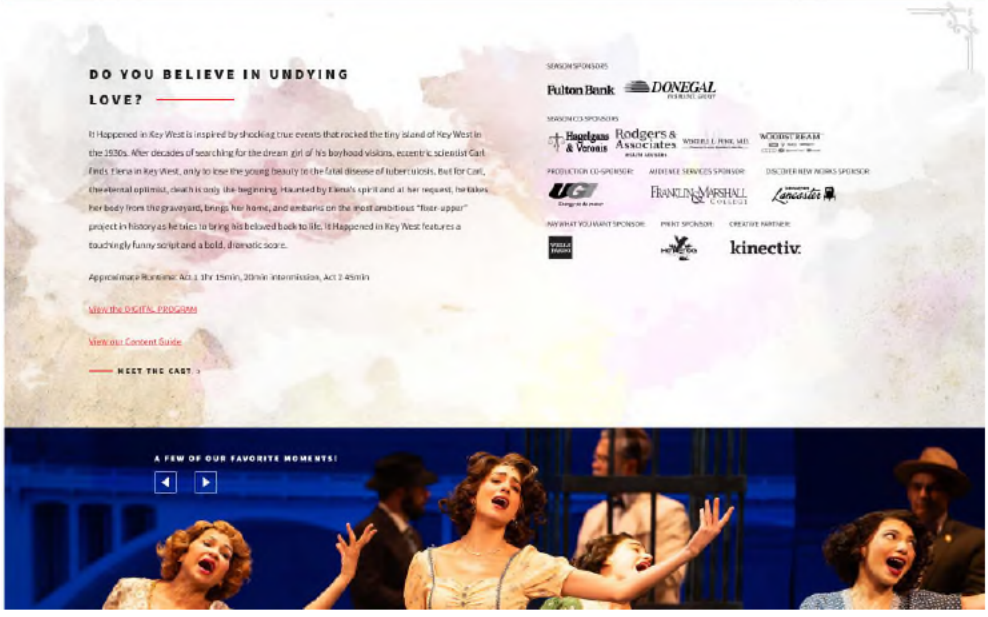

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UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-14

Request:

Reference UGI Gas Book II, SDR-RR-30, concerning employee activity costs. Provide the following:

A. The employee activity costs incurred in FY 2023, FY 2024, the HTY, and projected for the FTY.

B. A detailed explanation for any increases by fiscal year in the employee activity costs from the HTY through the FPFTY.

C. A detailed breakdown of the FPFTY claimed employee activity costs of $583,036.

D. A detailed explanation for why each item in the response to Part C above is necessary for safe and reliable natural gas service.

Response:

A. Please see Attachment I&E-RE-14.

B. The overall increase of $228,998 from FY2024 to FY2025 is driven mainly by reinstatement of the annual company picnic in 2025. The service/safety awards were lower than typical in 2024 due to a one-time true-up reduction in expense as the Company discontinued awards associated with health incentive program (approximately $80,000). The increase from 2025 to 2026 (FTY) is due to restoration of a more normal amount of department meetings and employee engagement activities. The increase from 2026 (FTY) to 2027 (FPFTY) is due to an expected pricing increase for the Company picnic.

C. Please see Attachment I&E-RE-14.

D. UGI Gas uses employee activities and awards to boost morale, promote team building, and foster a positive work environment. These activities and awards all have a similar goal – recognizing and celebrating employees for meeting milestones and for outstanding performance, which leads to increased employee engagement, productivity, and retention.

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-14 (Continued)

Each of these items recognizes employees for their contributions to the service provided by UGI Gas to its customers and communities. Such recognition can help motivate and retain UGI Gas employees to continue to improve upon the Company's track record of providing safe and reliable service to its customers.

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

Attachment I&E-RE-14
V. K. Ressler
Page 1 of 1

UGI UTILITIES, INC. - GAS DIVISION
Employee Activity Cost
For the 12 Months Ending September 30,

	2023 Actual	2024 Actual	2025 HTY	2026 FTY	2027 FPFTY
Company Picnic	$ 159,944	$ -	$ 177,136	$ 175,000	$ 195,000
Safety/Service Awards	$ 195,298	$ 127,902	$ 215,177	$ 232,898	$ 232,898
Other Activities*	$ 245,630	$ 133,129	$ 97,716	$ 152,328	$ 155,138
Total Employee Activity	$ 600,872	$ 261,031	$ 490,029	$ 560,226	$ 583,036

*Other Activities include, but are not limited to department meetings, employee engagement activities and field employee welfare (water, ice, etc.).

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-13

Request:

Reference UGI Gas Book II, Attachment SDR-RR-30, concerning membership dues. Provide the following:

A. Identify the account name and number where membership dues are claimed in the FPFTY.

B. A similar schedule for FY 2023, FY 2024, the HTY, the FTY year-to-date, and the projected FTY.

C. A detailed explanation for any increases by fiscal year from FY 2023 through the FPFTY.

D. A detailed breakdown by payee and amount of the $6,823 for payments to organizations of $1,500 or under.

E. For each payee identified in response to Part C above, identify the expense amount incurred in FY 2023 through the FTY year-to-date, and forecasted for the FTY.

F. A detailed explanation for why the payment to each payee identified in Attachment SDR-RR-30 and in response to Part A above is necessary for safe and reliable natural gas distribution service.

Response:

A. The majority of memberships are claimed in 9302 - Miscellaneous General Expenses, with the exception of Pipeline Association for Public Awareness, which is claimed in 9301 - General Advertising Expenses.

B. Please see Attachment I&E-RE-13.1.

C. Increases are due to costs to retain memberships.

D. Please see Attachment I&E-RE-13.1.

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-13 (Continued)

E. Please see Attachment I&E-RE-13.1. Forecast is equal to Projected for the period March - September of Fiscal 2026 (FTY). "FPY - YTD" is the first five months of Fiscal 2026 (actuals for Oct. 2025 through Feb. 2026). "FPY - Projected" is the remaining seven months of Fiscal 2026 (projected for March 2026 through Sept. 2026). Together "FPY - YTD" and "FPY - Projected" total Fiscal 2026.

F. Please see Attachment I&E-RE-13.2.

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

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF COMPANY MEMBERSHIPS
FOR THE FISCAL YEARS 2023-2027

Attachment I&E-RE-13.1
V. K. Ressler
Page 1 of 1

Organization Name	2023	2024	2025	FTY - YTD** 2026	FTY - Projected 2026	FPFTY 2027	
AMERICAN GAS ASSOCIATION	769,436	662,797	722,304	183,361	553,133	779,316	*
GAS TECHNOLOGY INSTITUTE	25,000	6,250	344,500	344,500	21,746	371,457	
ENERGY ASSOCIATION OF PA	161,744	174,374	206,938	-	201,402	216,732	*
NORTHEAST GAS ASSOCIATION	55,000	57,750	80,649	57,750	710	59,419	
ECONOMIC DEVELOPMENT OF LANCASTER	33,000	24,750	37,080	25,000	7,500	32,500	
PA CHAMBER OF BUSINESS AND INDUSTRY	28,713	30,175	63,350	25,000	4,278	30,733	*
ENERGY SOLUTIONS CENTER	19,380	-	20,800	21,500	-	21,500	
LEHIGH VALLEY ECONOMIC DEVELOPMENT CORP	20,000	20,000	20,000	7,500	12,500	20,000	
GREATER READING ECONOMIC PARTNERSHIP	14,500	14,500	14,880	15,287	-	15,000	
LEBANON VALLEY ECONOMIC DEVELOPMENT CORP	7,500	7,500	7,500	7,500	-	7,500	
WYOMING VALLEY CHAMBER OF COMMERCE	7,000	7,000	2,145	1,000	6,000	7,000	
PENN NORTHEAST - GAS DIVISION	5,500	5,500	5,500	-	5,500	5,500	
BETHLEHEM ECONOMIC DEVELOPMENT CORP	5,500	2,500	2,500	-	5,000	5,000	
SCRANTON CHAMBER OF COMMERCE	5,000	3,000	3,000	-	3,750	3,750	
WYOMING COUNTY CHAMBER OF COMMERCE	5,000	2,150	2,145	1,000	1,145	2,500	
GREATER SUSQUEHANNA CHAMBER OF COMM	5,000	2,050	2,050	2,224	-	2,500	
PIPELINE ASSOCIATION FOR PUBLIC AWARENESS	1,647	1,647		1,840	660	2,500	
HARRISBURG REGIONAL CHAMBER & CREDC	1,739	1,738	1,790	-	1,790	2,000	
WEDCO - WAYNE ECONOMIC DEVELOPMENT COMPANY	5,000	-	1,500	-	1,750	1,750	
ERM CONSULTING & ENGINEERING INC.	5,625	-	-	-	-	-	
MIDWEST ENERGY ASSOCIATION	4,360	-	-	-	-	-	
NORTHEASTERN PENNSYLVANIA ALLIANCE	1,655	-	-	-	-	-	
OUR NATIONS ENERGY FUTURE COALITION	12,500	-	-	-	-	-	
ALLENTOWN ECONOMIC DEVELOPMENT CORP.	5,000	-	-	-	-	-	
THE COALITION FOR RENEWABLE NATURAL GAS	20,400	-	-	-	-	-	
					-		
ORGANIZATIONS $1,500 & UNDER (IN CLAIM YEAR FY27):					-		
FOCUS CENTRAL PENNSYLVANIA - NORTH	3,000	1,500	1,500	-	1,500	1,500	
HBA OF METROPOLITAN HARRISBURG	655	1,488	6,498	5,000	-	1,498	
LANCASTER CHAMBER OF COMMERCE	1,100	1,200	1,236	-	1,236	1,250	
THE GREATER CARBONDALE CHAM OF COMMERCE	500	-	500	-	500	750	
SHIPPENSBURG AREA CHAMBER OF COMM	479	-	541	562	-	541	
WILLIAMSPORT/LYCOMING CHAM OF COMM	-	500	500	-	500	500	
DEVELOP TIOGA	500	500	500	-	500	500	
CARLISLE CHAMBER MEMBERSHIP	-	-	-	-	284	284	
Total	$ 1,231,432	$ 1,028,870	$ 1,549,906	$ 699,024	$ 831,384	$ 1,593,479	

* Excludes lobbying portion of dues.
** For the five month ending February 28, 2026

UGI UTILITIES, INC. - GAS DIVISION
EXPLANATION OF REQUEST I&E-RE-13 PART F

Organization Name	Explanation
American Gas Association	Provides industry safety standards, engineering codes, and federal regulatory advocacy (DOT/PHMSA compliance) governing pipeline design, operation, and maintenance. Ensures the utility meets or exceeds federal pipeline safety requirements, directly reducing the risk of incidents and service disruptions for customers.
Gas Technology Institute	Funds and provides access to R&D on pipeline integrity, leak detection, system efficiency, and infrastructure modernization technologies. Enables adoption of new technologies that improve reliability, reduce outages, and lower operating costs .
Energy Association of Pennsylvania	Focuses on creating a collaborative environment to support support sharing of utility best practives and to address customer affordability matters.
Northeast Gas Association	Provides a regional forum on pipeline capacity, winter peaking reliability, emergency mutual aid, and regulatory issues specific to the Northeastern U.S. market. Strengthens regional energy security and service reliability during peak demand periods, reducing the risk of supply interruptions for PA customers.
Economic Development of Lancaster	This membership supports UGI Gas's ability to monitor and respond to business growth and development trends throughout Lancaster County. Awareness of planned commercial and industrial expansion enables the Company to proactively plan distribution system investments necessary to serve new and growing load. Broader customer base spreads fixed infrastructure costs more widely, supporting long-term rate stability for all customers.
PA Chamber of Business and Industry	Provides a statewide business advocacy forum supporting sound energy and regulatory policy in Pennsylvania's legislative and regulatory environment. Promotes a stable policy environment that supports infrastructure investment, workforce development, and reliable energy supply for businesses and residents.
Energy Solutions Center	Promotes efficient end-use natural gas technologies through demonstrations and programs for commercial and industrial customers. Helps customers access cost-effective gas equipment and efficiency improvements, lowering energy bills and supporting economic competitiveness.
Lehigh Valley Economic Development Corp	Supports commercial and industrial development in the Lehigh Valley, driving new gas customer additions and strengthening regional economic activity. Growing the customer base in the Lehigh Valley improves system economics and supports infrastructure investment that benefits all customers in the region.
Greater Reading Economic Partnership	Drives economic development and business attraction in the Greater Reading area, supporting gas customer growth and system utilization. New customer additions in the Reading area improve cost allocation and support continued infrastructure investment serving existing customers.
Lebanon Valley Economic Development Corp	Supports business development and industrial recruitment in Lebanon Valley, growing the natural gas customer base in the service territory. Increased system utilization from new customers contributes to rate stability and long-term affordability for existing customers.
Wyoming Valley Chamber of Commerce	Connects the utility with the Wyoming Valley business community, supporting customer development and community relationships in Northeastern PA. Strengthens local economic activity and new customer growth, supporting the utility's ability to invest in safe, reliable infrastructure in the region.
Penn Northeast – Gas Division	Regional economic development organization focused on attracting industrial and commercial gas customers to Northeastern Pennsylvania. Industrial and commercial load additions improve system load factors and help support cost-effective service for residential and small commercial customers.

Organization Name	Explanation
Bethlehem Economic Development Corp	Supports economic development and business attraction in the City of Bethlehem, driving new gas service connections and system growth. New business development in Bethlehem supports customer growth that contributes to rate base health and long-term rate stability.
Scranton Chamber of Commerce	Connects the utility with the Scranton-area business community, supporting customer retention, new business attraction, and community relationships. Active engagement in Scranton supports economic growth and new gas customer additions in one of the utility's key northeastern service areas.
Wyoming County Chamber of Commerce	Provides a forum for engaging with Wyoming County businesses and community leaders, supporting local economic development and customer relations. Supports new customer opportunities and community goodwill in Wyoming County, reinforcing the utility's commitment to rural service territories.
Greater Susquehanna Chamber of Commerce	Engages with businesses and community stakeholders in the Susquehanna region, supporting economic development and gas service growth. Promotes local business development and new customer connections in the Susquehanna Valley service area.
Pipeline Association for Public Awareness	Dedicated to pipeline safety education for customers, excavators, municipalities, and first responders; supports PA 811 'Call Before You Dig' damage prevention programs. Reduces third-party pipeline damage — the leading cause of gas incidents — directly protecting public safety, property, and service continuity for all customers.
Harrisburg Regional Chamber & CREDC	Connects the utility to Central Pennsylvania's business and economic development community, supporting new customer growth and infrastructure investment advocacy. Supports commercial and industrial development in the Harrisburg region, growing the customer base and promoting long-term rate stability.
WEDCO – Wayne Economic Development Company	Supports economic development in Wayne County, attracting businesses and supporting new gas service connections in a rural service area. Business development in Wayne County supports new customer additions, helping spread infrastructure costs and maintain service in rural communities.
Focus Central Pennsylvania – North	Promotes business development and economic growth in Central Pennsylvania's northern counties, supporting gas customer additions in the service territory. New commercial and industrial connections in north-central PA support system growth and help maintain affordable service for existing customers.
HBA of Metropolitan Harrisburg	Home Builders Association engagement supports new residential construction and gas service connections throughout the greater Harrisburg market. New residential construction drives gas service extensions and customer additions, supporting infrastructure investment and long-term system sustainability.
Lancaster Chamber of Commerce	Provides engagement with Lancaster County's large and diverse business community, supporting customer development and community relationships. Strengthens the utility's relationships with one of its major service areas, supporting business
The Greater Carbondale Chamber of Commerce	Connects the utility with businesses and community leaders in the Carbondale area, supporting local economic development and customer relationships. Promotes new customer development and community engagement in the Carbondale service area of Northeastern Pennsylvania.
Shippensburg Area Chamber of Commerce	Supports business development and community engagement in the Shippensburg area, connecting the utility with local commercial customers. Supports new customer connections and community relations in Cumberland County, reinforcing the utility's presence in south-central PA.

UGI UTILITIES, INC. - GAS DIVISION
EXPLANATION OF REQUEST I&E-RE-13 PART F

Organization Name	Explanation
Williamsport/Lycoming Chamber of Commerce	Engages with the business community in the Williamsport and Lycoming County area, a key portion of the utility's northcentral PA service territory. Promotes economic development and new gas customer additions in Lycoming County, supporting system growth and long-term customer affordability.
Develop Tioga	Economic development organization for Tioga County supporting business attraction and job creation in a rural area of the service territory. Supports new customer growth in Tioga County, helping to sustain infrastructure investment and reliable service in a rural portion of the service territory.
Carlisle Chamber Membership	Connects the utility with the Carlisle business community in Cumberland County, supporting commercial customer relationships and local economic development. Promotes new business development and customer growth in the Carlisle area, contributing to system utilization and rate base health.

Report to the Pennsylvania Public Utility Commission

UGI Utilities, Inc. – Gas Division
Energy Efficiency and Conservation Plan
Phase I Program Year 6 (FY2025)
October 1, 2024 - September 30, 2025

Prepared by UGI Utilities, Inc. - Gas Division
Filing Date: 01/31/26

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1 EXECUTIVE SUMMARY

This Annual Report covers the sixth year of Phase I of the UGI Utilities, Inc.– Gas Division's (UGI Gas or the Company) Energy Efficiency and Conservation (EE&C) Plan, which was approved as part of UGI Gas's 2019 Rate Case (Docket No. R-2018-3006814). On February 7, 2024, UGI Gas filed a petition requesting a one-year extension of the Phase I EE&C Plan. This petition was approved by the Pennsylvania Public Utility Commission (Commission) on March 14, 2024, creating a sixth year in Phase I that replicates the budgets and goals for FY2024. On April 15, 2024, UGI Gas filed its petition for approval of its Phase II EE&C Plan covering the time period of October 1, 2025-September 30, 2030, was approved on July 24, 2025, at Docket No. M-2024-3048418. Phase I Program Year 6 (FY2025) covers the period of October 1, 2024, through September 30, 2025. As highlighted below, the EE&C Plan continues to deliver cost-effective savings on a portfolio-wide basis:

- Costs for the EE&C Portfolio (including Combined Heat and Power (CHP)) were $10.4 million, or 75% of budgeted annual costs. Excluding CHP, the Energy Efficiency (EE) programs spent $10.4 million, or 80% of budgeted annual costs.
- Savings for the EE programs (excluding CHP) were 241,250 MMBtus, or 85% of projections.
- The EE programs (excluding CHP) provided $24 million in present value of net benefits to customers with a benefit-to-cost ratio (BCR) of 2.81 as calculated under the Total Resource Cost (TRC) Test, including Demand Reduction Induced Price Effect (DRIPE) and the market price for CO_2. Under the TRC Test without DRIPE and CO_2, the EE programs provided $13.5 million in present value of net benefits to customers with a BCR of 2.02.
- The Nonresidential Custom (NC) Program spent 100% of budget and achieved 206% of projected annual MMBtu savings, with a BCR of 2.89 (including DRIPE and CO_2). Electricity savings were also high, with MWh savings at 462% of projections.
- The Residential Prescriptive (RP) Program achieved 78% of projected savings and a BCR of 2.32 while spending 80% of budget.
- Phase-to-date performance, which represents the entirety of the original Phase I EE&C Plan plus the one-year extension, includes savings of 1,463,281 MMBtus, or 94% of plan projections, direct utility costs of $62.5 million, or 81% of projections, and customer incentives of $47.7 million, or 84% of projections.

value of net benefits, with a BCR of 2.02. The following tables provide a high-level overview of the EE&C Portfolio's spending and savings for FY2025.

Table 1. EE&C PORTFOLIO SUMMARY - FY2025			
Component (Nominal $)	**Actual**	**Budget**	**%**
Portfolio Spending	**$10,387,378**	**$13,903,600**	**75%**
EE Program	$10,374,836	$13,001,100	80%
CHP Program	$12,543	$902,500	1%
EE Program Natural Gas Savings			
Annual (MMBtus)	241,250	284,865	85%
Lifetime (MMBtus)	4,814,357	5,685,105	85%
CHP Net Primary Energy Savings			
Annual (MMBtus)	0	396,905	0%
Lifetime (MMBtus)	0	5,953,578	0%

Table 2. EE&C PORTFOLIO SUMMARY - PHASE			
Component (Nominal $)	**Actual**	**Budget**	**%**
Portfolio Spending	**$62,516,825**	**$77,273,200**	**81%**
EE Program	$61,922,054	$72,928,200	85%
CHP Program	$ 594,771	$4,345,000	14%
EE Program Natural Gas Savings			
Annual (MMBtus)	1,463,281	1,564,412	94%
Lifetime (MMBtus)	29,316,244	31,142,900	94%
CHP Net Primary Energy Savings			
Annual (MMBtus)	140,246	2,152,652	7%
Lifetime (MMBtus)	2,804,915	32,289,781	9%

2.2.1 Summary of Program Costs

Table 3. EE&C PORTFOLIO COSTS AND PARTICIPATION BY PROGRAM - FY2025				
Program	**Total**	**Incentive**	**Non-Incentive**	**Customers***
Residential Prescriptive (RP)	$5,191,708	$4,744,328	$447,380	7,512
Nonresidential Prescriptive (NP)	$170,744	$156,453	$14,291	41
Residential Retrofit (RR)	$481,836	$191,117	$290,718	351
Residential New Construction (RNC)	$1,851,518	$1,143,253	$708,265	1,361
Nonresidential Custom (NC)	$1,863,588	$1,427,400	$436,188	43
Portfolio Wide (PW)	$815,441	$0	$815,441	0
Energy Efficiency Total	**$10,374,836**	**$7,662,552**	**$2,712,284**	**9,308**
Combined Heat and Power (CHP)	$12,543	$0	$12,543	0
Portfolio Total	**$10,387,378**	**$7,662,552**	**$2,724,827**	**9,308**

***Represents unique customers who have received a rebate.**

2.2.2 Summary of Program Savings

Table 4. ENERGY EFFICIENCY PROGRAM SAVINGS - FY2025							
Program	**Natural Gas (MMBtu)**		**Electric Energy (MWh)**		**Capacity**	**Water Savings (Gal)**	
	Annual	**Lifetime**	**Annual**	**Lifetime**	**MW-yr.**	**Annual**	**Lifetime**
Residential Prescriptive	108,620	2,102,196	402.7	4,429.20	0.090	0	0
Nonresidential Prescriptive	5,354	91,925	2.3	27.1	0.000	453,144	6,617,740
Residential Retrofit	3,211	89,220	37.0	1,134.6	0.021	929,888	9,638,358
Residential New Construction	34,634	796,591.9	4,187.6	96,315.1	1.013	1,431,892	32,933,516
Nonresidential Custom	89,430	1,734,424	210.5	3,752.8	0.096	0	0
UGI Internal Staff, Program Setup & Development	0	0	0.0	0.0	0.000	0	0
Energy Efficiency Total	**241,250**	**4,814,357**	**4,840.1**	**105,658.9**	**1.221**	**2,814,924**	**49,189,614**

3.1.4 Residential Prescriptive Program Results

Table 13. PROGRAM COSTS			
Component (Nominal $)	**FY2025 - Actual**	**FY2025 - Budget**	**%**
Direct Utility Costs	**$ 5,191,708**	**$ 6,494,900**	**80%**
Customer Incentives	$4,744,328	$ 6,078,900	78%
Administration	$146,596	$ 167,000	88%
Marketing	$222,523	$ 145,000	153%
Inspections	$78,260	$ 104,000	75%
Evaluations	$0	$ 0	0%
Incremental Participant Costs	**$5,172,618**	**$4,338,626**	**119%**

Table 14. PROGRAM SAVINGS			
Type	**FY2025 - Actual**	**FY2025 - Projected**	**%**
Natural Gas (MMBtus)			
Annual	108,620	139,642	78%
Lifetime	2,102,196	2,703,996	78%
Electric Energy (MWh)			
Annual	402.7	84.0	479%
Lifetime	4,429.2	924.4	479%
Capacity Savings (MW)	0.090	0.000	100%
Water Savings (Gallons)			
Annual	0	0	100%
Lifetime	0	0	100%

Table 15. PROGRAM COST-EFFECTIVENESS (BASE CASE + DRIPE & CO2) PV Year (2018)		
Benefits/Cost Component	**FY2025**	**Phase**
TRC NPV Benefits	$14,993,069	$113,469,336
TRC NPV Costs	$6,467,530	$50,438,243
TRC Net Benefits	$8,525,539	$63,031,092
TRC Benefit/Cost Ratio	**2.32**	**2.25**

Table 16. PROGRAM COST-EFFECTIVENESS (BASE CASE) PV Year (2018)		
Benefits/Cost Component	**FY2025**	**Phase**
TRC NPV Benefits	$11,334,739	$86,423,084
TRC NPV Costs	$6,467,530	$50,438,243
TRC Net Benefits	$4,867,209	$35,984,840
TRC Benefit/Cost Ratio	**1.75**	**1.71**

total of nine events were held, four of which fell within FY2025. UGI also exhibited at three distributor trade events and presented at AEE and ASHRAE events.

3.2.2.2 Inspection and Evaluation Activity

Inspections were performed by AM Conversation to confirm that the equipment on the rebate application matched the equipment that was installed in the customer's business. In FY2025, three inspections were completed and all projects passed.

In FY2025, $0 was spent on evaluation activities against an initial filed budget of $0.

3.2.3 Program Updates for FY2025

There were no program updates for FY2025. However, in response to continued underperformance by this program, the NP incentives have been combined with the Nonresidential Custom rebates for the next phase of the UGI EE&C Program, and the implementation of both pathways has been awarded to Performance Systems Development. This will allow for better synergies in outreach to both contractors and customers.

3.2.4 Nonresidential Prescriptive Program Results

Table 18. PROGRAM COSTS			
Component (Nominal $)	**FY2025 - Actual**	**FY2025 - Budget**	**%**
Direct Utility Costs	**$170,744**	**$995,700**	**17%**
Customer Incentives	$156,453	$853,700	18%
Administration	$12,653	$77,000	16%
Marketing	$1,247	$54,000	2%
Inspections	$390	$11,000	4%
Evaluations	$0	$0	0%
Incremental Participant Costs	**$114,108**	**$1,295,514**	**9%**

Table 19. PROGRAM SAVINGS			
Type	**FY2025 - Actual**	**FY2025 - Projected**	**%**
Natural Gas (MMBtus)			
Annual	5,354	57,209	9%
Lifetime	91,925	1,237,197	7%
Electric Energy (MWh)			
Annual	2.3	54.5	4%
Lifetime	27.1	700.7	4%
Capacity Savings (MW)	0.000	0.007	4%
Water Savings (Gallons)			
Annual	453,144	3,413,079	13%
Lifetime	6,617,740	50,523,665	13%

3.3.2.1 Marketing Activity

In 2025, marketing was conducted through established builders and HERS raters who have been participants in the programs mandated for large EDCs by Act 129 of 2008, P.L. 1592 (Act 129). Also, emails and/or newsletters with program updates were periodically distributed to all participating builders and raters that participated in the program.

3.3.2.2 Inspection and Evaluation Activity

There were a total of 68 HERS ratings reviewed by PSD. All reviewed ratings passed inspection.

3.3.3 Program Updates for FY2024

There are no program updates to report at this time.

3.3.4 Residential New Construction Program Results

Table 23. PROGRAM COSTS			
Component (Nominal $)	**FY2025 - Actual**	**FY2025 - Budget**	**%**
Direct Utility Costs	**$1,851,518**	**$2,083,700**	**89%**
Customer Incentives	$1,143,253	$1,356,700	84%
Administration	$663,324	$631,000	105%
Marketing	$916	$50,000	2%
Inspections	$44,025	$46,000	96%
Evaluations	$0	$0	0%
Incremental Participant Costs	**$2,332,433**	**$1,194,371**	**195%**

3.4.3 Program Updates for FY2025

There are no program updates to report at this time.

3.4.4 Residential Retrofit Program Results

Table 30. PROGRAM COSTS			
Component (Nominal $)	**FY2025 - Actual**	**FY2025 - Budget**	**%**
Direct Utility Costs	**$481,836**	**$604,000**	**80%**
Customer Incentives	$191,117	$143,000	134%
Administration	$238,628	$380,000	63%
Marketing	$44,768	$67,000	67%
Inspections	$7,323	$14,000	52%
Evaluations	$0	$0	0%
Incremental Participant Costs	**$367,776**	**$162,714**	**226%**

3.5.2.2 Inspection and Evaluation Activity

In FY2025, 28 of the 45 completed projects were inspected by PSD, and all of them passed prior to being paid incentives.

The program spent $0 for evaluation activity against an original budget of $0.

3.5.3 Program Updates for FY2025

There are no program updates to report at this time.

3.5.4 Nonresidential Custom Program Results

Table 34. PROGRAM COSTS			
Component (Nominal $)	**FY2025 - Actual**	**FY2025 - Budget**	**%**
Direct Utility Costs	**$1,863,588**	**$1,872,800**	**100%**
Customer Incentives	$1,427,400	$1,377,800	104%
Administration	$416,735	$406,000	103%
Marketing	$1,025	$57,000	2%
Inspections	$18,428	$32,000	58%
Evaluations	$0	$0	0%
Incremental Participant Costs	**$3,100,229**	**$2,970,459**	**104%**

Table 35. PROGRAM SAVINGS			
Type	**FY2025 - Actual**	**FY2025 - Projected**	**%**
Natural Gas (MMBtus)			
Annual	89,430	43,406	206%
Lifetime	1,734,424	868,126	200%
Electric Energy (MWh)			
Annual	210.5	45.5	462%
Lifetime	3,752.8	910.5	412%
Capacity Savings (MW)	0.096	0.052	185%
Water Savings (Gallons)			
Annual	0	0	100%
Lifetime	0	0	100%

3.6.4 Combined Heat and Power Program Results

Table 38. PROGRAM COSTS			
Component (Nominal $)	**FY2025 - Actual**	**FY2025 - Budget**	**%**
Direct Utility Costs	**$12,543**	**$902,500**	**1%**
Customer Incentives	$0	$750,000	0%
Administration	$12,543	$60,000	12%
Marketing	$0	$40,000	0%
Inspections	$0	$7,500	0%
Evaluations	$0	$45,000	0%
Incremental Participant Costs	**$0**	**$16,980,989**	**0%**

Table 39. CHP PROGRAM SAVINGS				
	FY2025		**Phase**	
Equipment	**Annual**	**Lifetime**	**Annual**	**Lifetime**
Net Primary Fuel Savings (MMBtus)	0	0	140,246	2,804,915

Table 40. PROGRAM COST-EFFECTIVENESS (BASE CASE + DRIPE & CO2) PV Year (2018)		
Benefits/Cost Component	**FY2025**	**Phase**
TRC NPV Benefits	$0	$18,431,443
TRC NPV Costs	$7,662	$3,999,139
TRC Net Benefits	(7,662)	14,432,305
TRC Benefit/Cost Ratio	**0.00**	**4.61**

Table 41. PROGRAM COST-EFFECTIVENESS (BASE CASE) PV Year (2018)		
Benefits/Cost Component	**FY2025**	**Phase**
TRC NPV Benefits	$0	$7,350,146
TRC NPV Costs	$7,662	$3,999,139
TRC Net Benefits	(7,662)	3,351,007
TRC Benefit/Cost Ratio	**0.00**	**1.84**

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-35

Request:

Reference UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-19, UGI Utilities, Inc. – Gas Division Energy Efficiency and Conservation Plan Phase I Program Year 5 (FY 2024), and UGI Utilities, Inc. – Gas Division Energy Efficiency and Conservation Plan Phase I Program Year 6 (FY 2025), concerning EE&C program costs. Provide the following:

A. A detailed breakdown of the adjusted budget of $12,026,000 with supporting documentation for the expense adjustment amount of $340,000 for the FPFTY.

B. The annual budgeted EE&C costs and actual EE&C costs incurred for FY2021, FY2022, FY2023, FY2024 – indicating the percentage of actual EE&C costs incurred above or below the budgeted EE&C costs for each year.

C. A detailed explanation for any difference in spending above or below 5% of budgeted costs for the amounts included in the response to Part C above.

D. The annual actual natural gas savings and projected natural gas savings for FY2020, FY2021, FY2022, FY2023, FY2024, the HTY, the FTY, and the FPFTY – indicating the percentage of actual natural gas savings above or below the projected natural gas savings for each year.

E. A detailed explanation for any difference in savings above or below 5% of projected natural gas savings for the amounts included in the response to Part E above.

F. The amount and percentage of annual customer participation for FY2020, FY2021, FY2022, FY2023, FY2024, and the HTY.

G. The projected amount and percentage of annual customer participation for the FTY and the FPFTY.

H. A detailed explanation of the actions the Company is taking to increase EE&C program spending efficiency, increased natural gas savings, and/or increased customer participation.

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RE-1 thru RE-41)
Delivered on March 19, 2026

I&E-RE-35 (Continued)

Response:

A. Please see Attachment I&E-RE-35-A.

B. Please see Attachment I&E-RE-35-B.

C. Please see Attachment I&E-RE-35-B.

D. Please see Attachment I&E-RE-35-C.

E. Please see Attachment I&E-RE-35-C.

F. Please see Attachment I&E-RE-35-D.

G. Please see Attachment I&E-RE-35-D.

H. In terms of spending efficiency, UGI Gas effectively utilizes its internal resources and contracted Conservation Service Providers to deliver meaningful energy efficiency and conservation programs. As demonstrated in the Company's Program Year 5 EE&C Annual Report, UGI Gas spent 82% of its total budget, but successfully achieved 95% of its natural gas savings goal. For Program Year 6, UGI Gas spent 80% of its total budget, but successfully achieved 85% of its natural gas savings goal.

Furthermore, in an effort to increase customer participation and natural gas savings, the Company continues to utilize marketing campaigns to promote the availability of its energy efficiency and conservation programs while also engaging with numerous HVAC companies to increase awareness of the various programs.

Prepared by or under the supervision of: Brian J. Meilinger

UGI Utilities, Inc. - Gas Division
UGI Gas Book V, Exhibit A- Fully Projected, Schedule D-19
Adjustment-Energy Efficiency and Conservation Programs
Supporting Documentation for the expense adjustment

Category		FY 2027 Budget	
Residential Prescriptive (RP)		$ 6,176,361	
Residential New Construction (RNC)		$ 2,005,868	
Residential Retrofit (RR)		$ 807,443	
NonResidential (NR)		$ 2,232,012	
Portfolio-wide Costs		$ 833,755	
CHP Program		$ 310,342	
Total	Sch D-19, Ln 1	$ 12,365,781	
Less: Adjustments	Sch D-19, Ln 4	(340,429)	(See adjustment detail below)
	Sch D-19, Ln 2	$ 12,025,352	

Line #	Expense Adjustment:	
1	$ (299,585)	Attachment I&E-RS-5-D(a),UGI Gas Exhibit SAE-4, USP Adj.Page, Line 12(Row 42), Column M, Total EE&C Revenue Adjustment
2	$ (1,160)	Attachment I&E-RS-5-D(a),UGI Gas Exhibit SAE-4,EE&C Adj. Page, Row 40, Column N
3	$ (39,685)	Attachment I&E-RS-5-D(a), UGI Gas Exhibit SAE-4,EE&C Conserv Impact Page, Line 12 (Row 56), Column J
4	$ (340,429)	L4=L1+L2+L3, Total Expense Adjustment, Line 3, shown on UGI Gas Book V, Exhibit A, Fully Projected, Schedule D-19

Note: Attachment I&E-RS-5-D(a) contains UGI Gas Exhibit SAE-4(a)-(m) in excel format.

UGI Utilities, Inc. - Gas Division
Energy Efficiency & Conservation Program Natural Gas Savings
For the 12-Months Ended September 30, 2020, 2021, 2022, 2023, 2024, 2025, 2026, and 2027
(Savings in MMBtu)

Year	Actual Program Savings	Budget Program Savings	Variance	%	Explanation for savings above or below 5% of projected natural gas savings
2020	182,579	204,703	(22,124)	-10.8%	Lower Residential Retrofit and Nonresidential Prescriptive savings to budget partially offset by higher Residential Prescriptive and Residential New Construction savings
2021	225,831	233,604	(7,773)	-3.3%	
2022	281,068	271,510	9,558	3.5%	
2023	261,143	284,865	(23,722)	-8.3%	Lower Nonresidential Prescriptive and Residetial Prescriptive savings to budget partially offset by higher Nonresidential Custom savings
2024	271,408	284,865	(13,457)	-4.7%	
2025	241,249	284,865	(43,616)	-15.3%	Lower Nonresidential Prescriptive and Residetial Prescriptive savings to budget partially offset by higher Nonresidential Custom savings
2026	-	269,502			
2027	-	290,017			

Attachment I&E-RE-35B

I&E Modified

	Program	2021 Actual Program Costs	2021 Budget	Variance	%
1	Residential Prescriptive (RP)	$ 5,452,236.37	$ 5,674,931.66	$ (222,695.29)	-3.9%
2	Residential New Construction (RNC)	$ 1,190,613.30	$ 2,110,862.51	$ (920,249.21)	-43.6%
3	Residential Retrofit (RR)	$ 400,850.34	$ 515,055.75	$ (114,205.41)	-22.2%
4	Nonresidential Prescriptive (NP)	$ 249,102.74	$ 556,383.74	$ (307,281.00)	-55.2%
5	Nonresidential Custom (NC)	$ 618,069.50	$ 676,907.86	$ (58,838.36)	-8.7%
6	Portfolio-wide Costs	$ 684,149.02	$ 690,380.39	$ (6,231.37)	-0.9%
7	CHP Program	$ 16,862.77	$ 262,367.75	$ (245,504.98)	-93.6%
8	**Total**	**$ 8,611,884.04**	**$ 10,486,889.66**	**$ (1,875,005.62)**	-17.9%
9	FY 2021 Cost Variance Percentage				82.1%

	Program	2022 Actual Program Costs	2022 Budget	Variance	%
10	Residential Prescriptive (RP)	$ 5,056,430.33	$ 6,472,135.00	$ (1,415,704.67)	-21.9%
11	Residential New Construction (RNC)	$ 2,288,213.67	$ 1,886,416.67	$ 401,797.00	21.3%
12	Residential Retrofit (RR)	$ 497,954.35	$ 558,333.33	$ (60,378.98)	-10.8%
13	Nonresidential Prescriptive (NP)	$ 320,374.40	$ 394,205.00	$ (73,830.60)	-18.7%
14	Nonresidential Custom (NC)	$ 1,445,263.15	$ 1,224,166.67	$ 221,096.48	18.1%
15	Portfolio-wide Costs	$ 777,546.52	$ 724,108.29	$ 53,438.23	7.4%
16	CHP Program	$ 278,912.94	$ 546,666.67	$ (267,753.73)	-49.0%
17	**Total**	**$ 10,664,695.36**	**$ 11,806,031.63**	**$ (1,141,336.27)**	-9.7%
18	FY 2022 Cost Variance Percentage				90.3%

	Program	2023 Actual Program Costs	2023 Budget	Variance	%
19	Residential Prescriptive (RP)	$ 6,501,562.52	$ 5,808,120.25	$ 693,442.27	11.9%
20	Residential New Construction (RNC)	$ 1,932,927.65	$ 2,133,700.00	$ (200,772.35)	-9.4%
21	Residential Retrofit (RR)	$ 416,222.58	$ 512,800.00	$ (96,577.42)	-18.8%
22	Nonresidential Prescriptive (NP)	$ 289,337.43	$ 467,900.17	$ (178,562.74)	-38.2%
23	Nonresidential Custom (NC)	$ 1,604,903.91	$ 1,810,500.00	$ (205,596.09)	-11.4%
24	Portfolio-wide Costs	$ 643,834.34	$ 803,221.34	$ (159,387.00)	-19.8%
25	CHP Program	$ 16,655.00	$ 229,166.67	$ (212,511.67)	-92.7%
26	**Total**	**$ 11,405,443.43**	**$ 11,765,408.42**	**$ (359,964.99)**	-3.1%
27	FY 2023 Cost Variance Percentage				96.9%

	Program	2024 Actual Program Costs	2024 Budget	Variance	%
28	Residential Prescriptive (RP)	$ 5,847,395.04	$ 6,244,373.65	$ (396,978.61)	-6.4%
29	Residential New Construction (RNC)	$ 1,557,926.44	$ 1,920,058.33	$ (362,131.89)	-18.9%
30	Residential Retrofit (RR)	$ 471,475.94	$ 512,393.33	$ (40,917.39)	-8.0%
31	Nonresidential Prescriptive (NP)	$ 363,314.42	$ 380,903.87	$ (17,589.45)	-4.6%
32	Nonresidential Custom (NC)	$ 1,771,711.51	$ 1,645,700.00	$ 126,011.51	7.7%
33	Portfolio-wide Costs	$ 755,709.85	$ 742,598.64	$ 13,111.21	1.8%
34	CHP Program	$ 7,430.00	$ 379,166.67	$ (371,736.67)	-98.0%
35	**Total**	**$ 10,774,963.20**	**$ 11,825,194.49**	**$ (1,050,231.29)**	-8.9%
36	FY 2024 Cost Variance Percentage				91.1%

I&E Modified

	Program	2025 Actual Program Costs (1)	2025 Budget	Variance	%
37	Residential Prescriptive (RP)	$ 5,191,708.00	$ 6,494,900.00	$ (1,303,192.00)	-20.1%
38	Residential New Construction (RNC)	$ 1,851,518.00	$ 2,083,700.00	$ (232,182.00)	-11.1%
39	Residential Retrofit (RR)	$ 481,836.00	$ 604,000.00	$ (122,164.00)	-20.2%
40	Nonresidential Prescriptive (NP)	$ 170,744.00	$ 995,700.00	$ (824,956.00)	-82.9%
41	Nonresidential Custom (NC)	$ 1,863,588.00	$ 1,872,800.00	$ (9,212.00)	-0.5%
42	Portfolio-wide Costs (2)	$ 815,441.00	$ 950,000.00	$ (134,559.00)	-14.2%
43	CHP Program	$ 12,543.00	$ 902,500.00	$ (889,957.00)	-98.6%
44	**Total**	**$ 10,387,378.00**	**$ 13,903,600.00**	**$ (3,516,222.00)**	-25.3%
45	FY 2025 Cost Variance Percentage				74.7%

46	Historical Three-Year Average Cost Variance Percentage [(Line 27 + Line 36 + Line 45) ÷ 3]	87.6%

(1) EE&C Plan Year 6, p. 4

(2) Line 42 FY 2025 Budgeted Portfolio-wide Costs calculated as the difference between all other programs' budget and the total EE&C Plan budget

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule C-4
Witness: A. M. Keller
Page 1 of 9

I&E Modified

Working Capital

Line No	Description	[1] Fully Projected TYE 9-30-27	[2] Reference
1	Working Capital for O & M Expense	$ 56,179	C-4, Page 2
2	Interest Payments	(9,459)	C-4, Page 7
3	Tax Payment Lag Calculations	4,570	C-4, Page 8
4	Prepaid Expenses	14,400	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 65,691	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule C-4
Witness: A. M. Keller
Page 2 of 9

Summary of Working Capital

Line #	Description	Reference	[1] Test Year Expenses	[2] Factor	[3] I&E Modified Number of (Lead) / Lag Days [2] * [3]	[4] Totals
WORKING CAPITAL REQUIREMENT						
1	REVENUE LAG DAYS	Page 3				57.46
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 81,369	12.00	$ 976,422	
4	Purchased Gas Costs	Sch D-6	404,972	26.09	10,563,938	
5	Other Expenses	L 18 - L 3 to L 4	196,215	36.55	7,171,648	
6	Total	Sum (L 3 to L 5)	$ 682,555		$ 18,712,009	
7	O & M Expense Lag Days	L6, C 4 / C 2				27.41
8	Net (Lead) Lag Days	L 1 - L 7				30.04
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,870
10	Working Capital for O & M Expense	L 8 * L 9				$ 56,179
11	Interest Payments	Page 7				(9,459)
12	Tax Payment Lag Calculations	Page 8				4,570
13	Prepaid Expenses	Page 9				14,400
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 65,691
15	Pro Forma O & M Expense		$ 702,897			
	Less:					
16	Uncollectible Expense		20,342			
17	Sub-Total		20,342			
18	Pro Forma Cash O&M Expense		$ 682,555			

I&E Statement No. 2
Witness: Drew Breuning

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Direct Testimony

of

Drew Breuning

Bureau of Investigation and Enforcement

Concerning:

Rate of Return

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Drew Breuning. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. SUMMARIZE YOUR EDUCATION AND EMPLOYMENT HISTORY.

A. An outline of my education and employment history is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) and make recommendations regarding the Company's rate of return, including capital structure, cost of long-term debt, the cost of equity, and the overall fair rate of return for the fully projected future test year (FPFTY) ending September 30, 2027.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A BASE RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income. It is typically expressed as a percentage of the amount of an asset base at a particular point in time, which in base rate proceedings, is the projected rate base balance at the end of the test year.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

$$RR = E + D + T + (RB \times ROR)$$

Where:

RR	=	Revenue Requirement
E	=	Operating Expenses
D	=	Depreciation Expense
T	=	Taxes
RB	=	Rate Base
ROR	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an *opportunity* to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect. The Commission has the authority to determine the fair revenue

requirement and rate of return, which the utility has the opportunity to earn, but is not guaranteed to earn.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *Federal Power Commission et al v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.
4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by

comparing the percentage of each capitalization component, which has financed rate base, to total capital. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure. Because of this difficulty, a proxy group is used as discussed later in this testimony. Next, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The I&E table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS?

A. Dylan W. D'Ascendis, Partner at ScottMadden, Inc., is the primary witness addressing rate of return and cost of common equity for UGI Gas (UGI Gas Statement No. 8).

Q. PLEASE SUMMARIZE THE COMPANY'S RATE OF RETURN CLAIMS.

A. Mr. D'Ascendis recommends the following rate of return for the Company based on the FPFTY ending September 30, 2027:[1]

Company Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
UGI Utilities, Inc. - Gas Division			
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	10.75%	5.83%
Total	100.00%		8.20%

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION.

A. I recommend the following rate of return for the Company:[2]

[1] UGI Gas Exhibit B, Schedule DWD-1, p. 1.
[2] I&E Exhibit No. 2, Schedule 1.

I&E Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	9.81%	5.32%
Total	100.00%		7.69%

Q. HOW HAVE YOU CALCULATED YOUR RECOMMENDED RETURN ON EQUITY?

A. My recommended return on equity of 9.81% is based on the average of the following results:

DCF Result	10.47%
Average of I&E Calculated CAPM Result and Kroll CAPM Result	9.25%
National Average of Natural Gas Distribution Authorized ROEs from S&P Global	9.70%
Average*	**9.81%**

*(10.47% + 9.25% + 9.70%) / 3 = 9.81%

As explained in further detail below, my return on equity recommendation is calculated using the DCF method, the average of two variations of the CAPM method, and the recent national average authorized return on equity for rate cases involving natural gas distribution utilities.

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits in comparison to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR UTILITY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are representative of the Company. I applied the following criteria to Value Line's "Natural Gas Utility" company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated gas utility industry.
2. The company's stock must be publicly traded.
3. Investment information for the company must be available from more than one source, which includes Value Line.
4. The company must not be currently involved in an announced merger or the target of an acquisition.
5. The company must have four consecutive years of historic earnings data.
6. The company must be operating in a state that has a deregulated natural gas utility market.

Q. WHAT CRITERIA DID MR. D'ASCENDIS USE IN SELECTING HIS PROXY GROUP COMPANIES?

A. Mr. D'Ascendis determined his proxy group of companies by using the following criteria:[3]

[3] UGI Gas Statement No. 8, p. 13, lines 6-23.

1. The company is included in *Value Line*'s Natural Gas Utility Group.
2. The company must have at least 60% of fiscal year 2024 total operating income and at least 60% of fiscal year 2024 total assets attributable to regulated gas distribution operations.
3. The company must not be currently involved in any major merger or acquisition activity.
4. The company must not have cut or omitted their common dividends during the five years ended 2024.
5. The company must have beta coefficients available from *Value Line* and Bloomberg Professional Services.
6. The company must have positive *Value Line* five-year dividends per share growth rate projections.
7 The company must have *Value Line*, Zacks, or S&P Capital IQ consensus five-year earnings per share growth rate projections.

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I include the following six companies in my proxy group:[4]

[4] I&E Exhibit No. 2, Schedule 2.

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

Q. WHAT PROXY GROUP DID MR. D'ASCENDIS USE IN HIS ANALYSIS?

A. Mr. D'Ascendis includes the following seven companies in his proxy group:[5]

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

Q. DO YOU AGREE WITH MR. D'ASCENDIS' PROXY GROUP?

A. Not entirely. While we do have six companies that match, Mr. D'Ascendis includes one company that I do not.

[5] UGI Gas Statement No. 8, p. 14, line 1.

Q. MR. D'ASCENDIS HAS INCLUDED SOUTHWEST GAS HOLDINGS, INC. (SWX) IN HIS PROXY GROUP AND YOU DID NOT. PLEASE EXPLAIN.

A. I have excluded SWX from my proxy group, as this company did not meet my first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry. SWX generates 48.42% percent of its revenue from its regulated gas utility. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than fifty percent of revenues come from the regulated gas sector, the company is not comparable to the subject utility and does not provide a similar level of regulated business. Therefore, I did not include Southwest Gas Holdings, Inc. in my proxy group.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary funding sources are long-term debt and common equity. A capital structure may also include preferred stock and/or short-term debt, which is not the case for the Company.

Q. WHAT IS THE CLAIMED CAPITAL STRUCTURE USED BY THE COMPANY?

A. The Company is proposing a forecasted capital structure which is summarized in the table below:[6]

Type of Capital	Ratio
Long-Term Debt	45.75%
Common Equity	54.25%
Total	**100.00%**

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. D'Ascendis explains that the requested capital structure is based on the Company's recent actual capital structure.[7] Further, he claims the common equity ratio requested by the Company is appropriate and consistent with the range of common equity ratios maintained by the operating utility subsidiaries of his proxy group.[8]

6 UGI Gas Statement No. 8, p. 14, lines 4-5.
7 UGI Gas Statement No. 8, p. 3, lines 7-8.
8 UGI Gas Statement No. 8, p. 15, ln. 11 through p. 16, ln. 12.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. Although I believe a capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility as well as trying to control costs to ratepayers, in this proceeding, I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2024 (most recently available) capital structures. The most recent five-year average range contains individual company capital structure ratios from 39.53% to 58.23% long-term debt and 36.62% to 60.47% equity, with an overall five-year average of 50.40% long-term debt and 48.70% common equity.[9]

It is worth noting that the Company's equity ratio is well above the average of the proxy group's equity ratios. This equity-heavy capital structure must be recognized when considering UGI Gas' financial risk, as higher equity ratios generally correspond with lower financial risk.

[9] I&E Exhibit No. 2, Schedule 3.

Q. HAS THE COMMISSION COMMENTED ON UGI GAS' CURRENT CAPITAL STRUCTURE?

A. Yes. Commissioner Barrow expressed particular concern regarding the financial impact on customers in relation to equity heavy capital structures. She states, "… I urge the parties to take a critical look at the Company's requested rate of return and return on equity (ROE) as well as the capital structure (common equity ratio and debt capital) to ensure reasonableness. Deviations in each of these items translate into millions of dollars charged to customers of all rate classes."[10]

Additionally, Commissioner Barrow previously commented on Columbia Gas' requested capital structure of 54.4% equity and 45.6% debt. The Office of Consumer Advocate and the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania argued in favor of a hypothetical 50/50 capital structure, citing their proxy group's average capital structure was 45% equity and 55% debt. Commissioner Barrow stated that the discrepancy between the proxy group and Columbia Gas' capital structure makes it necessary for an adjustment to the Company's capital structure, and that a 50/50 capital structure "is a better representation of the Company's **actual** financial risk and would have resulted in millions of dollars in reduced revenue requirement for the Company and resultant lower rates for Columbia Gas' customers."[11]

[10] I&E Exhibit No. 2, Schedule 4.
[11] I&E Exhibit No. 2, Schedule 5.

Q. WHAT IS THE RECENT NATIONAL AVERAGE AUTHORIZED CAPITAL STRUCTURE FOR GAS DISTRIBUTION UTILITIES ACROSS THE U.S.?

A. According to data gathered from S&P Global Market Intelligence, the average authorized equity ratio for natural gas distribution cases in the United States from January 2025 to March 2026 was 51.62%.[12]

Q. HAVE YOU CONSIDERED WHAT CAPITAL STRUCTURES ARE PROJECTED TO BE FOR THE NATURAL GAS UTILITY INDUSTRY IN THE NEAR FUTURE?

A. Yes. According to Value Line's 2027 estimates, the projected capital structures for my proxy group are as follows:

Value Line 2027 Capital Structure Projections

		Long-Term Debt Ratio	Common Equity Ratio
Atmos Energy Corporation	ATO	40.00%	60.00%
Chesapeake Utilities Corp.	CPK	48.50%	51.50%
New Jersey Resources Corporation	NJR	55.50%	44.50%
NiSource Inc.	NI	55.00%	45.00%
Northwest Natural Holding Company	NWN	55.00%	45.00%
ONE Gas, Inc.	OGS	44.00%	56.00%
Average		49.67%	50.33%

[12] I&E Exhibit No. 2, Schedule 6.

These future projections are consistent with the proxy group's historical five-year average capital structure of 48.70% equity and 50.40% debt.

UGI Gas' claimed capital structure of 54.25% equity and 45.75% debt is considerably more equity-heavy than the proxy group's five-year averages, Value Line's 2027 projections, and the recent national authorized capital structures for natural gas distribution utilities. This equity-heavy capital structure must be recognized when considering UGI Gas' financial risk, as higher equity ratios generally correspond with lower financial risk as Mr. D'Ascendis himself concedes. He agrees that all other things being equal, a company with a higher equity ratio faces less financial risk than a company with a lower equity ratio.[13]

For consideration when examining the Company's overall financial risk, the table below illustrates the cost savings to ratepayers if the Company were to employ an optimal 50% long-term debt and 50% common equity capital structure in its cost of capital while maintaining its claimed return on equity and rate base:

[13] I&E Exhibit No. 2, Schedule 7.

UGI Utilities, Inc. - Gas Division			
Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
AS FILED CAPITAL STRUCTURE			
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	10.75%	5.83%
Total	100.00%		8.20%
50/50 OPTIMAL CAPITAL STRUCTURE			
Long-Term Debt	50.00%	5.17%	2.59%
Common Equity	50.00%	10.75%	5.38%
Total	100.00%		7.97%
Difference In The Overall Rate of Return (8.20% - 7.97% = 0.23%)			0.23%
Impact Prior to Gross Up (Claimed Rate Base* x Difference In The Overall Rate of Return) ($4,319,352,000 x .0023)			$9,934,510
Gross Revenue Conversion Factor**			1.392298
Total Impact To Ratepayers ($9,934,510 x 1.392298)			**$13,831,798**
*UGI Exhibit A, Schedule A-1, Line 9. **UGI Exhibit A, Schedule A-1, Line 24.			

In this example, if the Company were to employ a 50/50 capital structure and no change to the cost of debt or requested return on equity, the cost savings to ratepayers would be $13,831,798. While I understand that achieving and maintaining an exact 50/50 capital structure is not always feasible, this example is intended to demonstrate UGI Gas' financial security as compared to its peers.

Also, it is worth noting that UGI Gas' actual capital structure has been trending toward an optimal 50/50 since 2023.[14]

COST OF LONG-TERM DEBT

Q. WHAT IS THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Company's claimed long-term debt cost rate is 5.17% for the FPFTY.[15]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF LONG-TERM DEBT?

A. I recommend using the Company's claimed long-term debt cost rate of 5.17% for the FPFTY.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S COST RATES OF LONG-TERM DEBT?

A. I accept UGI Gas' claimed debt cost because it falls within my proxy group's implied long-term debt cost range of 2.54% to 6.49%, with an average implied long-term debt cost of 4.69% for 2024.[16] The Company's cost rate of long-term debt is also below the Mergent Bond Record average yield of 5.76% for the period

[14] I&E Exhibit No. 2, Schedule 8.
[15] UGI Gas Statement No. 8, p. 3, lines 8-11.
[16] I&E Exhibit No. 2, Schedule 9.

of February 2025 through January 2026 for A-rated public utility bonds.[17] I recommend that the Company's claimed cost rate of long-term debt be used since it is reasonable and falls within the metrics described above.

COST OF COMMON EQUITY

Common Methods

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the Discounted Cash Flow (DCF) Method, the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the traditional economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows. The DCF method is also considered a forward-looking model to estimate the cost of common equity.

[17] I&E Exhibit No. 2, Schedule 10.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship between a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it also directly measures the systematic risk of a company group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of opportunity cost. This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. Similar to the RP method, the CE method does not measure the specific risk of a company. The most problematic issue with the CE method is determining what constitutes comparable companies.

Q. WHAT METHODS DO YOU RECOMMEND USING TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR THE COMPANY?

A. I recommend using a combination of methods to determine the appropriate cost of common equity. I have employed the DCF, two versions of the CAPM, and have incorporated the recent average national authorized return on equity for gas distribution companies. I have used the DCF and CAPM because they have the most wide-spread regulatory acceptance, and the Commission has more recently based its ROE decisions on a combination of the DCF and CAPM methods. Additionally, the average authorized returns for gas distribution utilities from across the nation in rate case decisions should be considered, as it aligns with the guidance derived from the *Hope* and *Bluefield* cases that the subject utility is entitled to a return similar to that being earned by comparable enterprises.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF IN YOUR ANALYSIS TO HELP DETERMINE YOUR RECOMMENDED RETURN ON EQUITY.

A. I have used the DCF for a variety of reasons. First, the DCF is appealing to investors as it is based upon the concept that the receipt of dividends in addition to the expected appreciation is the total return requirement determined by the market.[18] Second, the use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. Third, the use of the utility's own, or in this case, the proxy group's stock prices and growth rates directly in the calculation make the DCF industry and company specific. Finally, current inflationary and economic trends are most certainly reflected in a stock's price, which is used in determining the dividend yield, and by analysts who generate forecasted earnings growth rates. Therefore, the DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for the current economic market because it measures the cost of equity directly.

[18] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, p. 153.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE CAPM IN YOUR ANALYSIS TO HELP DETERMINE YOUR RECOMMENDED RETURN ON EQUITY.

A. I have included a CAPM analysis in my recommendation as it has been the Commission's recent desire to employ more than one ROE methodology. I chose to use both the CAPM and the DCF because they include inputs that allow the results to be specific to the utility industry. The CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have also included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, can affect the outcome of each method in different ways. Although I have provided an analysis and included the results of the CAPM in my recommendation, it does have several disadvantages that should be considered.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given the recent events that have impacted economic conditions. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM, and similarly the RP method, are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Additionally, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock

Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[19] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory, a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications."[20]

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults explained above. The RP method has a number of underlying assumptions and the most critical one, as well as the most disputed

[19] Berg, Eric N., "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," *The New York Times*, February 18, 1992, *nytimes.com*, March 23, 2016.

[20] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

one, is the assumption that the equity risk premium is constant over the time.[21] More importantly, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

SUMMARY OF THE COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSIS?

A. Mr. D'Ascendis used the DCF, CAPM, and the RP methods in analyzing the Company's cost of equity. Additionally, Mr. D'Ascendis used the Predictive Risk Premium Model (PRPM) and the Empirical Capital Asset Pricing Model (ECAPM) in forming his recommendations under the RP and the CAPM methods, respectively. Mr. D'Ascendis applied these methods to both his proxy group of regulated gas utilities and his non-price regulated proxy group. He then listed the

[21] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, pp. 167-168.

results for each method for the regulated utility group[22] and created a range based on the average of the median and mean of the methods' results for the non-price regulated group.[23] Further, Mr. D'Ascendis recommended that the cost of equity be increased by 5 basis points for what he labels a "business risk adjustment" due to the Company's small size. He also recommended that the cost of equity be increased by 12 basis points due to the Company incurring flotation costs when issuing common stock. Ultimately, Mr. D'Ascendis opined that a cost of equity of 10.75% is warranted.[24]

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR THE COMPANY?

A. Based upon my analysis, I recommend a cost of common equity of 9.81%.[25]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. As thoroughly explained above and discussed in further detail below, my recommendation is based on the use of the DCF, two versions of the CAPM, and the recent average national authorized return on equity for gas distribution companies.

[22] UGI Gas Statement No. 8, p. 4, line 12.
[23] UGI Gas Exhibit B, Schedule DWD-8, p. 1.
[24] UGI Gas Statement No. 8, p. 3, lines 7-8.
[25] I&E Exhibit No. 2, Schedule 1.

Discounted Cash Flow

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group were available from Value Line, no dividends were adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent

spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group:[26]

Proxy Group Dividend Yields	
Spot	3.07%
52-week Average	3.37%
Average	**3.22%**

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year earnings per share projected growth rate estimates from S&P, Zacks, and Value Line.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for my proxy group ranged from 5.75% to 8.08% with an overall average of 7.25%.[27]

[26] I&E Exhibit No. 2, Schedule 11.
[27] I&E Exhibit No. 2, Schedule 12.

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows:[28]

K	=	D_1/P_0	+	g
10.47%	=	3.22%	+	7.25%

Capital Asset Pricing Model

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock market
β	=	Beta measures the systematic risk of an asset
$R_m - R_f$	=	Equity Risk Premium (ERP)

[28] I&E Exhibit No. 2, Schedule 13.

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the overall stock market.

Q. HOW DID YOU DETERMINE BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.78.[29]

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR CAPM ANALYSIS?

A. I used the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct

[29] I&E Exhibit No. 2, Schedule 14.

parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I used the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives. Additionally, the Commission has historically agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[30]

The forecasted yield on the 10-year Treasury Note, as seen in Blue Chip Financial Forecasts, remains steady at 4.20% from the second quarter of 2026 to the second quarter of 2027, and it is forecasted to remain at 4.20% from 2027-2031. For my CAPM analysis, I used 4.20%, which is the average of all the yield forecasts I observed.[31]

[30] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99; *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, p. 154 (Order Entered May 16, 2022); *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258 (Order Entered January 18, 2024). *See generally* Disposition of Cost of Common Equity, pp. 107-108; *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 & R-2023-3043190 (Order Entered July 22, 2024). *See generally* Disposition of Capital Asset Pricing Model (CAPM), pp. 171-172.

[31] I&E Exhibit No. 2, Schedule 15.

Q. HOW DID YOU DETERMINE THE RETURN ON THE OVERALL STOCK MARKET IN YOUR CAPM ANALYSIS?

A. To arrive at a representative expected return on the overall stock market, I observed Value Line's 1700 stocks and the historical returns of the S&P 500. Value Line expects its universe of approximately 1700 stocks to have an average yearly return of 10.78% over the next three to five years based on a forecasted dividend yield of 2.00% and a yearly index appreciation of 40%. The S&P 500 Index has had an average return of 12.35% over the past 100 years (1926-2025).[32] I have averaged these two figures, which results in an estimated market return of 11.57%.[33]

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CALCULATED CAPM ANALYSIS?

A. The result of my analysis is as follows:[34]

K	=	R_f	+	$\beta(R_m - R_f)$
9.95%	=	4.20%	+	0.78(11.57% - 4.20%)

[32] I&E Exhibit No. 2, Schedule 16.
[33] I&E Exhibit No. 2, Schedule 17.
[34] I&E Exhibit No. 2, Schedule 18.

Q. HAVE YOU PROVIDED AN ADDITIONAL CAPM ANALYSIS?

A. Yes. I have provided an additional CAPM analysis using Kroll's (formerly Duff & Phelps) recommended U.S. Equity Risk Premium (ERP) paired with Kroll's suggested use of the 20-year U.S. Treasury yield. Kroll is a trusted and publicly available source that bases their recommended ERP on current and forecasted economic and financial market conditions.

Q. WHAT IS KROLL'S CURRENT RECOMMENDED ERP?

A. As of January 30, 2026, Kroll recommends an ERP of 5.00%.[35]

Q. WHAT IS THE CURRENT 20-YEAR U.S. TREASURY YIELD?

A. As of February 25, 2026, the 20-Year U.S. Treasury yield was 4.65%.[36]

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS USING KROLL'S RECOMMENDED ERP AND THE SUGGESTED 20-YEAR U.S. TREASURY YIELD?

A. The result of my analysis is as follows:[37]

K	=	R_f	+	β(ERP)
8.55%	=	4.65%	+	0.78 (5.00%)

[35] I&E Exhibit No. 2, Schedule 19.
[36] I&E Exhibit No. 2, Schedule 20.
[37] I&E Exhibit No. 2, Schedule 18.

Q. WHAT IS THE RESULT OF YOUR CAPM ANALYSIS BASED ON THE AVERAGE OF YOUR CALCULATIONS AND USING KROLL'S RECOMMENDED ERP AND SUGGESTED 20-YEAR TREASURY YIELD?

A. The average of my CAPM analyses is 9.25% ((9.95% + 8.55%) ÷ 2).

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. As discussed earlier in my testimony, and as I&E has historically reasoned, the CAPM inputs are highly subjective, and other than beta, not company or industry specific. So, while I believe the DCF is the most reliable of the cost of equity models, I have provided a CAPM analysis as it does provide some value and it has been recent Commission precedent to rely on a combination of both the DCF and CAPM models.

National Average Authorized ROE

Q. WHAT IS THE RECENT NATIONAL AVERAGE AUTHORIZED ROE FOR GAS DISTRIBUTION UTILITIES ACROSS THE U.S.?

A. Data provided by S&P Global Market Intelligence shows the national average authorized ROE for gas distribution companies across the U.S. was 9.70% for cases decided in 2025 through March 11, 2026.[38]

[38] I&E Exhibit No. 2, Schedule 6.

Q. PLEASE EXPLAIN WHY YOU HAVE INCORPORATED RECENT NATIONAL AUTHORIZED EQUITY RETURNS FOR GAS UTILITIES INTO YOUR ROE ANALYSIS.

A. This information complies with the principle derived from the *Hope* and *Bluefield* cases, previously discussed in this testimony, that a utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures. Therefore, it is reasonable and logical to include in my recommendation the authorized returns of the Company's peers in recently completed rate cases across the country.

I&E Exhibit No. 2, Schedule 6, cited above, also illustrates the differences in the requested ROE and equity ratio as compared to gas distribution utilities in rate proceedings across the U.S. My recommended ROE of 9.81% for the Company in this case is comparable, yet higher than the national average of 9.70% for recently authorized returns.

CRITIQUE OF MR. D'ASCENDIS' PROPOSED COST OF EQUITY

Q. DO YOU AGREE WITH MR. D'ASCENDIS' 10.75% PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. D'Ascendis' proposed cost of equity analysis for several reasons. First, I disagree with the weights given to the results of his ECAPM and Risk Premium model, specifically the Predictive Risk Premium Model (PRPM)

analyses in his recommendation. Second, I disagree with his reliance on the 30-year Treasury Bond for his risk-free rate. Third, I disagree with the use of a proxy group of companies he used in his cost of equity calculation that are not regulated gas utilities. Finally, I disagree with his inclusion of a business risk adjustment and a flotation cost adjustment to his recommended cost of equity.

Mr. D'Ascendis' DCF Analysis

Q. PLEASE COMMENT ON MR. D'ASCENDIS' DCF ANALYSIS.

A. Mr. D'Ascendis presents a single-stage constant growth DCF analysis.[39] The result of his constant growth DCF when applied to his proxy group is a mean result of 10.35% and a median result of 10.71%. Mr. D'Ascendis ultimately presents a DCF result of 10.53%, the average of his mean and median results.[40]

Although our DCF methodologies vary slightly, Mr. D'Ascendis' average result of 10.53% is reasonable and almost identical to my DCF result of 10.47% on which I partially base my cost of equity recommendation. Since our DCF methodologies and results are so similar, I will not offer specific critiques of Mr. D'Ascendis' DCF analysis.

[39] UGI Gas Statement No. 8, p. 19, lines 10-11.
[40] UGI Gas Statement No. 8, p. 20, ln. 21 through p. 21, ln. 4.

Predictive Risk Premium Model

Q. WHAT IS THE PREDICTIVE RISK PREMIUM MODEL?

A. The PRPM is a method published in August 2011 by Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder in the article *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities.*[41] Mr. D'Ascendis' PRPM requires Eviews© statistical software to compute.[42]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' USE OF THE PRPM?

A. No. Mr. D'Ascendis' PRPM is not a commonly used method and cannot be evaluated or recreated without the software. I am also unaware of any state that has accepted the use of the PRPM. Additionally, the PRPM does not solve the problem of the RP method because it is still an indirect measure of the cost of equity, and the PRPM complicates the RP method with the introduction of a measurement that requires the use of specialized software.

[41] Ahern, Pauline M., Hanley, Frank J., Michelfelder, Richard A. (December 2011, Volume 40, Issue 3). *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities*. Journal of Regulatory Economics, pp. 261-278.

[42] UGI Gas Statement No. 8, p. 26, lines 16-17.

Empirical Capital Asset Pricing Model

Q. WHAT DOES MR. D'ASCENDIS CLAIM IS THE BASIS FOR HIS USE OF THE ECAPM?

A. Mr. D'Ascendis opines that the Security Market Line (SML) defined by the CAPM is not as steeply sloped as the predicted SML.[43] He uses a formula to account for the systematic risk that is not accounted for with beta in the CAPM formula. This methodology, called ECAPM, uses a factor, alpha, to account for the additional systematic risk not captured by beta.

Q. DO YOU AGREE WITH MR. D'ASCENDIS' USE OF THE ECAPM?

A. No. The use of the ECAPM in estimating the cost of capital does not increase the validity of the result, but instead it injects another measure of subjectivity to the CAPM in an attempt to make the Security Market Line more accurate. The ECAPM reduces the purpose of the beta, which is the only company-specific variable in the CAPM model. Additionally, I am not aware of any instances where a utility commission overseeing base rate proceedings explicitly relied on the ECAPM when determining an appropriate cost of equity for a regulated utility.

[43] UGI Gas Statement No. 8, p. 33, lines 13-17.

Risk-Free Rate

Q. WHAT RISK-FREE RATE DOES MR. D'ASCENDIS USE IN HIS CAPM ANALYSIS?

A. Mr. D'Ascendis used a risk-free rate of 4.53%, which he calculated by using the average of expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the first calendar quarter of 2027, and the long-term projections for the years 2027-2031 and 2032-2036.[44]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' USE OF THE 30-YEAR TREASURY BOND TO DETERMINE THE RISK-FREE RATE?

A. No. As discussed above, long-term Treasury Bonds have substantial maturity risk associated with the market risk and the risk of unexpected inflation and normally offer higher yields to compensate investors for these risks. Using the 10-year Treasury Note is more appropriate to balance the short-term volatility risk and the long-term inflation risk. Further, as noted above, the Commission has traditionally recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.

[44] UGI Gas Statement No. 8, p. 47, lines 13-17.

Domestic Non-Price Regulated Companies

Q. DOES MR. D'ASCENDIS RELY ON ANY MARKET DATA INPUTS SPECIFIC TO COMPANIES THAT ARE NOT REGULATED UTILITIES?

A. Yes. Mr. D'Ascendis asserted that in the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Consequently, he assembled a proxy group consisting of 32 non-price regulated firms which he asserts are comparable in terms of total risk to the Utility Proxy Group.[45] After forming his proxy group of 32 non-price regulated companies, Mr. D'Ascendis calculated common equity costs with data inputs specific to these companies using the DCF, RP, and CAPM methods.[46] The average of the mean and median results of these analyses yielded a range of 10.96% to 11.35% and was incorporated into Mr. D'Ascendis' final calculation of UGI Gas' return on equity claim of 10.75%.[47]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' APPROACH OF USING THE MARKET DATA OF NON-UTILITY COMPANIES TO CALCULATE UGI GAS' RETURN ON EQUITY?

A. No. The process of choosing a proxy group of non-utility companies similar in risk to UGI Gas is highly speculative and subjective. In effect, Mr. D'Ascendis blends the CE approach into the DCF, RP, and CAPM models. As stated earlier,

[45] UGI Gas Statement No. 8, p. 50, ln. 1 through p. 53, ln. 6.
[46] UGI Gas Exhibit B, Schedule DWD-8, p. 1.
[47] UGI Gas Exhibit B, Schedule DWD-1, p. 2.

the Commission has ruled on the use of the CE approach, specifically, the use of non-utility companies in comparable groups, and stated:

> The use of nonregulated companies as a comparable group for regulated firms requires numerous unsupportable assumptions which results in a highly speculative finding.[48]

Additionally, in the 2018 UGI Utilities, Inc. – Electric Division base rate case, the Commission made the following comments regarding the CE method, specifically, the use of non-utility companies in comparable groups, and stated:[49]

> With respect to the CE method, as noted above, this cost of equity method utilizes data for non-regulated firms. Thus, by its very nature, determining which companies are comparable is entirely subjective. In addition, the record indicates that the companies UGI utilized in its CE group results in the selection of companies such as Coca-Cola Company, Kellogg Company, and Walmart Stores, Inc. . . . Each of these companies operate in industries that are very different from a utility company and have significantly more competition, which would require a higher return for the associated additional risk.

If the non-price regulated company proxy group is truly similar in total risk to the Company, I would expect to see similar results in the calculation of the DCF, RP, and CAPM between the Utility and Non-Price Regulated Company proxy groups used by Mr. D'Ascendis. However, the Non-Price Regulated Company proxy group's DCF result of 11.29% is significantly higher than the Utility Proxy Group's DCF result of 10.53%. Additionally, the range of results calculated using cost of equity models with the Non-Price Regulated Company

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[48] *Pa. PUC v. Philadelphia Electric Co.*, 33 PUR 4th 319, 341 (Pa PUC 1980).

[49] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, p. 105 (Order entered October 25, 2018).

proxy group is 10.96% to 11.35%, which is skewed upward significantly compared to the Utility Proxy Group's range of 10.17% to 11.30%.[50] This clearly demonstrates the Commission's ruling cited above that the use of non-regulated companies as a comparable group for regulated firms results in a highly speculative finding.

Business Risk Adjustment

Q. WHAT BUSINESS RISK ADJUSTMENT HAS MR. D'ASCENDIS PROPOSED?

A. Mr. D'Ascendis added 5 basis points to his cost of common equity because he opined that smaller companies are less able to cope with significant events affecting sales, revenues, or earnings. He further stated that the loss of revenue from a few larger customers would have a greater effect on a small company. Mr. D'Ascendis relied upon technical literature including Kroll's Cost of Capital Navigator – U.S. Guide to Cost of Capital, "Size as a Predictor of Equity Returns," a Fama and French study entitled "The Capital Asset Pricing Model: Theory & Evidence," and Professor Eugene Brigham's textbook entitled "Fundamentals of Finance Management." Mr. D'Ascendis quantified his size adjustment based on size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2024

[50] UGI Gas Exhibit B, Schedule DWD-1, p. 2.

period. While Mr. D'Ascendis' proxy group companies fell in the 5th decile, he asserted that the Company fell in the 6th decile for size. He stated that while this indicates an upward equity risk premium adjustment of 26 basis points, he chose an upward adjustment of 5 basis points. Mr. D'Ascendis also attempts to discredit a study performed by Dr. Annie Wong, which I&E relies upon in rejection of his size adjustment, by citing a review of her study authored by Thomas M. Zepp. Additionally, Mr. D'Ascendis provides two studies he conducted that he claims illustrate the relationship between size and risk for utility companies. Finally, Mr. D'Ascendis points to a 2019 Commission Order where the Commission considered a size adjustment.[51]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' BUSINESS RISK ADJUSTMENT?

A. No. Mr. D'Ascendis' proposed business risk adjustment is unnecessary because the technical literature he cited supporting investment adjustments related to the size of a company is not specific to the utility industry; therefore, it has no relevance in this proceeding. In addition, any expense impact resulting from the lesser buying power of a smaller utility is reflected in the revenue requirement and the dollar-for-dollar recovery that applies to expenses. To apply an additional size

[51] UGI Gas Statement No. 8, pp. 54-61.

adjustment to a smaller regulated utility would only duplicate the burden to ratepayers.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE BUSINESS RISK ADJUSTMENT FOR SIZE IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes:

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[52]

UGI Gas has presented no significant evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. As will be further elaborated upon below, the criticism of Dr. Wong's study that Mr. D'Ascendis references does not contain enough credible evidence to refute Dr. Wong. Absent any credible article to refute Dr. Wong's findings, Mr. D'Ascendis' size adjustment to his cost of common equity results should be rejected.

[52] Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

Furthermore, the Commission has rejected the application of a size adjustment to the cost of equity calculation.[53]

Q. PLEASE COMMENT ON THE REVIEW OF DR. WONG'S STUDY PERFORMED BY DR. ZEPP.

A. The article Mr. D'Ascendis references from Dr. Zepp does not recreate Dr. Wong's study; it simply speculates on other possible reasons for his results and references the results of two other studies. The first study, completed by the California Public Utilities Commission Staff in 1991, is not included in the article, and, therefore, Dr. Zepp's opinions cannot be properly evaluated. Dr. Zepp also draws his conclusions about an entire industry based on the second study, which examines the effects of size on only four water utility companies. This article does not contain enough credible evidence to refute Dr. Wong's findings.

Q. HAS MR. D'ASCENDIS PERFORMED ANY STUDIES IN SUPPORT OF HIS REQUESTED SIZE ADJUSTMENT?

A. Yes, Mr. D'Ascendis conducts two studies regarding size and risk for utility companies, demonstrated by two scatterplots. He uses these studies in an attempt to justify his application of a 12-basis point size adjustment to the recommended cost of equity.[54]

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[53] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 100.

[54] UGI Gas Statement No. 8, pp. 58-59.

Q. DID THE COMMISSION AWARD A SIZE ADJUSTMENT IN THE REFERENCED COMMISSION ORDER FOR CITIZENS' ELECTRIC COMPANY?

A. No. The Commission did not, in fact, award an explicit 100-basis point size adjustment as the Commission determined that there was not enough evidence as to whether size is specifically a risk for utilities. The Commission stated:

> Consistent with the foregoing discussion, like the ALJs, we shall not specify an exact size adjustment. Instead, we shall adopt the ALJs' recommendation that Citizens' be awarded a DCF cost of common equity of 9.49%. In our view, this cost of equity is reasonable and strikes an appropriate balance by recognizing the general inverse relationship between a company's size and its risk, while acknowledging that there is not substantial evidence in the record to prove that an explicit size basis point adjustment is warranted in this case.[55]

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 5 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 5 additional basis points to the Company's cost of equity:

[55] *Pa. PUC v. Citizens Electric Company of Lewisburg, PA*, Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 103-104.

UGI Utilities, Inc. - Gas Division	
Claimed Equity Percentage of Capital Structure	54.25%
Additional Basis Points to the Calculated Cost of Equity for a "Business Risk Adjustment"	0.05%
Claimed Rate Base*	$4,319,352,000
Impact Prior to Gross Up (0.5425 x 0.0005 x $4,319,352,000)	$1,171,624
Gross Revenue Conversion Factor**	1.392298
Total Impact ($1,171,624 x 1.392298)	**$1,631,250**

*UGI Exhibit A, Schedule A-1, Line 9.
**UGI Exhibit A, Schedule A-1, Line 24.

In this example, an addition of 5 basis points to the cost of equity would force ratepayers to fund unwarranted additional amounts of $1,631,250 annually.

Flotation Cost Adjustment

Q. WHAT IS A FLOTATION COST?

A. Flotation costs are the expenses incurred when a company issues securities such as stocks or bonds when raising capital. These expenses can include legal fees, underwriting fees, auditing fees, administrative costs, or any other necessary and justifiable cost in the issuance process.

Q. EXPLAIN THE FLOTATION COST ADJUSTMENT MR. D'ASCENDIS IS PROPOSING IN THIS PROCEEDING.

A. Mr. D'Ascendis added 12 basis points to his cost of common equity for a flotation cost adjustment. He opines that UGI Gas should be able to recover flotation costs in the form of raising the common equity cost rate, as these costs are a permanent loss of investment to the utility and cannot be recovered without an adjustment to the common equity cost rate.[56]

Q. DO YOU AGREE WITH MR. D'ASCENDIS' DISCUSSION REGARDING THE POTENTIAL IMPACT OF STOCK ISSUE FLOTATION COSTS ON THE ROE?

A. No. Generally, the flotation costs of the parent company are accounted for and recovered as O&M expenses or amortized over a certain period in the books of the issuer company. UGI Gas does not issue its own stock independent of the parent company to the general public in the capital market, and the parent company issues stocks for a variety of reasons and uses, so it cannot be assumed they are entirely issued and used for the benefit of UGI Gas. As of the writing of this testimony, I am unaware that UGI Gas' parent company plans to issue new stocks during the FPFTY, when the new rates will be effective. Mr. D'Ascendis' claim for the flotation cost impact in recommending an ROE for FPFTY ratemaking is

[56] UGI Gas Statement No. 8, pp. 61-65.

improper and unsupported, when the claim for such cost is based on the historical flotation costs of the parent company. Therefore, it is inappropriate to present the potential flotation cost impact of 0.12% to support the claimed ROE of 10.75% in this proceeding. Lastly, I am unaware of any instance in the recent past where the Commission has specifically authorized a flotation cost adjustment for the parent company's stock issuance expenses for determining a utility's cost of equity in a base rate proceeding.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 12 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 12 additional basis points to the Company's cost of equity:

UGI Utilities, Inc. - Gas Division	
Claimed Equity Percentage of Capital Structure	54.25%
Additional Basis Points to the Calculated Cost of Equity for a "Flotation Cost Adjustment"	0.12%
Claimed Rate Base*	$4,319,352,000
Impact Prior to Gross Up (0.5425 x 0.0012 x $4,319,352,000)	$2,811,898
Gross Revenue Conversion Factor**	1.392298
Total Impact ($2,811,898 x 1.392298)	**$3,915,000**

*UGI Exhibit A, Schedule A-1, Line 9.
**UGI Exhibit A, Schedule A-1, Line 24.

In this example, an addition of 12 basis points to the cost of equity would force ratepayers to fund unwarranted additional amounts of $3,915,000 annually.

OVERALL RATE OF RETURN RECOMMENDATION

Q. WHAT IS THE COMPANY'S PROPOSED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. The Company recommends a cost of equity of 10.75% and an overall rate of return of 8.20%.[57]

[57] UGI Gas Exhibit B, Schedule DWD-1, p. 1.

Q. WHAT IS I&E'S RECOMMENDED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. I&E Exhibit No. 2, Schedule 1, shows the calculation of an appropriate cost of equity to be 9.81% for the Company with an overall rate of return for UGI Gas of 7.69%. The difference in UGI Gas' requested ROE of 10.75% and I&E's recommended ROE of 9.81% is 0.94%, or 94 basis points.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 94 BASIS POINTS TO THE COST OF EQUITY?

A. The example below illustrates the impact of 94 additional basis points to the Company's cost of equity:

UGI Utilities, Inc. - Gas Division	
Claimed Equity Percentage of Capital Structure	54.25%
Difference in Return on Equity Between I&E's Recommendation and UGI Gas' Requested ROE (10.75% - 9.81% = 0.94%)	0.94%
Claimed Rate Base*	$4,319,352,000
Impact Prior to Gross Up (0.5425 x 0.0094 x $4,319,352,000)	$22,026,536
Gross Revenue Conversion Factor**	1.392298
Total Impact ($22,026,536 x 1.392298)	**$30,667,501**
*UGI Exhibit A, Schedule A-1, Line 9. **UGI Exhibit A, Schedule A-1, Line 24.	

In this example, an addition of 94 basis points to the cost of equity would force ratepayers to fund an unwarranted additional amount of $30,667,501.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANY'S PROPOSED RETURN ON EQUITY?

A. Yes. First, to reiterate, the data taken from S&P Global Market Intelligence, as cited above in the "*Capital Structure*" section, illustrates that the average authorized return on equity decided between January 2025 and March 2026 was 9.70%, and the average authorized equity percentage during that same span was

51.62%.[58] UGI Gas' recommendations far exceed these averages, and the ROE position recommended by I&E of 9.81% is still above the national average during the aforementioned span.

Second, when asked, Mr. D'Ascendis indicated he was unaware if any natural gas distribution utilities throughout the contiguous United States were granted a Commission authorized return of 10.75% or higher cost of common equity in the past two years.[59]

Third, as cited to above, the Commission has recently commented on the equity heavy capital structure of other utility companies, and specifically asked that UGI Gas' capital structure be subject to a careful evaluation.

Fourth, UGI Gas has consistently generated a return on equity significantly higher than the national average in recent years, posting returns of 11.4%, 11.2%, and 10.4% in fiscal years 2023, 2024, and 2025, respectively.[60]

Finally, I believe it is important to consider the impact of what the Company's excessive return on equity request of 10.75% would have on rates. Any additional basis points beyond the I&E recommended ROE of 9.81% would be excessive and would put an enormous burden on ratepayers during these tough economic times.

[58] I&E Exhibit No. 2, Schedule 6.
[59] I&E Exhibit No. 2, Schedule 22.
[60] I&E Exhibit No. 2, Schedule 23.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A
Drew Breuning
Professional and Educational Experience

Professional Experience

October 2024 – Present
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
Bureau of Investigation and Enforcement

Education and Training

Shippensburg University of Pennsylvania, Shippensburg, Pennsylvania
Bachelor of Science, Business Administration, Concentration in Finance, 2022

Investment Management Program, Shippensburg University, 2022

Utility Specific Training/Conferences:

SURFA Annual Financial Forum – Charlotte, NC – 2025

Testimony Submitted

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2025-3057164 – PPL Electric Utilities Corporation
- Docket No. R-2025-3053442 – The York Water Company
- Docket No. R-2024-3052716 – UGI Utilities, Inc. – Gas Division

I&E Statement No. 2
Witness: Drew Breuning

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Exhibit to Accompany

the

Direct Testimony

Of

Drew Breuning

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

I&E
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	9.81%	5.32%
Total	100.00%		7.69%

I&E PROXY GROUP

No.	Company Name	Ticker	Industry	VL Report	Deregulated Market	% Revenue	M&A Activity
1	Atmos Energy Corporation	ATO	Natural Gas	Yes	Yes	>50	None
2	Chesapeake Utilities Corp.	CPK	Natural Gas	Yes	Yes	>50	None
3	New Jersey Resources Corporation	NJR	Natural Gas	Yes	Yes	>50	None
4	NiSource Inc.	NI	Natural Gas	Yes	Yes	>50	None
5	Northwest Natural Holding Company	NWN	Natural Gas	Yes	Yes	>50	None
6	ONE Gas, Inc.	OGS	Natural Gas	Yes	Yes	>50	None

Proxy Group Capital Structure

	2024		2023		2022		2021		2020		Average
Atmos Energy Corporation											
Long-term Debt	$ 8,085.015	39.94%	$ 6,833.663	38.60%	$ 5,944.948	38.69%	$ 5,124.950	39.33%	$ 4,732.850	41.07%	39.53%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	12,157.669	60.06%	10,870.064	61.40%	9,419.091	61.31%	7,906.889	60.67%	6,791.203	58.93%	60.47%
	20,242.684	100.00%	17,703.727	100.00%	15,364.039	100.00%	13,031.839	100.00%	11,524.053	100.00%	100.00%
Chesapeake Utilities Corp.											
Long-term Debt	1,270.400	47.75%	1,197.625	49.01%	590.780	41.50%	558.474	41.91%	518.371	42.65%	44.56%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	1,390.200	52.25%	1,246.104	50.99%	832.801	58.50%	774.130	58.09%	697.085	57.35%	55.44%
	2,660.600	100.00%	2,443.729	100.00%	1,423.581	100.00%	1,332.604	100.00%	1,215.456	100.00%	100.00%
New Jersey Resources Corporation											
Long-term Debt	3,038.767	58.00%	2,916.040	59.43%	2,623.784	59.08%	2,303.527	58.55%	2,354.496	56.07%	58.23%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	2,200.443	42.00%	1,990.735	40.57%	1,817.210	40.92%	1,630.862	41.45%	1,844.692	43.93%	41.77%
	5,239.210	100.00%	4,906.775	100.00%	4,440.994	100.00%	3,934.389	100.00%	4,199.188	100.00%	100.00%
NiSource Inc.											
Long-term Debt	12,092.700	58.20%	11,081.300	57.27%	9,555.500	55.78%	9,211.300	57.01%	9,249.700	61.66%	57.98%
Preferred Stock	-	0.00%	486.100	2.51%	1,546.500	9.03%	1,546.500	9.57%	880.000	5.87%	5.40%
Common Equity	8,684.200	41.80%	7,783.500	40.22%	6,028.900	35.19%	5,400.800	33.42%	4,872.200	32.48%	36.62%
	20,776.900	100.00%	19,350.900	100.00%	17,130.900	100.00%	16,158.600	100.00%	15,001.900	100.00%	100.00%
Northwest Natural Holding Company											
Long-term Debt	1,755.269	55.89%	1,502.602	53.93%	1,325.132	52.99%	1,124.055	54.59%	940.702	51.42%	53.76%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	1,385.371	44.11%	1,283.838	46.07%	1,175.441	47.01%	935.146	45.41%	888.733	48.58%	46.24%
	3,140.640	100.00%	2,786.440	100.00%	2,500.573	100.00%	2,059.201	100.00%	1,829.435	100.00%	100.00%
ONE Gas, Inc.											
Long-term Debt	2,396.686	43.57%	2,174.701	44.02%	2,679.143	50.90%	3,707.778	61.21%	1,613.228	41.94%	48.33%
Preferred Stock	-	0.00%	-	0.00%	-	0.00%	-	0.00%	-	0.00%	0.00%
Common Equity	3,104.548	56.43%	2,765.877	55.98%	2,584.426	49.10%	2,349.532	38.79%	2,233.311	58.06%	51.67%
	5,501.234	100.00%	4,940.578	100.00%	5,263.569	100.00%	6,057.310	100.00%	3,846.539	100.00%	100.00%
Five-Year Average Capital Structure											
Long-term Debt	50.40%		Maximum	58.23%	Minimum	39.53%					
Preferred Stock	0.90%										
Common Equity	48.70%		Minimum	36.62%	Maximum	60.47%					
	100.00%										

Source:

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, Pennsylvania 17120

Pennsylvania Public Utility Commission
v.
UGI Utilities, Inc. – Gas Division

Public Meeting of February 19, 2026
3059523-TUS
Docket No. R-2025-3059523

STATEMENT OF VICE CHAIR KIMBERLY BARROW

Before us for consideration is the proposed rate increase request by UGI Utilities, Inc. – Gas Division (UGI or Company). UGI proposes an increase of $99.368 million (8.05%) in additional annual revenues to become effective March 29, 2026. The proposal will result in an increase in a residential customer's bill using 68.7 Ccf per month from $113.64 to $123.55 (8.7%).

I vote to approve the suspension and investigation of this filing, pursuant to 66 Pa. C.S. § 1308(d). However, I urge the parties to take a critical look at the Company's requested rate of return and return on equity (ROE) as well as the capital structure (common equity ratio and debt capital) to ensure reasonableness. Deviations in each of these items translate into millions of dollars charged to customers of all rate classes. Too often, the relationship between debt and ROE to cost of debt and capital is asserted as a general matter from basic economic principle alone. But, those relationships are not established empirically. That empirical relationship must periodically be re-established. Therefore, I believe a careful and detailed review of UGI's claimed capital structure and ROE is warranted.

February 19, 2026

Kimberly Barrow, Vice Chair

PENNSYLVANIA PUBLIC UTILITY COMMISSION
Harrisburg, Pennsylvania 17120

Pennsylvania Public Utility Commission, et al.	**Public Meeting of December 4, 2025**
v.	**3053499-OSA**
Columbia Gas of Pennsylvania, Inc.	**Docket No. R-2025-3053499**

STATEMENT OF VICE CHAIR KIMBERLY BARROW

Before us for consideration is the proposed rate increase request by Columbia Gas of Pennsylvania, Inc. (Columbia Gas or Company). Columbia Gas proposed an increase of $110.4 million (12.02%) in additional annual revenues based on a fully projected future test year (FPFTY) ending December 31, 2026. The proposal would have resulted in an increase in a residential customer's bill using 70 Therms per month from $138.52 to $152.29 (an increase of $15.77 or 11.38%). Columbia Gas also requested an increase in its residential customer charge from $17.25 to $31.97 (an increase of $14.72 or 85.2%).

In their Recommended Decision, Administrative Law Judges (ALJs) Jeffery A. Watson and Chad L. Allensworth recommended that the Commission deny the Company's rate increase request in its entirety or alternatively grant an increase of $66,424,574. Exceptions and Reply Exceptions were filed.[1]

Below are a few issues of concern I would like to highlight.

Frequency of Rate Increase Filings:

The record in this case indicates that since 2008 Columbia Gas has requested an increase almost on an annual basis, including five rate increase requests since 2020.[2] Columbia Gas' rates have increased by almost $500 million during this period. The record further shows that Columbia Gas has the highest rates in the state and the highest revenue per unit of natural gas in the state and the third highest for the 25 natural gas distribution companies (NGDCs) offering service in the mid-Atlantic region, surpassed only by NGDCs offering service to New York City.[3] Columbia Gas' rates outpace inflation. Over the last 20 years, Columbia's residential customer rates for average heating customers (70 therms per month) have increased by 121% (from $47.58 in 2005 to $105.09 in 2025). During this period, the household income for a family of four at 150% FPL only increased 60% (from $30,000 to $48,225 per year). Columbia Gas has also filed 12 rate

[1] The Parties to this proceeding include Columbia Gas, the Office of Consumer Advocate (OCA), The Pennsylvania State University (PSU), the Commission's Bureau of Investigation and Enforcement (I&E), the OCA, the Office of Small Business Advocate (OSBA), and the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA).

[2] Including the instant proceeding, the Company has requested a rate increase twelve times since 2009: 2009, 2010, 2012, 2014, 2015, 2016, 2019, 2020, 2021, 2022, 2024, and now 2025. *See* OCA St. 5 at 7; OSBA M.B. at 5, Table IEc-1; Table 2, *supra*. Further, as noted in Table 2, the instant rate proceeding is the Company's thirteenth since 2008.

[3] OCA Ex. MWD-7; I&E St. 2 at 9; OCA M.B. at 36; OCA R.B. at 12; OCA Exh. MWD-7.

cases during this period totaling approved distribution rate increases of over $487 million.[4]

While I understand that Columbia Gas is entitled to recovery of the cost of investments made to its system, the Company's utilization of the FPFTY, as authorized under 66 Pa.C.S. § 315, and the availability of the distribution system improvement charge (DSIC), as authorized under 66 Pa.C.S. § 1350 and other rate recovery mechanisms, should be enough incentives to discourage Columbia Gas' current near-annual frequency of rate increase requests.

Capital Structure:

Columbia Gas requested a capital structure of 54.4% common equity and 45.60% debt (43.28% long-term debt and 2.32% short-term debt), along with a return on equity (ROE) of 11.35%. Although I&E accepts the Company's proposed capital structure, the OCA and CAUSE-PA, in opposition, argued that the Commission should instead award a hypothetical capital structure of 50% equity and 50% debt (47.68% long-term debt and 2.32% short-term debt).[5] According to the OCA, the average capital structure mix for the proxy group used in this case as shown on the Value Line consists of 55% debt and 45% equity, the inverse of the ratio proposed by Columbia. [6]

Here, the record clearly reflects that the proxy group's capital structure is composed of less equity than Columbia Gas' capital structure, highlighting reduced risk for the Company when compared to that of the proxy group, and, therefore, suggesting the need for a lower ROE for Columbia Gas. I agree with the OCA that the discrepancy between Columbia Gas' capital structure and the proxy group necessitates an adjustment to the Company's capital structure since Columbia Gas' equity profile has less financial risk than the proxy group. A 50/50 capital structure in this case is equal to the proxy group's average capital structure. [7] Also noteworthy, CAUSE-PA argued that if the Commission were to apply a hypothetical capital structure of 50% equity and 50% debt, the overall rate of return at the Company's desired ROE of 11.35% would be reduced by 0.27% (from 8.55% to 8.28%), which would have reduced the Company's overall annual revenue requirement increase by $17.7 million, or from the proposed increase of $110.5 million sought by Columbia to $92.8 million.[8] CAUSE-PA and the OCA propose an overall rate of return of 7.06%.[9]

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[4] CAUSE-PA St. 2 at 21.
[5] OCA M.B. at 126; OCA St. 3 at 58; OCA Exh. DJG-16.
[6] OCA M.B. at OCA St. 3 at 50.
[7] Adoption of the OCA's recommended capital structure and ROE would result in a revenue requirement reduction of $54.6 million. OCA St. 3 at 3-4, 50. I agree with the OCA that in *Riverton Consol. Water Co. v. Pa. PUC, 140 A.2d 114 at 121 (Pa. Super. 1958)*, the Superior Court determined that the Commission may make adjustments to a utility's capital structure where circumstances indicate that the actual capital structure may be unfair to customers, such as when the actual capital structure may be weighted too heavily to the debt side or the equity side. See OCA M.B. at 125.
[8] CAUSE-PA M.B. at 35-38.
[9] The OCA's proposed overall rate of return was based upon a weighted average of a 5.20% rate of return on long-term debt, a 5.00% rate of return on short-term debt, and an 8.9% rate of return on common equity. OCA M.B. at 123, 127; OCA St. 3 at 58.

It is clear from the arguments put forward by the Parties in opposition to the Company's proposed capital structure that a 50% equity and 50% debt capital structure is a better representation of the Company's **actual** financial risk and would have resulted in millions of dollars in reduced revenue requirement for the Company and resultant lower rates for Columbia Gas' customers.

Rate of Return on Equity:

Columbia Gas proposed a rate of return on common equity of 11.35% inclusive of the Company's requested upward adjustment of 0.25% for management effectiveness.[10] As a result of its DCF analysis, I&E recommended a cost of common equity of 10.51%.[11] The OCA recommended a cost of common equity of 8.90%, based on its CAPM model and the use of a hypothetical capital structure. The OCA noted that an ROE of 8.90% and overall rate of return of 7.06% are sufficient to ensure Columbia Gas' ability to attract capital and continue investment to provide safe and reliable service, while guarding the interests of consumers.[12] The ALJs rejected Columbia Gas' proposed rate of return on common equity of 11.35% and adopted I&E's proposed DCF ROE of 10.51% ROE.[13]

I believe an ROE lower than the ALJs' recommended 10.51% is more appropriate in this case, given Columbia Gas' unique lack of regulatory lag, associated reduced business risk, and the commensurate impact of the Company's nearly annual rate increases in the past five years on customers' rates. Using informed judgment, an ROE of 9.6% is more appropriate. The most recent five-year average of I&E's proxy group companies' capital structure ranges from 39.33% to 57% long-term debt, 0.51% to 12.82% short-term debt, and 35.96% to 60.16% common equity, with an overall five-year average of 47.42 long-term debt, 7.85% short-term debt, and 44.73% common equity.[14] Since the proxy group's capital structure is composed of less equity than Columbia's capital structure (or the hypothetical capital structure) it is appropriate to adjust the equity return to account for the reduced risk of a capital structure that employs more equity. I&E's DCF results range from 9.06% to 11.68% (using an average dividend yield and average growth estimate for each company) with an average of 10.51% and a composite CAPM ROE of 9.935.

Based upon consideration of the competing evidence provided to the record, I believe an ROE that is in the range of the bottom of I&E's DCF range and the Composite CAPM ROE is appropriate. The 9.60% ROE is also an approximate median number between the OCA's proposed ROE of 8.90% and I&E's proposed ROE of 10.51%. With an ROE of 9.60% along with a 50/50 capital structure, the overall rate of return would be 7.40%, resulting in an overall rate increase of approximately $30,573,357. Accordingly, I would support an ROE of 9.60%.

Smart Remote Methane Detection Pilot: I&E recommended a Smart Remote Methane Detector pilot program in a region where Columbia has risky pipe for the installation of

[10] Columbia Gas St. 8 at 9-10.
[11] I&E M.B. at 40-41.
[12] OCA R. Exc. at 10-11; OCA M.B. at 137.
[13] R.D. at 337-38.
[14] I&E M.B at 37; I&E St. 2 at 20, citing I&E Exh. 2, Sch. 2.

500 to 1,000 Smart Remote Methane Detectors (SRMDs). Columbia stated that it could not commit to the Pilot as outlined by I&E, citing significant IT infrastructure costs and concerns, but was willing to evaluate technologies associated with the integration of Automated Metering Infrastructure and SRMDs for potential future deployment.

I support directing Columbia to implement an internal study to determine whether a methane detection pilot program would be feasible and how it would be implemented. With affordability always on our minds, it is very important for the company to fully understand the potential costs associated with the pilot prior to implementation. The usefulness and safety benefits of methane detectors are tremendous, allowing the ability of real-time smart reporting technology to simultaneously notify the customer and the emergency response officials of a potentially hazardous situation. I want to take the opportunity to thank I&E for putting forth this proposal and for Columbia to be willing to evaluate the pilot.

Additional CAP Screening: The OCA and CAUSE-PA proposed that Columbia conduct initial screening for all applicants applying for service or when transferring service to determine if they qualify as a low-income customer or may be eligible for assistance, such as customer assistance program (CAP). The record indicates that only 20,988 customers, or 23% of the estimated Columbia Gas' low-income customers, were enrolled in CAP and that additional screening is appropriate. I support this proposal and agree that additional screening is needed, and that any tool we can use to nudge customers into a healthy financial relationship with their utility is beneficial for everyone.

December 4, 2025

Kimberly Barrow, Vice Chair

I&E MODIFIED

STATE	COMPANY	PARENT TICKER	DOCKET NO.	REQUESTED ROE	REQUESTED EQUITY %	AUTHORIZATION DATE	DECISION TYPE	AUTHORIZED ROE	AUTHORIZED EQUITY %
Arizona	Southwest Gas Corp.	SWX	D-G-01551A-23-0341	9.65	48.50	3/27/2025	Settled	9.84	48.50
Arizona	UNS Gas Inc.	FTS	D-G-04204A-24-0237	10.25	55.55	2/19/2026	Fully Litigated	9.61	55.55
California	Southern California Gas Co.	SRE	A-25-03-011	11.00	52.00	12/18/2025	Fully Litigated	9.78	52.00
Connecticut	Yankee Gas Services Co.	ES	D-24-12-01	10.80	53.81	11/5/2025	Fully Litigated	9.32	53.00
District of Columbia	Washington Gas Light Co.	ALA	FC-1180	10.50	52.49	11/20/2025	Fully Litigated	9.65	52.49
Delaware	Chesapeake Utilities Corp.	CPK	D-24-0906	11.50	52.14	6/18/2025	Settled	9.60	52.00
Delaware	Delmarva Power & Light Co.	EXC	D-24-1044	10.65	50.51	12/17/2025	Settled	9.60	50.51
Florida	Peoples Gas System	EMA	D-20250029-GU	10.91	NA	10/7/2025	Settled	10.30	48.10
Idaho	Avista Corp.	AVA	C-AVU-G-25-01	10.40	50.00	8/29/2025	Settled	9.60	50.00
Idaho	Intermountain Gas Co.	MDU	C-INT-G-25-02	10.80	50.00	12/30/2025	Settled	9.50	50.00
Illinois	Ameren Illinois	AEE	D-25-0084	10.70	52.00	11/19/2025	Fully Litigated	9.60	50.00
Illinois	Northern Illinois Gas Co.	SO	D-25-0055	10.35	54.59	11/19/2025	Fully Litigated	9.60	50.00
Kansas	Atmos Energy Corp.	ATO	D-26-ATMG-026-RTS	10.80	59.86	2/26/2026	Settled	NA	NA
Kansas	Black Hills Kansas Gas Utility	BKH	D-25-BHCG-298-RTS	10.50	50.44	7/24/2025	Settled	NA	NA
Kentucky	Atmos Energy Corp.	ATO	C-2024-00276	10.95	60.88	8/11/2025	Fully Litigated	9.75	53.50
Kentucky	Delta Natural Gas Co.	WTRG	C-2024-00346	10.95	52.76	7/1/2025	Settled	9.75	52.76
Kentucky	Duke Energy Kentucky Inc.	DUK	C-2025-00125	10.75	52.65	12/23/2025	Settled	9.80	52.65
Kentucky	Louisville Gas & Electric Co.	PPL	C-2025-00114 (gas)	10.95	52.93	2/16/2026	Settled	9.78	53.00
Louisiana	Delta North LA Gas Co LLC		D-U-37346 (Arkla)	NA	NA	4/25/2025	Fully Litigated	9.95	52.00
Louisiana	Delta South LA Gas Co LLC		D-U-37345 (Entex)	NA	NA	4/25/2025	Fully Litigated	9.95	52.00
Massachusetts	Boston Gas Co.	NG.	DPU 25-74	NA	NA	9/30/2025	Fully Litigated	NA	NA
Massachusetts	Fitchburg Gas & Electric Light	UTL	DPU 25-24	NA	NA	6/20/2025	Fully Litigated	NA	NA
Massachusetts	NSTAR Gas Co.	ES	DPU 25-53	NA	NA	10/29/2025	Settled	NA	NA
Maryland	Columbia Gas of Maryland Inc	NI	C-9754	11.05	52.17	4/22/2025	Fully Litigated	9.80	52.17
Michigan	Consumers Energy Co.	CMS	C-U-21806	10.25	42.58	9/30/2025	Fully Litigated	9.80	41.95
Minnesota	CenterPoint Energy Resources	CNP	D-G-008/GR-23-173	10.30	52.49	5/29/2025	Settled	NA	NA
Minnesota	Northern States Power Co.	XEL	D-G-002/GR-23-413	10.20	52.50	2/13/2025	Settled	9.60	52.50
Missouri	Empire District Gas Co.	AQN	C-GR-2025-0212	NA	NA	5/22/2025	Withdrawn or Rejected	NA	NA
Missouri	Empire District Gas Co.	AQN	C-GR-2026-0059	NA	NA	10/28/2025	Withdrawn or Rejected	NA	NA
Missouri	Spire Missouri Inc.	SR	C-GR-2025-0107	10.50	55.00	9/3/2025	Settled	NA	NA
Missouri	Union Electric Co.	AEE	C-GR-2024-0369	10.25	52.00	7/16/2025	Settled	NA	NA
Mississippi	Atmos Energy Corp.	ATO	D-2025-UN-59	10.41	60.00	11/4/2025	Fully Litigated	9.40	50.00
Montana	MDU Resources Group	MDU	D-2024-05-061	10.80	50.16	10/8/2025	Settled	9.60	50.16
Montana	NorthWestern Energy Group	NWE	D-2024-05-053 (gas)	10.80	47.84	11/19/2025	Settled	9.60	47.84
North Carolina	Piedmont Natural Gas Co.	DUK	D-G-9 Sub 837	10.50	53.00	1/7/2025	Settled	9.80	52.30
North Carolina	Public Service Co. NC	ENB	D-G-5, Sub 686	10.60	56.67	12/9/2025	Settled	9.65	54.00
Nebraska	Black Hills Nebraska Gas LLC	BKH	D-NG-124	10.50	50.52	12/9/2025	Settled	9.85	50.52
Nebraska	NorthWestern Energy Group	NWE	D-NG-0122	10.70	53.13	6/24/2025	Settled	9.55	NA
New Hampshire	Liberty Utilities EnergyNorth	AQN	D-DG-23-067	10.35	55.00	8/26/2025	Settled	9.30	52.00
New York	Central Hudson Gas & Electric	FTS	24-G-0462	10.00	48.00	8/14/2025	Settled	9.50	48.00
New York	Consolidated Edison Co.	ED	C-25-G-0073	10.00	48.00	1/22/2026	Settled	9.40	48.00
New York	Corning Natural Gas Corp.		C-24-G-0447	10.40	48.00	6/12/2025	Settled	9.50	48.00
New York	Niagara Mohawk Power Corp.	NG.	C-24-G-0323	10.00	48.00	8/14/2025	Settled	9.50	48.00
New York	Orange & Rockland Utlts Inc.	ED	C-24-G-0061	10.25	50.00	3/20/2025	Settled	9.75	48.00
Ohio	The East Ohio Gas Co.	ENB	C-23-0894-GA-AIR	9.85	58.00	6/26/2025	Fully Litigated	9.79	51.87
Ohio	Vectren Energy Delivery OH LLC	CNP	C-24-0832-GA-AIR	10.40	54.13	1/7/2026	Settled	9.79	52.90
Oklahoma	Oklahoma Natural Gas Co	OGS	Ca-PUD2025-000011	NA	NA	7/23/2025	Settled	NA	NA
Oregon	Avista Corp.	AVA	D-UG-519	10.40	50.00	5/23/2025	Settled	9.50	50.00
Oregon	Northwest Natural Gas Co.	NWN	D-UG-520	10.40	52.00	10/24/2025	Settled	9.50	50.00
Pennsylvania	Columbia Gas of Pennsylvania	NI	D-R-2025-3053499	11.35	54.40	12/4/2025	Fully Litigated	10.00	54.40
Pennsylvania	UGI Utilities Inc.	UGI	D-R-2024-3052716	11.20	54.11	9/11/2025	Settled	NA	NA
Tennessee	Atmos Energy Corp.	ATO	D-25-00007 (ARM)	NA	61.05	7/15/2025	Settled	NA	61.05
Tennessee	Chattanooga Gas Co.	SO	D-25-00028 (ARM)	NA	49.23	9/29/2025	Settled	NA	NA

Tennessee	Piedmont Natural Gas Co.	DUK	D-25-00036 (ARM)	NA	47.89	11/25/2025	Settled	NA	47.89
Texas	Atmos Energy Corp.	ATO	D-OS-24-00019196 (Mid-Tex)	10.85	60.97	6/17/2025	Settled	9.80	60.97
Texas	Atmos Energy Corp.	ATO	D-OS-24-00018879(West Texas)	10.85	60.97	5/13/2025	Settled	9.80	60.97
Texas	Texas Gas Service Co.	OGS	D-OS-25-00028202	10.40	59.92	2/5/2026	Settled	9.80	59.92
Utah	Questar Gas Co.		D-25-057-06	10.60	53.00	12/24/2025	Settled	NA	NA
Virginia	Columbia Gas of Virginia Inc	NI	C-PUR-2024-00030	10.85	42.76	5/15/2025	Settled	9.75	43.17
Virginia	Roanoke Gas Co.	RGCO	C-PUR-2024-00006	10.35	58.61	4/10/2025	Settled	9.90	58.18
Virginia	Virginia Natural Gas Inc.	SO	C-PUR-2024-00048	10.45	54.92	12/17/2025	Settled	9.85	49.35
Washington	Cascade Natural Gas Corp.	MDU	D-UG-240008	10.50	50.29	2/24/2025	Settled	9.50	49.50
Washington	Puget Sound Energy Inc.		D-UG-240005	10.50	51.00	1/15/2025	Fully Litigated	9.90	50.00
Wisconsin	Madison Gas & Electric Co.	MGEE	D-3270-UR-126 (Gas)	10.00	56.04	11/20/2025	Settled	9.80	56.05
Wisconsin	Northern States Power Co.	XEL	D-4220-UR-127 (Gas)	10.00	53.50	11/6/2025	Fully Litigated	9.80	NA
Wisconsin	Wisconsin Power & Light Co	LNT	D-6680-UR-125 (Gas)	9.90	55.27	11/6/2025	Settled	9.80	54.53
West Virginia	Hope Gas Inc.		C-25-0417-G-42T	11.00	50.00	2/10/2026	Settled	9.75	NA
Wyoming	MDU Resources Group	MDU	D-30013-415-GR-24	10.80	50.18	6/24/2025	Settled	9.65	50.18
Average				**10.54**	**52.79**			**9.70**	**51.62**

Source:
www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/industry/pastRateCases?Type=1
(Accessed: 3/11/2026)

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RR-1 thru RR-14)
Delivered on February 26, 2026

I&E-RR-8-D

Request:

Confirm or deny whether Mr. D'Ascendis agrees that generally, all other things being similar, a company with a capital structure containing a higher equity ratio faces less financial risk as compared to a company with a capital structure containing a lower equity ratio.

Response:

Confirmed with clarification. Generally, as discussed on page 11, lines 4 through 9 of the Direct Testimony of Dylan W. D'Ascendis, UGI Gas Statement No. 8, the more leverage a company has, the greater the financial risk. However, as stated on page 11, line 10 through 18 of UGI Gas Statement No. 8, the combined business and financial risk of a company (excluding size) is contained in its bond rating. As shown on UGI Gas Exhibit B, Schedule DWD-4, page 3, the Company has a Moody's bond rating of A3, which is comparable in risk to the A3 Moody's average bond rating of the Utility Proxy Group.

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

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RR-1 thru RR-14)
Delivered on February 26, 2026

I&E-RR-7-D

Request:

Reference UGI Gas Statement No. 8, p. 14, lines 4-5, as well as UGI Gas Exhibit A, Schedule B-7. Identify the actual capital structures for UGI Utilities, Inc. – Gas Division, and separately, its parent company UGI Utilities, Inc. for calendar years 2023, 2024, and 2025.

Response:

UGI Utilities, Inc. uses a fiscal year (twelve months ended September 30) to prepare its financial statements and has presented information in this proceeding on a fiscal year basis.

The actual capital structures for UGI Utilities, Inc. for Fiscal Years 2023, 2024 and 2025 are shown on Attachment I&E-RR-7-D. As UGI Utilities, Inc. – Gas Division is not a separate legal entity from UGI Utilities, Inc., its capital structure is the same as that of UGI Utilities, Inc.

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

UGI Utilities, Inc. - Gas Division
Capital Structure Ratios for UGI Utilities, Inc.
As of September 30, 2025, 2024 and 2023

	Fiscal 2025	Fiscal 2024	Fiscal 2023
Capital Structure Ratios			
Based on Permanent Capital			
Long-Term Debt	47.1%	46.6%	43.9%
Common Equity	52.9%	53.4%	56.1%

	2024		
	Interest Charges	**Long-Term Debt**	**Debt Cost**
Atmos Energy Corporation	$ 205.287	$ 8,085.02	2.54%
Chesapeake Utilities Corp.	$ 69.800	$ 1,270.40	5.49%
New Jersey Resources Corporation	$ 135.004	$ 3,038.77	4.44%
NiSource Inc.	$ 557.300	$ 12,092.70	4.61%
Northwest Natural Holding Company	$ 80.092	$ 1,755.27	4.56%
ONE Gas, Inc.	$ 155.435	$ 2,396.69	6.49%
	Range:	**Low**	**2.54%**
		High	**6.49%**
		Average	**4.69%**

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Mergent Bond Record
A-Rated Public Utility Bond Yields

Month	Yield
February 2025	5.73%
March 2025	5.72%
April 2025	5.91%
May 2025	6.05%
June 2025	5.93%
July 2025	5.88%
August 2025	5.77%
September 2025	5.61%
October 2025	5.51%
November 2025	5.62%
December 2025	5.68%
January 2026	5.68%
Average	**5.76%**

Source:
Mergent Bond Record
February 2026

Dividend Yields of Proxy Group

Company	Atmos Energy Corporation	Chesapeake Utilities Corp.	New Jersey Resources Corporation	NiSource Inc.	Northwest Natural Holding Company	ONE Gas, Inc.
Symbol	*ATO*	*CPK*	*NJR*	*NI*	*NWN*	*OGS*
Div	4.24	2.98	2.10	1.28	1.97	2.76
52-wk low	141.59	115.24	43.46	35.64	38.94	69.75
52-wk high	182.69	140.59	54.70	47.05	50.94	86.79
Spot Price	181.72	135.06	53.39	46.47	49.89	85.34
Spot Div Yield	2.33%	2.21%	3.93%	2.75%	3.95%	3.23%
52-wk Div Yield	2.62%	2.33%	4.28%	3.10%	4.38%	3.53%
Average	2.47%	2.27%	4.11%	2.93%	4.17%	3.38%

	Average
Spot Div Yield	**3.07%**
52-wk Div Yield	**3.37%**
Average	**3.22%**

Source: Barron's February 25, 2026
Value Line February 25, 2026

Five-Year Growth Estimate Forecast for Proxy Group (Actual)

Company	Symbol	S&P	Zacks	Value Line	Average
		Source			
Atmos Energy Corporation	ATO	8.36%	7.00%	8.00%	7.79%
Chesapeake Utilities Corp.	CPK	8.15%	NA	8.00%	8.08%
New Jersey Resources Corporation	NJR	8.55%	NA	5.00%	6.78%
NiSource Inc.	NI	8.64%	NA	7.50%	8.07%
Northwest Natural Holding Company	NWN	5.50%	NA	6.00%	5.75%
ONE Gas, Inc.	OGS	7.10%	8.10%	6.00%	7.07%
Average:		**7.72%**	**7.55%**	**6.75%**	**7.25%**

Sources Date:
(From Internet)
February 25, 2026

Expected Market Cost Rate of Equity
Using Data for the Proxy Group Companies

	Adjusted Dividend Yield (1)	Growth Rate (2)	Expected Return on Equity (3=1+2)
Atmos Energy Corporation	2.47%	7.79%	10.26%
Chesapeake Utilities Corp.	2.27%	8.08%	10.34%
New Jersey Resources Corporation	4.11%	6.78%	10.88%
NiSource Inc.	2.93%	8.07%	11.00%
Northwest Natural Holding Company	4.17%	5.75%	9.92%
ONE Gas, Inc.	3.38%	7.07%	10.45%
Average	**3.22%**	**7.25%**	**10.47%**

Minimum ROE	9.92%
Maximum ROE	11.00%

Proxy Group Company	Beta
Atmos Energy Corporation	0.80
Chesapeake Utilities Corp.	0.75
New Jersey Resources Corporation	0.75
NiSource Inc.	0.85
Northwest Natural Holding Company	0.80
ONE Gas, Inc.	0.75
Average beta for CAPM	**0.78**

Source:
Value Line
February 25, 2026

Risk-Free Rate

10-Year Treasury Note	Yield
2Q 2026	4.20
3Q 2026	4.20
4Q 2026	4.20
1Q 2027	4.20
2Q 2027	4.20
2027-2031	4.20
Average	**4.20**

Source:
Blue Chip
January 30, 2026

S&P 500 Historical Return

Year	Return (%)
2025	17.88
2024	25.02
2023	26.29
2022	-18.11
2021	28.71
2020	18.4
2019	31.49
2018	-4.38
2017	21.83
2016	11.96
2015	1.38
2014	13.69
2013	32.39
2012	16
2011	2.11
2010	15.06
2009	26.46
2008	-37
2007	5.49
2006	15.79
2005	4.91
2004	10.88
2003	28.68
2002	-22.1
2001	-11.89
2000	-9.1
1999	21.04
1998	28.58
1997	33.36
1996	22.96
1995	37.58
1994	1.32
1993	10.08
1992	7.62
1991	30.47
1990	-3.1
1989	31.69
1988	16.61
1987	5.25
1986	18.67
1985	31.73
1984	6.27
1983	22.56
1982	21.55
1981	-4.91
1980	32.42
1979	18.44
1978	6.56
1977	-7.18
1976	23.84
1975	37.2
1974	-26.47
1973	-14.66
1972	18.98
1971	14.31
1970	4.01
1969	-8.5
1968	11.06
1967	23.98
1966	-10.06
1965	12.45
1964	16.48
1963	22.8
1962	-8.73
1961	26.89
1960	0.47
1959	11.96
1958	43.36
1957	-10.78
1956	6.56
1955	31.56
1954	52.62
1953	-0.99
1952	18.37
1951	24.02
1950	31.71
1949	18.79
1948	5.5
1947	5.71
1946	-8.07
1945	36.44
1944	19.75
1943	25.9
1942	20.34
1941	-11.59
1940	-9.78
1939	-0.41
1938	31.12
1937	-35.03
1936	33.92
1935	47.67
1934	-1.44
1933	53.99
1932	-8.19
1931	-43.34
1930	-24.9
1929	-8.42
1928	43.61
1927	37.49
1926	11.62
Average	**12.35**

Source:
https://www.slickcharts.com/sp500/returns#google_vignette
Accessed on October 17, 2025

Required Rate of Return on Market as a Whole Forecasted

	Dividend Yield	+	Growth Rate	=	Expected Market Return
Value Line Estimate	2.00%		8.78%	(a)	10.78%
S&P 500 Historical Return					12.35%
Average Expected Market Return				=	**11.57%**

(a) Value Line forecast for the 3 to 5 year index appreciation is 40% ((1+40%)^.25)-1)

Sources:

S&P 500 Historical Rate	1926-2025	12.35%
Value Line Dividend Yield	2/27/2026	2.00%
Valueline Appreciation Potential	2/27/2026	40.00%

CAPM with Forecasted Return

Re		Required return on individual equity security
Rf		Risk-free rate
Rm		Required return on the market as a whole
Be		Beta on individual equity security
Re	**=**	Rf + Be(Rm - Rf)
Rf	**=**	4.20
Rm	**=**	11.57
Be	**=**	0.78
Re	**=**	**9.95**

Sources: Value Line February 25, 2026
Blue Chip January 30, 2026

CAPM Using Kroll ERP & 20-Year U.S. Treasury

Re		Required return on individual equity security
Rf		Risk-free rate
ERP		Equity Risk Premium
Be		Beta on individual equity security
Re	**=**	Rf+Be(ERP)
Rf	**=**	4.65
ERP	**=**	5.00
Be	**=**	0.78
Re	**=**	**8.55**

Sources: Value Line February 25, 2026
Kroll January 30, 2026
CNBC February 25, 2026

Average CAPM Result **9.25**

KROLL

Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 - Present

January 30, 2026

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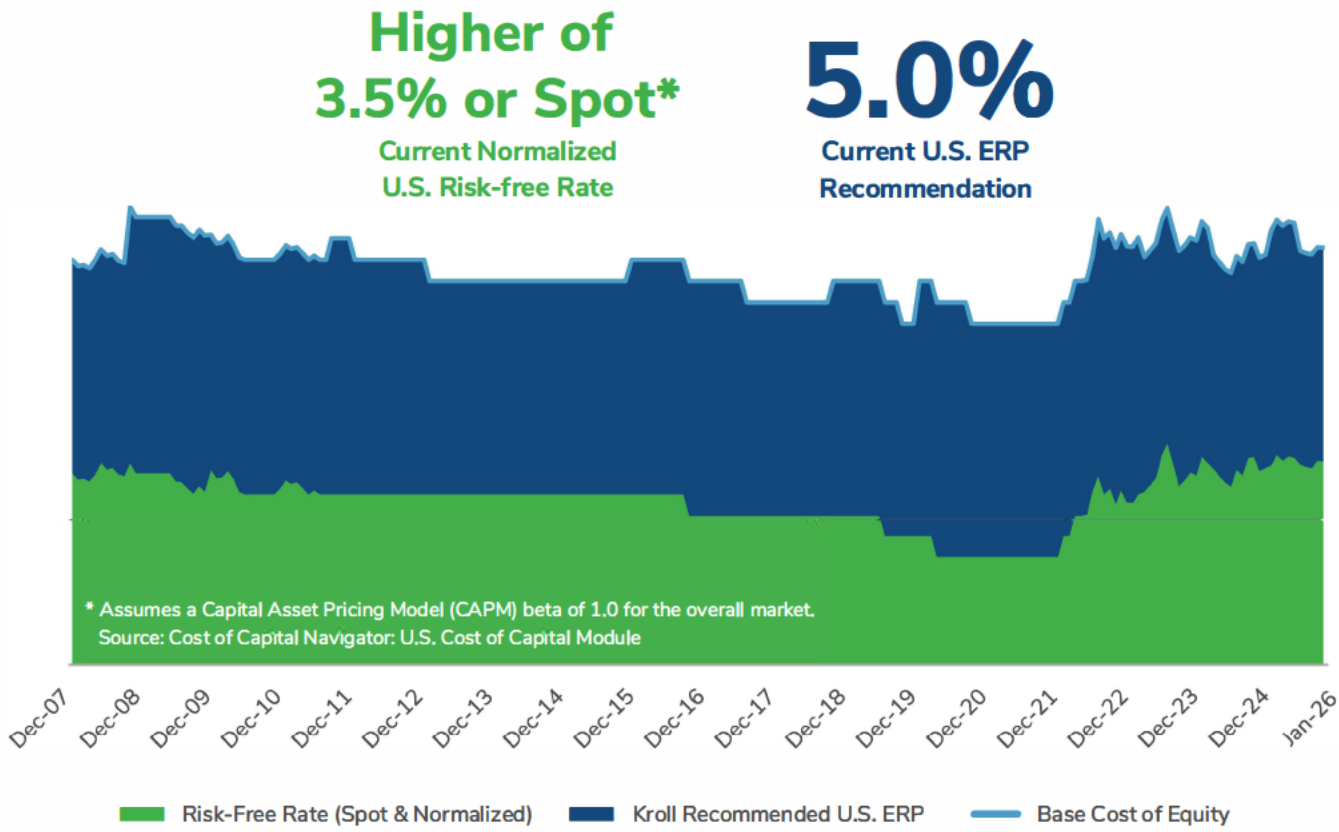

* We recommend using the spot 20-year U.S. Treasury yield as the proxy for the risk-free rate, if the prevailing yield as of the valuation date is higher than our recommended U.S. normalized risk-free rate of 3.5%. This guidance is effective when developing USD-denominated discount rates as of June 16, 2022 and thereafter.

The Equity Risk Premium (ERP) is a key input used to calculate the cost of capital within the context of the Capital Asset Pricing Model ("CAPM") and other models. Kroll regularly reviews fluctuations in global economic and financial market conditions that warrant a periodic reassessment of the ERP and the accompanying risk-free rate.

Duff & Phelps (Rebranded as Kroll) has published its recommended U.S. ERP and corresponding risk-free rate since 2008. Download a table summarizing these recommendations over the period January 2008 – present.

CNBC MARKETS BUSINESS INVESTING TECH POLITICS VIDEO INVESTING CLUB JOIN PRO JOIN LIVESTREAM

U.S. 20 Year Treasury

US20Y:Tradeweb

EXPORT WATCHLIST + LIVESTREAM Squawk on the Street

RT Quote | Exchange

Yield | 9:27 AM EST

4.649% ▲ +0.019

1D 5D 1M 3M 6M YTD 1Y 5Y ALL

+ Comparison 1D Display Studies

LATEST ON U.S. 20 YEAR TREASURY

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RR-1 thru RR-14)
Delivered on February 26, 2026

I&E-RR-9-D

Request:

State whether Mr. D'Ascendis is aware of any instances where the Pennsylvania Public Utility Commission (Commission) relied upon the Risk Premium Model or the PRPM analysis to determine an appropriate cost of equity in a base rate proceeding. If yes, identify the specific cases, including the docket number.

Response:

In Docket No. R-2013-2360798, concerning Columbia Water Company, the Commission states in its disposition that:

In this case, the range of ROE recommendations presented by the Parties based on the DCF methodology is 8.25% to 11.35%. Based on our review of the testimony, data, and cost models presented, we believe that the evidence in this case supports an ROE finding in the reasonable range of 9.25% to 10.25% using the DCF method as the foundation. The equity-heavy capital structure of Columbia indicates that a slightly lower ROE is appropriate. However, the small size of the Company, its management effectiveness, and the results of ROE models other than DCF are all reasons to set a higher ROE. Therefore, within our indicated range of reasonableness, we conclude that a ROE of 9.75% is appropriate for our ratemaking determinations herein.

While not specifically stated, the RPM, to include the PRPM, the ECAPM, and the results of ROE models applied to a Non-Price Regulated Proxy Group were presented in that proceeding.

Furthermore, in Docket No. R-2014-2402324, concerning Emporium Water Company, in the Recommended Decision, Administrative Law Judge Buckley states:

The Company witness, Dylan W. D'Ascendis, recommended that the Commission authorize Emporium the opportunity to earn an overall rate of return of 7.17% based upon a comparable industry group hypothetical capital structure which consists of 46.29% long-term debt and 53.71% common equity at an embedded or actual debt cost rate of 2.68%. He also recommended a common equity cost rate of 11.05%. Emporium Statement No. 2 at 2. While the Commission may see fit to adjust this, these recommendations are at least in the zone of reasonableness and fiscal reality.

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

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RR-1 thru RR-14)
Delivered on February 26, 2026

I&E-RR-4-D

Request:

Reference UGI Statement No. 8, p. 3, lines 7-8:

A. State whether Mr. D'Ascendis is aware of any natural gas distribution utilities throughout the contiguous United States that have been granted a Commission-authorized 10.75% or higher cost of common equity in the past two years.

B. If the answer to I&E-RR-4-D Part A is yes, identify which company/companies have been authorized such cost of common equity, in what jurisdiction, and docket numbers associated with each instance.

Response:

A. Mr. D'Ascendis has not conducted an exhaustive study of all Commission orders, but notes that ENSTAR Natural Gas Co. in Alaska was authorized an 11.88% ROE on April 8, 2024, in Docket D-U-22-081.

B. Please refer to part A of this response.

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

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RR-1 thru RR-14)
Delivered on February 26, 2026

I&E-RR-6-D

Request:

Identify the actual return on equity earned by UGI Utilities, Inc. – Gas Division, and separately, its parent company UGI Utilities, Inc. for calendar years 2023, 2024, and 2025.

Response:

UGI Utilities, Inc. uses a fiscal year (twelve months ended September 30) to prepare its financial statements and has presented information in this proceeding on a fiscal year basis.

Please see the calculated actual returns on equity at Attachment I&E-RR-6-D.

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

UGI Utilities, Inc. - Gas Division
Actual Return on Equity
Twelve Months Ended September 30, 2025, 2024 and 2023

		Fiscal 2025	Fiscal 2024	Fiscal 2023
Rate of Return on Equity				
	UGI Utilities, Inc.	10.5%	11.5%	11.7%
(a)	UGI Utilities, Inc. - Gas Division	10.4%	11.2%	11.4%
(b)	UGI Utilities, Inc. - Electric Division	6.2%	6.9%	2.2%

(a) Fiscal 2024 and Fiscal 2023 are from the Quarterly Earnings Reports previously provided to the Commission by UGI Gas for those periods. UGI Gas was not required to file a report for 12 months ended September 2025; however, the return on equity shown for Fiscal 2025 is calculated in the same manner as the Fiscal 2024 and Fiscal 2023 Quarterly Earnings Report calculations.

(b) Fiscal 2025 and Fiscal 2024 are from Quarterly Earnings Reports previously provided to the Commission for UGI Electric (related to distribution only, excluding transmission). UGI Electric was not required to file a report for 12 months ended September 2023; however, the return on equity shown for Fiscal 2023 is calculated in the same manner as the Fiscal 2025 and Fiscal 2024 Quarterly Earnings Report calculations.

I&E Statement No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Test Year
Reporting Requirements
Present Rate Revenue
Weather Normalization Adjustment
Scale Back of Rates

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached to my direct testimony.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to evaluate UGI Utilities, Inc. – Gas Division's (UGI Gas or Company) request for an annual increase in operating revenue of approximately $99.368 million. My testimony will specifically address issues related to the Weather Normalization Adjustment (WNA), present rate revenue, and scale back of rates.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 3 contains schedules that support my direct testimony.

TEST YEAR

Q. WHAT IS A TEST YEAR AND HOW IS IT USED?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. To meet its burden of proof, a utility has the option of selecting to use a historic test year (HTY), a future test year (FTY), or a fully projected future test year (FPFTY). An HTY is a twelve-month period selected by a company that represents the most recent full year of actual data. The FTY begins the day after the HTY ends and is determined using a combination of actual data and a projection of annualized and normalized estimates of future revenues and expenses and a corresponding measure of value at the end of that period. The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the

application of the full suspension period permitted under Section 1308(d) of the Public Utility Code. The FPFTY is made up entirely of projections forecasted by the company.

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. UGI Gas has selected the year ending September 30, 2025, as the HTY, the year ending September 30, 2026, as the FTY, and the year ending September 30, 2027, as the FPFTY.[1]

Q. WHAT TEST YEAR HAS THE COMPANY BASED ITS REVENUE REQUIREMENT UPON IN THIS PROCEEDING?

A. UGI Gas based its requested revenue requirement on the FPFTY ending September 30, 2027.[2]

[1] UGI Gas Statement No. 2, p. 2.
[2] UGI Gas Statement No. 1, pp. 5–6.

FPFTY REPORTING REQUIREMENTS

Q. DID THE COMPANY PROVIDE A SCHEDULE SHOWING PLANT ADDITIONS AND RETIREMENTS THAT SUPPORT THE PROJECTED LEVEL OF TOTAL PLANT IN THE FPFTY?

A. Yes. The Company provided UGI Exhibit A – FPFTY, Schedule C-2 and UGI Exhibit A - FTY, Schedule C-2 showing account details for the plant additions and retirements totaling $6,208,881,000 and $6,676,559,000 for the FTY and FPFTY, respectively.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT UGI GAS PROJECTS TO BE IN SERVICE DURING THE FTY ENDING SEPTEMBER 30, 2026 AND THE FPFTY ENDING SEPTEMBER 30, 2027?

A. Yes. I recommend that the Company be required to provide I&E, the Office of Consumer Advocate (OCA), and the Office of Small Business Advocate (OSBA) with an update to UGI Exhibit A - FTY, Schedule C-2 no later than February 1, 2027, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending September 30, 2026. An additional update to UGI Exhibit A - FPFTY, Schedule C-2 should be provided for actuals through September 30, 2027, no later than February 1, 2028.

Q. WHY DO YOU RECOMMEND THAT UGI GAS PROVIDE THESE UPDATES?

A. There is value in determining how closely UGI Gas' projected investments in future plant comport with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between UGI Gas' projected and actual results will help inform the Commission and the parties in UGI Gas' future rate cases as to the validity of UGI Gas' projections. Having the Company provide this information is necessary for parties and the Commission to evaluate the Company's abilities to accurately forecast its FPFTY plant additions.

By using an FPFTY, UGI Gas is requesting that ratepayers pre-pay a return on its projected investment in future facilities that are not in place and providing service at the time the new rates take effect but also are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investments correspond with FPFTY projections used in setting rates provides the Commission with actual data to gauge the accuracy of UGI Gas' projected investments in future proceedings.

PRESENT RATE REVENUE

Q. WHAT AMOUNT OF PRESENT RATE REVENUE IS THE COMPANY CLAIMING FOR THE FPFTY ENDING SEPTEMBER 30, 2027?

A. UGI Gas is claiming $1,234,682,277[3] in present rate revenue including gas costs, surcharges, and other operating revenues.

Q. DO YOU AGREE WITH THE FPFTY CLAIMED PRESENT RATE REVENUE OF $1,234,682,277?

A. No. As described below, UGI Gas has understated its present rate revenue for the FPFTY, and I am recommending an increase of $464,481 in present rate revenues from $1,234,682,277 to $1,235,146,758. My recommendation is based on adjustments to UGI Gas' claimed $794,637,988[4] of residential present rate revenue in the FPFTY as discussed below.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ADJUSTMENT TO UGI'S PRESENT RATE REVENUE CLAIM FOR THE FPFTY?

A. My recommendation is based on a change to the rate class R/RT heating customer usage decline reflected in the FPFTY that was projected beyond the end of the FPFTY.

[3] UGI Book V, Exhibit E, p. 1.
[4] UGI Book V, Exhibit E, p. 1.

R/RT HEATING CUSTOMER USAGE DECLINE

Q. WHAT IS THE COMPANY'S CLAIM REGARDING R/RT HEATING CUSTOMER USAGE?

A. UGI projected that R/RT heating customer usage is declining and its usage per customer projections included a reduction to account for conservation items and measures including, but not limited to, regular and accelerated appliance replacements, high efficiency appliance installations, setback thermostat installations, modifications to new and existing buildings that are designed to decrease energy consumption, and changes in consumer behavior in response to energy price changes, and other economic influences.[5]

Q. WHAT AVERAGE USAGE PER R/RT HEATING CUSTOMER IS THE COMPANY PROJECTING?

A. The Company's projected annual usage in the FPFTY for R/RT heating customers is approximately 82.35 Mcf per customer.[6]

Q. HOW DID UGI GAS PROJECT THAT R/RT HEATING CUSTOMERS WOULD USE 82.35 MCF PER YEAR?

A. The Company performed a regression analysis of actual usage, degree day, lagged heating degree days, and the weighted trend data for the period October 2003

[5] UGI Gas Statement No. 10, pp. 8-9.
[6] UGI Book II, Attachment SDR-RR-11(a), p. 8.

through September 2025.[7] The Company then used the results of the regression analysis to project the usage decline per month through the FTY, the FPFTY, and through March 2028, which is six months past the end of the FPFTY with the final result being the projected 82.35 Mcf per customer. UGI Gas also projected its commercial usage through March 2028,[8] but that projection did not result in any change from the year ending September 30, 2027. Therefore, my discussion will focus on R/RT heating customers.

Q. DO YOU AGREE WITH THE COMPANY'S PROJECTED USAGE PER R/RT HEATING CUSTOMER?

A. No. Based on my analysis, the Company has understated its projected usage per customer for R/RT heating customers.

Q. WHY HAVE YOU CONCLUDED THE PROJECTED USAGE PER CUSTOMER FOR R/RT HEATING CUSTOMERS IS UNDERSTATED?

A. My disagreement with the Company's determination of average usage per customer concerns the inclusion of usage decline beyond the end of the FPFTY to project the average usage per R/RT heating customer in the FPFTY. The FPFTY ends on September 30, 2027; however, the Company's analysis projects residential

[7] UGI Book II, Attachment SDR-RR-11(a).
[8] UGI Book II, Attachment SDR-RR-11(b), p. 6.

heating customer usage declines through March 2028, which is six months beyond the FPFTY.

Q. DID THE COMPANY EXPLAIN WHY IT EXTENDED THE DECLINE IN USAGE BEYOND THE END OF THE FPFTY?

A. In response to I&E-RS-12, the Company provided an example of an assumed 12-month history of an individual customer replacing existing 80% efficient heating equipment with a new 95% heating system in July of 2027. According to the Company, this hypothetical situation would result in the customer no longer being able to meet its projected usage per customer (UPC) in the 2027-2028 heating period. Instead, the Company proposed using a midpoint convention to capture this new, lower usage resulting from an installation prior to the end of the FPFTY.[9]

Q. IS THE USE OF A MID-YEAR CONVENTION APPROPRIATE?

A. No. The Company has selectively used a mid-year convention to make a projection that extends beyond the end of the FPFTY for usage decline when all other financial criteria are based on the end of the FPFTY. This inappropriately misaligns data for determining a revenue requirement and affords the Company a

[9] I&E Exhibit No. 4, Schedule 1, p. 2.

greater revenue increase than is appropriate for its FPFTY claim. The impact of this discrepancy is further explained below.

Q. IS THERE ANY BASIS FOR PROJECTING USAGE BEYOND THE END OF THE FPFTY?

A. No. The Company selected September 30, 2027, as the end of the FPFTY, and there is no basis for projecting usage six months beyond the end of the FPFTY. The test year period is meant to be a snapshot look at one year of a utility's revenue requirement such that all inputs into the ratemaking equation, i.e., rate base, depreciation, revenues, expenses, taxes, and rate of return are determined using the same period. Therefore, the average usage per R/RT heating customer that is used to determine revenue should be determined consistently with the end of the FPFTY time period. For example, the Company based its projected customer count on the end of the FPFTY; therefore, it is improper to base the usage per R/RT heating customer on the projected average usage per customer six months past the end of the FPFTY as a different customer count would be applicable to that time period. The proposed mismatch in the usage per customer conflicts with all other ratemaking inputs. Furthermore, the end date of the FPFTY is under the control of the Company. If the Company wishes to ensure the changes in UPC for the 2027-2028 heating period were included in its projections, it could have selected, for example, an FPFTY ending April or May 2028. This

way, the changes to conservation would be included in the projection and all of the inputs into the ratemaking equation would remain aligned.

Q. WILL THE USE OF "ANNUALIZED" USE PER CUSTOMER DATA BENEFIT THE COMPANY THROUGH INCREASED REVENUES?

A. Yes. If permitted to use mid-period annualization, the Company would receive additional revenue during the FPFTY. This additional revenue would be the result of deducting the usage of R/RT heating customers that are projected to use less gas after the end of the FPFTY before these customers use less gas. The Company's example of a customer who installs new efficient heating equipment reveals a fundamental misunderstanding of ratemaking using the FPFTY. As described above, a test year is a snapshot look at a single year of a utility's revenue requirement. Specifically, an FPFTY is a snapshot look at the revenue requirement for the year directly after the Company's rates go into effect. Thus, the UPC projection for the customer who installs higher efficiency heating equipment in July 2027 was correct for the 2026-2027 heating season, the period for which the Company's proposed rates are designed. It is not reasonable to implement rates based on projections for two heating seasons after those rates go into effect.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS CONCERNING THE COMPANY'S "ANNUALIZATION" OF POST-FPFTY USAGE DECLINES.

A. The usage decline beyond the end of the FPFTY should be rejected. There is no justification for allowing the level of usage projected at the end of the FPFTY to be "annualized" by projecting out to March 2028. The inclusion of such an "annualization" will benefit the Company to the detriment of customers.

Q. WHAT IS THE CHANGE TO AVERAGE USAGE PER R/RT CUSTOMER THAT WOULD BE REQUIRED TO ELIMINATE THE INCLUSION OF ANY POST-FPFTY DECLINE?

A. The average usage per R/RT customer would need to be increased by 0.12 Mcf per customer per year to eliminate the inclusion of any post-FPFTY UPC decline. This 0.12 Mcf per customer per year was determined by calculating the difference between the 82.47 Mcf per customer at the end of the FPFTY and the 82.35 Mcf per customer as of March 2028.[10]

[10] UGI Book II, Attachment SDR-RR-11(a), p. 8.

Q. HOW MUCH DO GAS VOLUMES INCREASE IF THE AVERAGE USAGE PER R/RT CUSTOMER IS INCREASED BY 0.12 MCF PER CUSTOMER PER YEAR?

A. To account for the increase in average UPC, gas volumes would increase by 73,358 Mcf. This 73,358 Mcf of gas was determined by multiplying 0.12 Mcf per customer per year by 611,318 R/RT heating customers.[11]

Q. HOW MUCH DOES PRESENT RATE USAGE REVENUE INCREASE IF THE AVERAGE USAGE PER R/RT HEATING CUSTOMER IS INCREASED BY 0.12 MCF PER CUSTOMER PER YEAR?

A. At FPFTY year-end usage, present rate usage revenue increases by $464,481. This $464,481 of present rate R/RT revenue was determined by multiplying the 73,358 Mcf of gas described above times the present usage rate of $6.3317 per Mcf.[12]

Q. IF R/RT PRESENT USAGE RATE REVENUE IS INCREASED BY $464,481, SHOULD THERE BE A CORRESPONDING INCREASE IN PURCHASED GAS REVENUE AND EXPENSES?

A. Yes. An increase in R/RT present usage rate revenue will result in an increase to purchased gas revenue. However, the increase to purchased gas revenue would be

[11] UGI Book III, Exhibit SAE-7(a).
[12] UGI Book V, Exhibit E, p. 2 and I&E Exhibit No. 3, Schedule. 2, line 9.

offset by purchased gas expenses. Therefore, I have not included the increase to purchased gas revenue in my present rate revenue calculation.

Q. WHAT IS THE TOTAL INCREASE IN RESIDENTIAL PRESENT RATE REVENUE WITH YOUR RECOMMENDED 73,358 MCF POST-FPFTY UPC ADJUSTMENT?

A. Present rate revenue increases by $464,481 from $794,637,988 to $795,102,469.

WEATHER NORMALIZATION ADJUSTMENT

Q. WHAT IS A WEATHER NORMALIZATION ADJUSTMENT?

A. A WNA mechanism adjusts a customer's bill to correct for variations from normal weather in order to have the bill reflect normal weather conditions through credits and surcharges for colder than normal and warmer than normal weather, respectively.

Q. DOES UGI GAS CURRENTLY HAVE A WNA IN EFFECT?

A. Yes. The Company currently has a WNA pilot program in effect that is set to expire in October 2027.[13]

[13] UGI Gas Statement No. 11, p. 32.

Q. WHAT IS UGI GAS PROPOSING REGARDING ITS WNA?

A. UGI Gas is proposing to extend its WNA pilot program for an additional five years which functions as follows: (1) it adjusts customer bills based on comparing actual Heating Degree Days (HDDs) to normal HDDs based on a 10-year weather history;[14] (2) it includes a 3% deadband; (3) it applies to residential (excluding CAP customers) and small commercial class customers; and (4) it applies during the months of October through April.[15]

Q. ARE YOU RECOMMENDING ANY CHANGES TO THE WNA PILOT AS PROPOSED BY THE COMPANY?

A. Yes. While I am not opposed to extending the WNA pilot for an additional five years, I am recommending that the 3% deadband be increased to 5% consistent with the Commission's Order in the recent Columbia Gas of Pennsylvania, Inc. (Columbia) base rate case.[16]

Q. WHAT IS A DEADBAND?

A. A deadband is a threshold of Normal Heating Degree Days where the WNA adjustment is not triggered.

[14] UGI Gas Statement No. 11, pp. 40-41.
[15] UGI Gas Statement No. 11, p. 35.
[16] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, pp. 301-02 (Order Entered December 4, 2025).

Q. WHAT ARE YOU RECOMMENDING REGARDING A DEADBAND IN THE COMPANY'S WNA?

A. I am recommending the deadband be increased from the existing 3% to 5%.

Q. WHY ARE YOU RECOMMENDING THE DEADBAND BE INCREASED TO 5%?

A. I am recommending the deadband be increased to 5% because this percentage more adequately captures what could be considered normal weather fluctuations in Pennsylvania and places more of the burden for weather variation back onto the Company as a normal part of doing business.

Q. IS YOUR RECOMMENDATION SUPPORTED BY RECENT COMMISSION PRECEDENT?

A. Yes. In its recent decision in the Columbia base rate case, the Commission determined that a 5% deadband is reasonable.[17] My recommendation is consistent with the Commission's decision in the Columbia base rate case.

[17] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, pp. 301-02 (Order Entered December 4, 2025).

SCALE BACK OF RATES

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED INCREASE BY CLASS.

A. The Company proposed R/RT revenue increase by $74,675,276, N/NT revenue - increase by $23,385,309, DS revenue by $708,849, LFD revenue increase by $735,978, XD-Firm revenue decrease by $64,353, and Interruptible revenue decrease by $73,315.[18] The revenue decrease for the XD-Firm and Interruptible classes represents the Distribution System Improvement Charge (DSIC) being set to zero, the customer charges and usage rates for those classes do not have any changes being proposed.[19]

Q. WHAT IS A SCALE BACK OF RATES?

A. If the Commission grants an increase less than the amount UGI Gas requested, the Company's proposed rates would be reduced, or scaled back, to produce the revenue requirement allowed by the Commission.

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND FOR THE R/RT, N/NT, DS, AND LFD CLASSES?

A. I recommend that the customer charge and usage rates that are proposed to increase be scaled back such that increases for each customer class are scaled back

[18] UGI Gas Book V, Exhibit E, p. 1.
[19] UGI Gas Book V, Exhibit E, pp. 6-7.

proportionally to the increase originally proposed by UGI Gas based on the cost of service study that is ultimately approved by the Commission.

Q. WHY DO YOU RECOMMEND THAT CUSTOMER CHARGES BE INCLUDED IN ANY SCALE BACK?

A. I recommend that customer charges be included in any scale back because it is consistent with Commission precedent. In the 2025 Columbia Gas of Pennsylvania, Inc. base rate case, the Commission determined that despite a reduction to the customer charge, it should be included in the scale back of rates.[20]

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND FOR THE XD AND INTERRUPTIBLE CLASSES?

A. The customer charges and usage rates were not increased under proposed rates, so they should not be included in any scale back.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[20] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, pp. 280-3 (Order Entered December 4, 2025).

ETHAN H. CLINE

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present

Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008

Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008

J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007

CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL
- Attended Society of Depreciation Professionals Annual Conference and Training, 2017, 2018, and 2019

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. AQUA Clarion Wastewater Operations, Docket No. R-2010-2166208
6. AQUA Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103

9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Peoples Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition, Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172
37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934
40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209
44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638

51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296
57. Columbia Gas of Pennsylvania, Inc., Docket No. R-2018-2647577
58. Duquesne Light Company, Docket No. R-2018-3000124
59. Suez Water Pennsylvania, Inc., Docket No. R-2018-3000834
60. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the Township of Sadsbury, Docket No. A-2018-3002437
61. The York Water Company, Docket No. R-2018-3000006
62. Application of SUEZ Water Pennsylvania, Inc. Acquisition of the Water and Wastewater Assets of Mahoning Township, Docket Nos. A-2018-3003517 and A-2018-3003519
63. Pittsburgh Water and Sewer Authority, Docket Nos. R-2018-3002645 and R-2018-3002647
64. Joint Application of Aqua America, Inc. et al., Acquisition of Peoples Natural Gas Company LLC, et al., Docket Nos. A-2018-3006061, A-2018-3006062, and A-2018-3006063
65. Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority, Docket Nos. M-2018-2640802 and M-2018-2640803
66. Philadelphia Gas Works 1307(f), Docket No. R-2019-3007636
67. People Natural Gas Company, LLC, Docket No. R-2018-3006818
68. Application of Pennsylvania American Water Company Acquisition of the Steelton Borough Authority, Docket No. A-2019-3006880
69. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the Township of Cheltenham, Docket No. A-2019-3006880
70. Philadelphia Gas Works, Docket No. R-2019-3009016
71. Wellsboro Electric Company, Docket No. R-2019-3008208
72. Valley Energy, Inc., Docket No. R-2019-3008209
73. Citizens' Electric Company of Lewisburg, Pa, Docket Non. R-2019-3008212
74. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the East Norriton Township, Docket No. A-2019-3009052
75. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2020-3017850
76. Peoples Gas Company, LLC 1307(f), Docket No. R-2020-3017846
77. Philadelphia Gas Works, Docket No. R-2020-3017206
78. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 et al.
79. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835
80. Pennsylvania America Water Company, Docket Nos. R-2020-3019369 and R-2020-3019371
81. PECO Energy Company – Gas Division, Docket No. R-2020-3019829
82. PGW 1307(f), Docket No. R-2021-3023970

83. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2021-3023965
84. Peoples Gas Company, LLC 1307(f), Docket No. R-2021-3023967
85. UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618
86. Columbia Gas of Pennsylvania, Inc., Docket No. R-2021-3024926
87. Duquesne Light Company, Docket No. R-2021-3024750
88. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2021-3025652
89. Pittsburgh Water and Sewer Authority, Docket Nos. R-2021-3024773 et al.
90. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Lower Makefield Township, Docket No. A-2021-3024267
91. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385 and R-2021-3027386
92. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the York City Sewer Authority, Docket No. A-2021-3024681
93. City of Lancaster – Bureau of Water, Docket No. R-2021-3026682
94. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of East Whiteland Township, Docket No. A-2021-30246132
95. UGI Utilities, Inc. – Gas Division, Docket No. R-2021-3030218
96. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2022-3030661
97. Columbia Gas of Pennsylvania, Inc., Docket No. R-2022-3031211
98. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2022-3032242
99. Pennsylvania American Water Company, Docket Nos. R-2022-3031672 and R-2022-3031673
100. The York Water Company, Docket Nos. R-2022-3031340 and R-2022-3032806
101. Columbia Gas of Pennsylvania, Inc., Docket No. R-2022-3032167
102. National Fuel Gas Distribution Corporation, Docket No. R-2022-3035730
103. UGI Utilities, Inc. – Electric Division, Docket No. R-2022-3037368
104. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the Butler Area Sewer Authority, Docket No. A-2022-3037047
105. Philadelphia Gas Works, Docket No. R-2023-3037933
106. Pittsburgh Water and Sewer Authority, Docket Nos. R-2023-3039920 et al.
107. Pennsylvania-American Water Company, Docket Nos. R-2023-3043189 and R-2023-3043190
108. Peoples Natural Gas Company, LLC, Docket No. R-2023-3044549
109. Duquesne Light Company, Docket No. R-2024-3046523
110. PECO Energy Company – Gas Division, Docket No. R-2024-3046932
111. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2024-3047822 and R-2024-3047824
112. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Beaver Falls, Docket No. A-202-3033138
113. Pike County Light and Power Company (Gas), Docket No. R-2024-3052357
114. UGI Utilities, Inc. – Gas Division, Docket No. R-2024-3052716
115. Philadelphia Gas Works, Docket No. R-2025-3053112
116. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2025-3054394

117. Wellsboro Electric Company, Docket No. R-2025-3054392
118. Pittsburgh Water and Sewer Authority, Docket No. R-2025-3055010, R-2025-3055011, and R-2025-3055012
119. Section 529 Investigation of Rock Spring Water Company, Docket No. P-2024-3051313
120. Energy Center Harrisburg LLC, Docket. No. R-2025-3055959
121. PPL Electric Utilities Corporation, Docket No. R-2025-3057164
122. Pennsylvania-American Water Company, Docket Nos. R-2025-3057983 and R-2025-3058051
123. Section 529 Investigation of Conneaut Lake Park Water Corporation, Inc., Docket Nos. P-2024-3051855 and I-2024-3051857

I&E Exhibit No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Exhibit to Accompany

the

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Test Year
Reporting Requirements
Present Rate Revenue
Weather Normalization Adjustment
Scale Back of Rates

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RS-11 thru RS-12)
Delivered on March 19, 2026

I&E-RS-11

Request:

Reference UGI SDR-RR-11(a), p. 8 as of September 2027 showing 82.47 Mcf labeled "FY 27":

A. Explain whether the 82.47 Mcf represents the normal annualized usage of a customer on September 30, 2027, or some other period of time.

B. Explain whether the 82.47 Mcf represents the average normal annualized usage for the twelve months ending September 30, 2027, or some other period of time.

Response:

A & B. Pursuant to the mid-point methodology explained in the response to I&E-RS-12, the 82.47 Mcf value would represent the annualized normalized value of UPC for the period ending March 31, 2027.

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

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RS-11 thru RS-12)
Delivered on March 19, 2026

I&E-RS-12

Request:

Reference UGI SDR-RR-11(a), p. 8 as of March 2028 showing 82.35 Mcf labeled "FPFTY annualized FY 27":

A. Explain whether the 82.35 Mcf represents the normal annualized usage of a customer on March 31, 2028, or some other period of time.

B. Explain whether the 82.35 Mcf represents the average normal annualized usage for the twelve months ending March 31, 2028, or some other period of time.

Response:

A. The 82.35 Mcf value found on page 8 of Attachment SDR-RR-11(a) noted as "Fully Projected Future Test Year Annualized FY 27" represents the normal annualized residential heating Use Per Customer (UPC) value as of the end of the FPFTY period, or as of September 30, 2027. While this value represents the sum of monthly UPC values for the 12 month period ending March 31, 2028, it is to be interpreted utilizing a mid-period convention across a summation of 12 individual months of values. Thus, the 12 months ending March 31, 2028 have a mid-point of September 30, 2027, and that is the accurate annualized normalized value as of September 30, 2027 (the end of the FPFTY).

A single customer example will help demonstrate this mid-point convention use in calculating UPC. For example, assume the 12-month history of an individual customer's actual gas usage for a twelve month period ending on September 30, 2027, totals 85 Mcf and is reflective of the customer's usage of their then-existing 80% efficient heating equipment during the 2026-2027 heating season (the season ending March of 2027). If that customer installs a new, 95% efficient heating system in July of 2027, the customer's annual projected usage will drop to 71.5 Mcf per year as of the day the new system is installed in July. (85 Mcf use x 0.80 old furnace efficiency = 68 Mcf heat requirement; 68 Mcf heat requirement/0.95 new furnace efficiency = 71.5 Mcf use). Utilizing the customer's use of 85 Mcf (12 month ending September 30, 2027) would yield an incorrect value of anticipated annualized normalized use as of September 30, 2027. The new furnace has already been installed and the home is no longer capable of utilizing an annualized and normalized consumption of 85 Mcf; it is now 71.5 Mcf. The Company's mid-point convention method captures this new, lower usage resulting

UGI Utilities, Inc. - Gas Division
Docket No. R-2025-3059523
UGI Gas 2026 Base Rate Case
Responses to I&E (RS-11 thru RS-12)
Delivered on March 19, 2026

I&E-RS-12 (Continued)

from an installation prior to the end of the FPFTY and is appropriate to include as the annualized normalized UPC value (usage for 12 month ending March 31, 2028, the end of the heating season, would total 71.5 Mcf with the new furnace).

B. Please see the response to A above.

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

UGI Utilities, Inc. - Gas Division
Residential Service - Rate Schedules R & RT
Calculation of the Effect of Proposed Rates
12-Months Ending September 30, 2027

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue (4)	Proposed Rate (5)	Proposed Revenue (6)	Proposed Revenue Change (7)	% Change (8)
Customer Charges	7,611,024		$ 16.25	$ 123,679,140	$ 23.00	$ 175,053,552	$ 51,374,412	
Distribution Charges		50,491,037	$ 6.3317	$ 319,694,099	$ 6.8383	$ 345,272,858	$ 25,578,759	
State Tax Adjustment Surcharge (STAS) - Rider A			0.01%	$ 79,456	0.00%	$ -	$ (79,456)	
Purchased Gas Costs (PGC) - Rider B		44,265,497	$ 6.7486	$ 298,730,133	$ 6.7486	$ 298,730,133	$ -	
Merchant Function Charge (MFC) - Rider D		44,265,497	2.56%	$ 7,647,491	2.37%	$ 7,079,904	$ (567,587)	
Gas Procurement Charge (GPC) - Rider E		44,265,497	$ 0.0660	$ 2,921,523	$ 0.0660	$ 2,921,523	$ -	
Universal Service Program (USP) - Rider F		47,870,552	$ 0.6363	$ 30,460,032	$ 0.6363	$ 30,460,032	$ -	
Energy Efficiency & Conservation Rider (EEC) - Rider G		50,491,037	$ 0.1940	$ 9,795,261	$ 0.1940	$ 9,795,261	$ -	
Distribution System Improvement Charge (DSIC) - Rider I			0.33%	$ 1,630,852	0.00%	$ -	$ (1,630,852)	
Total - Rates R/RT	**7,611,024**	**50,491,037**		**$ 794,637,988**		**$ 869,313,264**	**$ 74,675,276**	**9.4%**

I&E Adjustemnts to remove post FPFTY UPC

Description	Number of Bills (1)	Pro Forma Consumption Mcf (2)	Current Rate (3)	Current Revenue Adjustment (4)	Current Revenue (5)	Adjusted Usage Current Revenue (6)
Customer Charges	7,611,024		$ 16.25	$ 123,679,140	$ 123,679,140	$ 123,679,140
Distribution Charges		73,358	$ 6.3317	$ 464,481	$ 319,694,099	$ 320,158,580
Total - Rates R/RT	**7,611,024**	**73,358**		**$ 124,143,621**	**$ 443,373,239**	**$ 443,837,720**

I&E Exhibit No. 3
Schedule 2

I&E Statement No. 4
Witness: Anna L. Ritchie

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Direct Testimony

of

Anna L. Ritchie

Bureau of Investigation and Enforcement

Concerning:

METHANE DETECTOR PILOT PROGRAM
PIPELINE REPLACEMENT COSTS

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Anna L. Ritchie. I am a Civil Engineer in the Pipeline Safety Division of the Pennsylvania Public Utility Commission's (Commission) Bureau of Investigation and Enforcement (I&E). My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT EXPERIENCE?

A. An outline of my education and employment history is attached as Appendix A.

Q. WHAT ARE YOUR MAJOR DUTIES AS AN ENGINEER IN THE PIPELINE SAFETY DIVISION?

A. My major duties include the inspection of natural gas infrastructure, including pipeline operation, construction, and maintenance, to ensure compliance with the Pipeline and Hazardous Materials Safety Administration's (PHMSA) federal safety regulations, and the Commission's applicable regulations, including Title 52, Chapter 59 of the Pennsylvania Code. On average, I conduct over 85 inspections per year.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address the federal regulations UGI

Utilities, Inc. – Gas Division's (UGI Gas or Company) is required to follow and to evaluate the effectiveness of UGI Gas' mitigation of known risks within its system. My direct testimony addresses the following issues:

1. Methane Detectors
2. Restoration Costs

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 4 contains schedules that support my direct testimony.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires a balance between the interests of ratepayers, the regulated utility, and the regulated community.

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF UGI WITNESS JILL E. WALTERS AS IT RELATES TO UGI'S GAS SAFETY AND OPERATIONS?

A. Yes. I have reviewed Ms. Walter's direct testimony.[1] Ms. Walter addresses: (1) natural gas operations; (2) regulatory compliance; (3) system safety and reliability; (4) leak reductions and emergency response; (5) safety and training initiatives; and

[1] UGI Gas Statement No. 3.

(6) environmental programs.

Q. WHAT FEDERAL AND STATE REGULATIONS CONTROL UGI GAS' PIPELINE REPLACEMENT?

A. UGI Gas is mandated to implement a Distribution Integrity Management Program (DIMP) under Title 49, Subpart P §§ 192.1001-1015 of the Code of Federal Regulations. Additionally, utilities that seek to continue a previously approved Distribution System Improvement Charge (DSIC) mechanism are required to submit a Long-Term Infrastructure Improvement Plan (LTIIP) pursuant to 52 Pa. Code §121.1 and §121.3.

Q. WHY MUST A NATURAL GAS DISTRIBUTION COMPANY COMPLY WITH THE DIMP REGULATIONS?

A. PHMSA created the DIMP regulations to reduce the number of U.S. Department of Transportation (U.S. DOT) Reportable Incidents.[2] DIMP is a performance-

[2] Under 49 CFR § 191.3, a PHMSA Reportable Incident is defined as any of the following events:
(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
(i) A death, or personal injury necessitating in-patient hospitalization;
(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.
(iii) Unintentional estimated gas loss of three million cubic feet or more.
(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.
(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

based regulatory program required of gas distribution operators and is driven by risk management.

Q. WHY MUST A NATURAL GAS DISTRIBUTION COMPANY FILE AN LTIIP?

A. A natural gas distribution company must submit an LTIIP for Commission approval to be eligible to recover the reasonable and prudently incurred costs related to the repair, improvement, and replacement of eligible property through the DSIC. The LTIIP is intended to address the planned acceleration of the replacement of aging infrastructure by the utility and be sufficient to ensure and maintain adequate, efficient, safe, reliable, and reasonable service to customers.[3]

Q. WHAT ARE THE REQUIREMENTS OF A DIMP?

A. DIMP requires gas distribution pipeline operators to:

1. Demonstrate knowledge of the gas distribution system;
2. Identify threats;
3. Evaluate and rank risks;
4. Identify and implement measures to address risk;
5. Measure performance, monitor results, and evaluate effectiveness;
6. Evaluate and improve the DIMP; and
7. Report results.[4]

[3] See 52 Pa. Code § 121.1.
[4] See 49 CFR § 192.1007.

DIMP requirements include the identification of threats to pipeline facilities and the requirement for operators to create plans to mitigate and reduce the risks caused by those threats. UGI Gas uses a risk-based prioritization process to select pipelines for replacement. UGI Gas determines pipeline replacements by managing the risk ranking of the different aspects of the pipeline and then replacing the pipe based on the highest risk ranking.

Q. WHAT ARE THE REQUIREMENTS OF AN LTIIP?

A. The LTIIP must include the following elements:

1. Identification of types and age of eligible property owned and operated by the utility for which it is seeking DSIC recovery.
2. An initial schedule for planned repair and replacement of eligible property.
3. A general description of location of eligible property.
4. A reasonable estimate of quantity of eligible property to be improved or repaired.
5. Projected annual expenditures and means to finance the expenditures.
6. A description of the manner in which infrastructure replacement will be accelerated and how repair, improvement, or replacement will ensure and maintain adequate, efficient, safe, reliable, and reasonable service to customers.

7. A workforce management and training program designed to ensure that the utility will have access to a qualified workforce to perform work in a cost-effective, safe, and reliable manner.

8. A description of a utility's outreach and coordination activities with other utilities, Department of Transportation and local governments regarding the planned maintenance/construction projects and roadways that may be impacted by the LTIIP.

The LTIIP must address only the specific property eligible for DSIC recovery.[5]

Q. WHAT ARE THE COMMON MITIGATION MEASURES FOR HIGH-RISK PIPELINE SEGMENTS?

A. The industry's common mitigation measure to reduce pipeline risk is to replace the highest risk pipelines first. As a company replaces the pipelines calculated to represent the highest risk, the total system risk should be reduced. The overall risk of the asset group will be reduced as the riskiest pipeline is replaced if enough pipe is replaced in that asset group annually to overcome the increasing risks on other segments within that group.

Q. SHOULD PIPELINE REPLACEMENT MITIGATION MEASURES BE BASED ON THE LTIIP OR THE DIMP?

A. Pipeline replacement, which includes high risk cast iron and bare steel, should be

[5] See 52 Pa. Code § 121.3.

based on the DIMP. The LTIIP is a forward-looking plan for the replacement of DSIC-eligible assets. Overall, pipeline replacement should be risk based and, thus, driven by the DIMP.

METHANE DETECTORS

Q. HOW HAS UGI GAS' AMBASSADOR PROGRAM FOR THE METHANE DETECTOR PROGRAM PROGRESSED?

A. Since February 2026, UGI Gas has placed over 200 Smart Remote Methane Detectors (SRMDs) in the homes of UGI employees who are also UGI Gas customers. These employees are ambassadors of the natural gas detector program. Ambassadors are to advocate gas safety to their friends and family.[6]

Q. WHAT CONSIDERATIONS ARE TAKEN INTO ACCOUNT WHEN SELECTING A CUSTOMER FOR THE NATURAL GAS DETECTOR PROGRAM?

A. UGI Gas looks at which customers recently had a natural gas leak, an odor complaint, or if the customer has an inside meter. UGI Gas has not implemented this program with public customers.[7]

[6] I&E Exhibit No. 4, Schedule 1.
[7] I&E Exhibit No. 4, Schedule 1.

Q. HOW ARE CUSTOMERS NOTIFIED OF THE NATURAL GAS DETECTOR PROGRAM?

A. UGI Gas sent out a targeted marketing letter campaign to customers who have recently had an inside odor complaint and a positive gas indication when a UGI technician responded. Through the letter campaign, UGI Gas has reached out to 1,355 customers: 228 requests were made for methane detectors and UGI Gas has sent out 212 units as of March 13, 2026. UGI Gas also has a company website dedicated to education of the detectors, third-party storefronts to purchase a detector, educational materials sent via mail with the scratch and sniff flyers, and a customer newsletter.[8]

Q. HAVE FEDERAL AGENCIES PROVIDED SUPPORT FOR THE INSTALLATION OF INDOOR METHANE DETECTORS?

A. Yes. Both PHMSA and the National Transportation and Safety Board (NTSB) have provided written support for the installation of indoor methane detectors or alarms. Dating back to 2012, PHMSA provided a statement in Advisory Bulletin 2012-05, largely regarding Pennsylvania incidents stemming from cast iron main failures, asking owners and operators of cast iron distribution pipelines and state pipeline safety representatives to consider, among other items, the installation of interior/home methane gas alarms.[9] The NTSB has repeatedly encouraged the

[8] I&E Exhibit No. 4, Schedule No. 1.

[9] See Federal Register, Vol. 77, No. 57 (March 23, 2012), https://www.govinfo.gov/content/pkg/FR-2012-03-23/pdf/2012-7080.pdf.

installation of these indoor methane detector devices in final pipeline investigation reports (PIR), including but is not limited to, the recent NTSB West Reading Chocolate Factory[10] and Atmos Energy Corporation[11] investigations.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE CONTINUED IMPLEMENTATION OF METHANE DETECTORS IN UGI GAS' SYSTEM?

A. Yes. I recommend that UGI Gas continue to expand the SRMD pilot program by identifying areas that are prone to leaks, high risk pipeline areas, buildings or homes, businesses, and places of congregation with inside meter sets and regulators to place these methane detector units within these higher risk areas first. In order to effectuate the expansion of the pilot program, I recommend that the pilot program be increased to require installation of 3,000 SRMD units during the pilot timeframe. Further, I recommend that UGI Gas is expected to continue to expand the methane detector program until every gas customer has an SRMD unit.

Q. DO YOU HAVE A RECOMMENDATION REGARDING REPORTING REQUIREMENTS FOR THE METHANE DETECTOR PROGRAM?

A. Yes. I recommend that UGI Gas file quarterly reports with the Commission under this docket number, within 30 days of the end of each calendar quarter, beginning with the calendar quarter that ends December 31, 2026, and ending with the

[10] See NTSB PIR-25-01 UGI Explosion and Fire.
[11] See NTSB PIR-26-01 Atmos Explosion and Fire.

calendar quarter that ends December 31, 2031, or when otherwise directed by the Commission. Each report shall include, separately, details for Remote Methane Detectors (RMDs) and SRMDs, as follows:

- The number of RMDs and SRMDs funded in the subject calendar quarter;
- The number of RMDs and SRMDs distributed in the subject calendar quarter;
- The total number of residences, businesses, and places of congregation where methane detectors are distributed under the program to date; and
- A detailed summary of expenses incurred, broken out in sufficient detail to identify:
  - The number of detectors installed;
  - The cost of the detectors and installation, broken down by detector, materials, and labor;
  - Any costs incurred for monitoring; and
  - Outreach and education costs.
- A detailed summary of meter incidences occurring in the quarter, detailed as follows:
  - Leaks detected by the installed detectors;
  - The resolution of that leak detection; and
  - Any reported detector failure incidents.

To capture the information consistently, UGI Gas shall complete the Methane Detector Reporting Excel spreadsheet, which has been submitted alongside my testimony labeled as I&E Exhibit No. 5, Schedule 4,[12] provided by the Commission, each calendar quarter, beginning with the calendar quarter that ends December 31, 2026.

RESTORATION COSTS

Q. WHAT IS INCLUDED IN UGI GAS' PIPELINE REPLACEMENT COSTS?

A. UGI Gas' capital costs include Contractor, Material, Other, Restoration, Labor, Equipment, and Overhead. In response to I&E-PS-18, UGI Gas provided a table that demonstrated cost breakdown for pipeline replacement from 2015 to 2025.[13]

Q. ON AVERAGE, ARE THE PIPELINE REPLACEMENT COSTS INCREASING OVER TIME?

A. Yes. UGI Gas' pipeline annual replacement costs have been increasing on average since 2020, however, its cost for 2025 has decreased by almost 41% when compared to 2024. Performing an analysis of six years of cost data provided by the Company, the total pipeline replacement cost from 2020 to 2025 increased from $1,373,414 per mile to $2,621,549 per mile, which is a 91% increase in total cost. Within UGI Gas' total pipeline replacement cost per mile, restoration costs from 2020 to 2025 increased from $312,906 per mile to $460,623 per mile, which

[12] I&E Exhibit No. 4, Schedule No. 4.
[13] I&E Exhibit No. 4, Schedule No. 3.

is a 47% increase in restoration costs during the last six years.[14]

Table 1

Pipeline Miles Replaced, Restoration & Total Cost per Mile

Year	Miles Replaced	Restoration Cost per Mile	Total Cost per Mile	Increase in Restoration Costs (%)
2020	60	$312,906	$1,373,414	
2021	101	$319,069	$1,301,351	1.97%
2022	73	$560,054	$2,535,485	75.53%
2023	54	$711,835	$3,322,251	27.10%
2024	44	$780,386	$3,494,434	9.63%
2025	67	$460,623	$2,621,549	-40.98%

Q. DOES THE TOTAL COST FOR PIPELINE REPLACEMENT INCLUDE THE COSTS ASSOCIATED WITH SERVICE LINE REPLACEMENT?

A. No. The dollars represented above are for main replacement projects only. The Company indicated that these costs do not include service line replacement costs associated with main replacement.[15]

Q. WHAT IS UGI GAS DOING TO HELP REDUCE RESTORATION COSTS?

A. UGI Gas indicated in its response to I&E-PS-19[16] that it is continuing efforts to lower restoration costs. The Company is continuing its efforts by utilizing

[14] I&E Exhibit No. 4, Schedule No. 3.
[15] I&E Exhibit No. 4, Schedule No. 3.
[16] I&E Exhibit No. 4, Schedule No. 2.

technical skills training in modern paving and restoration methods, cross-functional training for employees to optimize workforce deployment, standardization of procedures to ensure consistency throughout projects, checklists and audits to ensure each phase has followed each necessary step, efficiency improvements to optimize workflow, collaboration and communication with internal personnel as well as municipal and state personnel. Table 1 also indicates that in 2025, UGI Gas was successful with reducing restoration costs while also increasing its miles replaced/retired.

Q. WHEN CAPITAL IS UTILIZED FOR MORE ANCILLARY SPENDING SUCH AS RESTORATION COSTS, DO THE ADDED COSTS REDUCE THE FUNDS AVAILABLE FOR PIPELINE REPLACEMENT?

A. Yes. The increasing restoration costs divert funds from UGI Gas' pipeline replacement projects. The fewer projects UGI can complete in a year equates to less risky pipes being replaced, reducing the desired abandonment/removal of total pipeline risk. If UGI Gas spends less on restoration costs, then more funds are available for pipeline replacement.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING UGI GAS' MAIN REPLACEMENT COSTS AND SPECIFICALLY RESTORATION COSTS?

A. Yes. I recommend that UGI Gas continue to take positive steps toward reducing

restoration costs as shown in 2025, by coordinating pipe replacement projects with other street projects and replacing pipe using trenchless construction techniques where it is economically feasible. UGI Gas should work to negotiate with state, county, and local entities to reduce restoration requirements associated with pipeline replacement. UGI Gas should analyze and consider these costs on a project-by-project basis in an effort to continue to decrease and draw down these replacement costs annually.

Q. ARE YOUR RECOMMENDATIONS STATED ABOVE COMPLETE AS OF THE WRITING OF YOUR DIRECT TESTIMONY?

A. Yes. Based on the information provided by UGI Gas in discovery responses to date, my recommendations are complete at this time. However, I am still awaiting responses to several outstanding interrogatories. I reserve the right to supplement my discussion and recommendations after I receive those responses, which may be included in either rebuttal testimony or surrebuttal testimony.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Anna L. Ritchie

Professional and Educational Experience

Professional Experience

January 2022 – Present
Civil Engineer, Pipeline Safety Division, Bureau of Investigation and Enforcement
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania

Education and Training

Pennsylvania State University, 2019
Bachelor of Science, Civil Engineering

United States Pipeline and Hazardous Materials and Safety Administration
(PHMSA) Inspector Certification (22 classes)

I&E Exhibit No. 4
Witness: Anna L. Ritchie

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Exhibit to Accompany

the

Testimony

Of

Anna L. Ritchie

Bureau of Investigation and Enforcement

Concerning:

METHANE DETECTOR PILOT PROGRAM
PIPELINE REPLACEMENT COSTS

I&E-PS-7

Request:

Reference Direct Testimony of Jill E. Walters Statement 3, page 19, lines 15-18. Provide results for how the Natural Gas Safety Ambassador program has progressed since its implementation. Describe how UGI Gas has implemented the planned 500 Methane Detectors (MDs) and Smart Remote Methane detectors (SRMDs) and how it continues to distribute them over the two-year pilot program. Describe how many MDs and SRMDs have been implemented to date.

Response:

UGI has joined a Gas Technical Institute, GTI, project studying cellular communicating SRMDs along with other utilities across the country. As part of this project, the participating utilities were given cellular communicating units from two different manufacturers' for installation at customer premises. UGI has installed all of the SRMDs that it received from the GTI project. Both manufacturers SRMDs will notify UGI when 10% LEL is reached at the unit at which UGI will respond.

UGI targeted installation of these SRMDs in employees' homes who also had an inside gas meter. Through the work to identify and communicate with its employees to find participants for this pilot program, UGI discovered that there is a lack of awareness and education on the availability of Natural Gas Detectors.

This is when UGI initiated the Natural Gas Safety Ambassador program. This program was established to educate UGI employees on Natural Gas Detectors. UGI has used many different communication methods including emails, message boards, intranet postings, and a town hall presentation to bring awareness of these Natural Gas Detectors to its employees.

Since the start of the Natural Gas Safety Ambassador program, over 200 UGI employees, that are also UGI Gas customers, have received a Natural Gas Detector for their home and in doing so have become advocates to their family and friends in leading gas safety as a shared responsibility.

After this strong internal base of Natural Gas Safety Ambassadors had been established, UGI looked to reach out and educate its customers. UGI started the Natural Gas Detector Program in February 2026. A targeted marketing letter campaign was established to reach out to customers who have had a recent odor complaint inside their home and upon our

I&E-PS-7 (Continued)

visit, the UGI technician found natural gas readings. As of 3/13/2026, this mailing has targeted 1,355 customers. From those letters UGI has collected 228 requests and as of 3/13/26 the company has shipped out 212 units to those customers. A copy of the communication is attached as Attachment-I&E-PS-7.

In addition to this targeted marketing, UGI has either completed or is in development of other ways to contact and educate customers about the availability and importance of having Natural Gas Detectors in their homes. These activities include:

- A company website dedicated to Natural Gas Detectors education
- Updates to Call Center scripts
- 3rd party storefront to host UL 1484 tested Natural Gas Detectors for customers to purchase
- Education to 4th grade classrooms
- Educational materials accompanying the scratch and sniff mailers
- Call Center on hold messaging
- Customer newsletters

UGI Utilities, Inc.
1 UGI Drive
Denver, PA 17517

(800) 276-2722

Energy to do more®

«Name»
«Address_Line_1»
«Address_Line_2»

Hello UGI Natural Gas Customer,

UGI Utilities, Inc. is committed to the safe and reliable delivery of energy to our customers' homes and businesses. Our customers play an important role in natural gas safety. ***Smell Gas? Act Fast!*** is the life-saving advice we always want you to remember. In addition to knowing what to do if you suspect a leak, UGI also encourages you to have every layer of safety possible to protect your family. This includes natural gas detectors.

As part of UGI's Natural Gas Detector Program, we are working to get detectors into more homes and raise awareness of their availability and uses. You are receiving this safety outreach because you recently reported a natural gas leak in your home and UGI would like to offer you a **free** combination natural gas and carbon monoxide (CO) detector while supplies last per customer.

These detectors function like smoke alarms but are specifically designed to sense methane, the main component of natural gas. Detectors should be placed high on walls or near ceilings close to gas appliances. When a leak is detected, the detectors emit a loud alarm, giving your family time to evacuate.

If you would like a free detector for your home, go to https://www.ugi.com/natural-gas-safety/detectors/request-form/ and fill out the request form. Please remember, UGI has a limited supply of free detectors.

While detectors are not a substitute for routine appliance maintenance or other safety measures, it is an additional layer of protection. UGI urges anyone who smells the rotten-egg-like smell added to natural gas to act fast regardless of whether the detector alarm goes off or not. Evacuate at least the length of a football field away and then call 911 or UGI at 800-276-2722.

As a valued customer of ours, UGI urges you to take advantage of this offer. If our limited supply of free detectors is gone, please know that many retailers sell natural gas detectors. For more on gas safety, and how to properly use natural gas detectors, go to https://www.ugi.com/natural-gas-safety/detectors/.

I&E-PS-19

Request:

Describe how UGI Gas' efforts have lowered the restoration cost associated with facility replacement per year from the last 10 years.

Response:

Focusing on UGI Gas' efforts to enhance the paving and restoration team's development and standardization of procedures, here's a detailed overview of how these initiatives have contributed to lowering restoration costs associated with facility replacement over the past decade.

Team Development -

UGI Gas has established comprehensive training programs for the paving and restoration teams.

This includes-

Technical skills training in modern paving techniques and restoration methods.

Cross-Functional Training: Employees are trained in multiple roles, enhancing flexibility and responsiveness when addressing restoration needs. This reduces downtime and optimizes workforce deployment.

Standardization of Procedures -

Detailed guidelines on materials, techniques, and equipment usage that ensure consistency across projects. A focus on quality control to ensure that restorations meet established standards, reducing the need for rework.

Implementation of Checklists & Audits -

Standardized checklists for each phase of the restoration process help ensure that all necessary steps are followed, minimizing errors and omissions. Restoration audits are also performed to ensure quality work and procedures are being followed.

I&E-PS-19 (Continued)

Efficiency Improvements-

Streamlined Workflow-By standardizing procedures, UGI has optimized workflows, which have led to faster completion times for restoration projects. This has a direct impact on cost savings.

Performance Metrics and Continuous Improvement-

Data Collection and Analysis- UGI has implemented systems and scorecards to track performance metrics related to restoration projects, including time taken, costs incurred, and quality outcomes. As an example, please see CONFIDENTIAL Attachment I&E-PS-17(2).

Collaboration and Communication-

Integrated Teams- Enhanced collaboration between the paving and restoration teams, as well as with other departments (like Operations and Engineering), has improved project coordination.
Municipal and State coordination efforts, which include ahead of paving work, shared cost on total roadway reconstruction to improve the road conditions for the public. These cost shares not only reduce overall paving cost but also help maintain a positive relationship with the Boroughs and City and also result in a lower overall restoration cost.

Through these focused efforts on team development and the standardization of procedures, UGI Gas has achieved reductions in restoration costs. The combination of skilled teams, efficient processes, and a commitment to continuous improvement has not only led to cost savings but also enhanced the quality and reliability of restoration work.

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

Main Replacement Plant Additions Placed in Service for 2015 through 2025

YEAR	CONTRACTOR COST	MATERIALS	OTHER[4]	RESTORATION	UGI L,E,&O[5]	Total[2, 6]	Miles Replaced / Retired[1, 3]	Average Cost Per Mile
2025	$ 85,824,850	$17,421,940	$35,844,482	$ 30,834,080	$ 5,561,151	$ 175,486,503	67	$ 2,621,549
2024	$ 64,371,591	$12,532,048	$37,480,333	$ 34,399,430	$ 5,251,247	$ 154,034,648	44	$ 3,494,434
2023	$ 84,279,195	$16,003,694	$35,466,531	$ 38,154,361	$ 4,168,859	$ 178,072,639	54	$ 3,322,251
2022	$ 80,855,957	$13,918,122	$31,241,083	$ 41,051,972	$ 5,443,306	$ 172,510,440	73	$ 2,353,485
2021	$ 55,983,890	$11,244,434	$26,940,946	$ 32,225,958	$ 5,041,239	$ 131,436,467	101	$ 1,301,351
2020	$ 35,213,216	$11,324,916	$14,205,259	$ 18,899,503	$ 3,311,317	$ 82,954,210	60	$ 1,373,414
2019	$ 39,081,008	$ 7,251,994	$17,380,150	$ 10,828,471	$ 4,683,465	$ 79,225,088	85	$ 932,060
2018	$ 41,385,561	$ 7,603,776	$18,559,471	$ 13,922,627	$ 4,756,590	$ 86,228,024	65	$ 1,323,734
2017	$ 38,546,872	$ 7,093,547	$13,561,104	$ 14,470,861	$ 4,103,088	$ 77,775,472	72	$ 1,077,223
2016	$ 28,080,385	$ 5,725,594	$ 9,619,243	$ 5,980,115	$ 3,952,621	$ 53,357,958	69	$ 777,133
2015	$ 22,688,853	$ 4,600,201	$10,281,963	$ 11,654,249	$ 1,642,461	$ 50,867,728	88	$ 576,732

Notes:

1. Mileage represented is priority pipe only including cast iron, wrought iron, and bare steel pipe.
2. Dollars presented are for main replacement projects only. These costs do not include service replacement costs associated with main replacement.
3. The mileage shown for 2015-2025 is the delta in the DOT reports which is the net of replacement, retirement, and reclassifications.
4. Other costs include capitalized overheads, permits, environmental costs, and AFUDC.
5. UGI L,E,&O is defined as internal UGI labor, transportation costs and equipment.
6. Dollars shown reflect assets placed in service for the fiscal years.

I&E Statement No. 1-SR
Witness: Zachari Walker
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES INC. – GAS DIVISION

Docket No. R-2025-3059523

Surrebuttal Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission or PUC) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME ZACHARI WALKER WHO SUBMITTED I&E STATEMENT NO. 1 AND I&E EXHIBIT NO. 1?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) witnesses Tracy Hazenstab,[1] Vivian Ressler,[2] and Amy Keller.[3] I also present I&E's updated position based on my updated recommended operating and maintenance (O&M)

[1] UGI Gas Statement No. 2-R.
[2] UGI Gas Statement No. 4-R.
[3] UGI Gas Statement No. 5-R.

expense, tax, and rate base adjustments, and the updated adjustments of the other I&E witnesses identified below.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1-SR contains schedules that support my surrebuttal testimony. Additionally, I reference my direct testimony and accompanying exhibit as I&E Statement No. 1 and I&E Exhibit No. 1, respectively.

SUMMARY OF COMPANY'S UPDATED REQUEST

Q. PLEASE SUMMARIZE THE COMPANY'S UPDATED REQUESTED REVENUE INCREASE.

A. In rebuttal testimony, the Company updated its requested revenue increase to $98,693,000 to the updated claimed present rate revenues, $1,235,719,000, resulting in an overall revenue requirement of $1,334,412,000.[4] The Company's request represents a 12.76% ($98,693,000 ÷ $773,312,000)[5] increase to the Company's claimed present rate distribution revenues, excluding commodity revenues from the calculation. As noted in my direct testimony, these charges must be excluded when calculating the magnitude of the requested revenue increase to illuminate the full impact of the distribution revenue increase requested.[6]

[4] UGI Gas Rebuttal Exhibit A, Schedule A-1.
[5] UGI Gas Rebuttal Exhibit A, Schedule D-1, Line 4 ÷ Line 1.
[6] I&E Statement No. 1, p. 3.

Q. HAS THE COMPANY ACCEPTED ANY OF YOUR RECOMMENDED ADJUSTMENTS FROM DIRECT TESTIMONY?

A. Yes. The Company accepted my recommended payroll adjustment of $1,153,000, and corresponding adjustments to payroll tax of $88,000 and employee benefits expenses of $764,000, based on my recommended vacancy rate of 6.15%.[7]

SUMMARY OF RECOMMENDED O&M ADJUSTMENTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO THE COMPANY'S REBUTTAL POSITION.

A. The following table summarizes my updated recommended adjustments:

	UGI Gas FPFTY Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Rate Case Expense	$1,760,000	$880,000	($880,000)
Advertising Expense	$2,061,000	$1,415,000	($646,000)
Employee Activity Costs	$583,000	$388,000	($195,000)
Membership Dues and Subscriptions	$1,593,000	$1,456,000	($137,000)
[BEGIN PROPRIETARY]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]
		[END PROPRIETARY]	
Rate Base:			
Cash Working Capital	$66,348,000	$65,718,000	($630,000)
[BEGIN PROPRIETARY]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]
		[END PROPRIETARY]	

[7] UGI Gas Statement No. 4-R, p. 2.

SUMMARY OF I&E'S SURREBUTTAL POSITION

Q. WHAT IS I&E'S UPDATED TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for UGI Gas is $1,292,425,000. This recommended revenue requirement represents an increase of $56,706,000 to the Company's present rate revenues of $1,235,719,000. This total recommended allowance incorporates my adjustments made in this surrebuttal testimony to O&M expenses, rate base, and those made in the surrebuttal testimony of I&E witnesses Drew Breuning [8] and Ethan Cline.[9]

A calculation of the I&E recommended revenue requirement is shown in the table below:

[8] I&E Statement No. 2-SR.
[9] I&E Statement No. 3-SR.

[BEGIN PROPRIETARY]

[END PROPRIETARY]

PUC ANNUAL REPORT FORMAT

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY REGARDING THE COMPANY'S PUC ANNUAL REPORT FILINGS.

A. Historically, the PUC's Gas Annual Report of UGI Utilities, Inc. (Annual Report) has been filed containing schedules that also include data for the electric operations of UGI Gas' parent company. I recommended that the Company be required to display all schedules included in its Annual Report, including Schedules 200, 213, and 216, with disaggregated data for gas and electric

operations. My recommendation was supported by the Company's ability to produce segmented data for gas and electric operations in its parent company's Federal Energy Regulatory Commission (FERC) Form 1 filing. Since the Company is able to attribute financial measures to the disparate business segments for the annual financial and operating report filed with FERC, UGI Gas should be able to do so at the state level as well.[10]

Additionally, I noted that requiring all schedules to contain disaggregated data for gas and electric operations would be more useful to parties involved in base rate cases and other proceedings when conducting comparative analysis.[11]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Amy Keller disagrees with my recommendation.[12]

Q. SUMMARIZE UGI GAS WITNESS KELLER'S RESPONSE.

A. Ms. Keller contends that while the Company is able to present separate data for utility plant accounts outside of common plant assets, such as on Schedules 205 and 205.1 in the PUC Annual Report, UGI Gas cannot provide operation-specific schedules for items such as cash, long-term debt, deferred income taxes, and equity because they are maintained at the legal entity level and have no inherent

[10] I&E Statement No. 1, pp. 6-7.
[11] I&E Statement No. 1, pp. 7-8.
[12] UGI Gas Statement No. 5-R, pp. 7-8.

gas or electric character.[13] Additionally, she asserts that the current Annual Report schedules present consolidated balance sheet items that exist at the legal entity level of UGI Utilities, Inc., UGI Gas' parent company.[14]

Q. WHAT IS YOUR RESPONSE TO WITNESS KELLER'S ASSERTION?

A. Ms. Keller's statement regarding UGI Gas' inability to provide disaggregated schedules for operation-specific data is severely undercut by the announcement that UGI Utilities, Inc. plans to sell its Electric Division (UGI Electric) to funds managed by Argo Infrastructure Partners LP (Argo) for approximately $470,000,000.[15] If the sale is approved, the Company's PUC Annual Report filing would only include data specific to the Gas Division's operations. Thus, it stands to reason that UGI Gas should be able to provide the PUC Annual Report with disaggregated data regardless of any sale of UGI Electric.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION REGARDING THE COMPANY'S PUC ANNUAL REPORT FILINGS?

A. No. I continue to recommend that the Company be required to file future Annual Reports containing segmented data separately for gas and electric operations.

[13] UGI Gas Statement No. 5-R, p. 7.
[14] UGI Gas Statement No. 5-R, p. 8.
[15] https://ugi.reportablenews.com/pr/ugi-utilities-and-argo-infrastructure-partners-reach-agreement-on-purchase-and-sale-of-ugi-s-pa-electric-utility, accessed May 14, 2026.

Q. GIVEN THE PROPOSED SALE OF UGI UTILITIES, INC. – ELECTRIC OPERATIONS TO ARGO, IS YOUR RECOMMENDATION STILL RELEVANT?

A. Yes. The transaction is not expected to be finalized until the first quarter of 2027,[16] which means the Company will produce at least one more PUC Annual Report filing, assuming regulatory delays or other complications are not a factor. However, if the transaction does not take place, requiring the Company to file future Annual Reports with separate segmented data would be more useful to the parties involved in future base rate cases and other proceedings when conducting comparative analysis.

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION FOR RATE CASE EXPENSE IN YOUR DIRECT TESTIMONY.

A. I recommended a normalized annual allowance of $880,000 for rate case expense, or a reduction of $880,000 ($1,760,000 - $880,000) for the Company's claim.[17] My recommendation was based on adjusting the normalization period for rate case expense to match the historic average base rate case filing frequency of 24 months.[18] My recommendation is consistent with the Commission's emphasis on

[16] https://ugi.reportablenews.com/pr/ugi-utilities-and-argo-infrastructure-partners-reach-agreement-on-purchase-and-sale-of-ugi-s-pa-electric-utility, accessed May 14, 2026.
[17] I&E Statement No. 1, p. 10.
[18] I&E Statement No. 1, p. 11.

the importance of considering the utility's historic rate case filing frequency when determining the normalization period of rate case expenses.[19]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Tracy Hazenstab disagrees with my recommendation.[20]

Q. SUMMARIZE WITNESS HAZENSTAB'S RESPONSE.

A. Ms. Hazenstab opines that my recommended 24-month normalization period, based on the Company's historic average rate case filing frequency, is not reflective of the Company's rate case filing frequency because it is the Company's expectation that it will file another base rate case in one year based on a list of internal factors, including the Company's Third Long-Term Infrastructure Improvement Plan.[21]

Q. WHAT IS YOUR RESPONSE TO MS. HAZENSTAB'S ASSERTION?

A. As referenced in my direct testimony, in the 2012 PPL Electric Utilities Corporation (PPL Electric) base rate case, when PPL Electric did not file its next base rate case at the anticipated interval, PPL Electric's ratepayers were still paying rates that included a provision for a higher rate case expense based on the

[19] I&E Statement No. 1, pp. 12-14.
[20] UGI Gas Statement No. 2-R, p. 6.
[21] UGI Gas Statement No. 2-R, p. 6.

shorter anticipated normalization period rather than if the interval would have been based on PPL Electric's experienced historic average filing frequency.

Using the historic average filing frequency to determine the interval over which to normalize rate case expense provides protection for ratepayers from potentially significant over-recoveries of expenses in rates when the expense occurs irregularly.

The Company has not demonstrated that it will file its next base rate case within 12 months of the instant filing, and it is not required to refund any over-recovery should it miss its anticipated filing date. Therefore, normalizing the Company's rate case expense claim over the historic average filing frequency is more appropriate.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. No. I continue to recommend an annual allowance for rate case expense of $880,000, based on a 24-month normalization period consistent with the Company's historic average filing frequency. My recommendation continues to represent a reduction of $880,000 ($1,760,000 - $880,000) for the Company's claim.

ADVERTISING EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION FOR ADVERTISING EXPENSE IN YOUR DIRECT TESTIMONY.

A. My recommended advertising expense allowance was based on the sum of: (1) the historical two-year average of Fiscal Year (FY) 2024 and Future Test Year (FTY) 2025 advertising expense for the Public Health & Safety programs of $957,000 [($1,026,000 + $887,000) ÷ 2], Conservation of Energy programs of $156,000 [$76,000 + $235,000) ÷ 2],[22] Explanation of Bill Practices $173,000 [($178,000 + $167,000) ÷ 2], and Other Advertising Programs – Stakeholder Newsletters $129,000 [($127,000 + $131,000) ÷ 2]; and (2) removal of the entire claim for Other Advertising Programs - Community Event Sponsorships of $191,000. The basis for my recommendation for the expenses listed in Item 1 above was that the historical two-year average for these expenses represented more appropriate expense levels compared to the Company's substantial 31.76% total proposed increase for these categories from the Historic Test Year (HTY) to the Fully Projected Future Test Year (FPFTY). My recommendation for the Other Advertising Programs – Community Event Sponsorships was based on those advertising expenses not satisfying the criteria enumerated in 66 Pa. C.S.A. § 1316(a) regarding the recovery of advertising expenses allowable for ratemaking

[22] In response the Company's response to I&E-RE-43, UGI Gas did not include $2,500 in expenses related to FY 2024 Conservation of Energy radio advertising. This expense was originally included in the total FY 2024 Conservation of Energy expense in UGI Gas Book I, Section 53.53, Attachment III-A-25, totaling $76,000 ($72,000 + $3,000 + $1,000). In my direct testimony, I used this expense total rather than the $73,000 stated in response to I&E-RE-43 to calculate the Conservation of Energy historical two-year average advertising expense.

purposes, and therefore, were not appropriate to claim for ratemaking purposes.[23]

My recommended allowance of $1,415,000 for advertising expense represented a reduction of $646,000[24] ($2,061,000 - $1,415,000) to the Company's advertising expense claim.[25] This reduction of $646,000 consists of the following reductions to individual categories of advertising expense: $134,000 for Public Health & Safety; $117,000 for Conservation of Energy; $145,000 for Explanation of Bill Practices; $60,000 for Other Advertising-Stakeholder Newsletters; and $191,000 for Other Advertising-Community Event Sponsorships.[26]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.[27]

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler opines that the significant increases to the Public Health and Safety, Conservation of Energy, Explanation of Bill Practices, and Stakeholder Newsletters categories are due to the costs of procuring space for advertising continuing to increase.[28]

Then she addresses my recommendation to remove the expenses related to community event sponsorships stating these expenses are necessary because they

[23] I&E Statement No. 23-27.
[24] The total recommended reduction variance is due to rounding.
[25] I&E Statement No. 23-27.
[26] I&E Statement No. 1, p. 25.
[27] UGI Gas Statement No. 4-R, pp. 23-27.
[28] UGI Gas Statement No. 4-R, p. 23.

support events that present information about billing, customer programs, safety, or utility services.[29] Further, Ms. Ressler asserts that these sponsorship opportunities attract potential employees and customers, the latter, according to her, will reduce the per-customer cost burden of existing customers.[30] Lastly, she states that these expenses are necessary so that non-customers may visit locations which are fueled by natural gas and benefit from understanding how to respond in case of a natural gas emergency.[31]

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER'S ASSERTION?

A. Ms. Ressler has not provided support for the claimed increased costs to procure advertising space in the form of invoices or other supporting documentation. Therefore, I continue to recommend the historic two-year average expense as the basis for advertising claims for Public Health and Safety, Conservation of Energy, Explanation of Bill Practices, and Stakeholder Newsletters.

Regarding Community Event Sponsorships, I do not find the argument that the costs of $191,000 are necessary for dissemination of safety information compelling given my recommendation for an allowance of $957,000 for Public Health and Safety included for ratemaking purposes. Further, she did not provide evidence that attracting additional customers to UGI Gas' distribution system has historically reduced the per-customer cost burden for existing customers.

[29] UGI Gas Statement No. 4-R, p. 24.
[30] UGI Gas Statement No. 4-R, p. 25.
[31] UGI Gas Statement No. 4-R, p. 25.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. No. I continue to recommend an allowance of $1,415,000 for advertising expense or a reduction of $646,000[32] ($2,061,000 - $1,415,000) to the Company's advertising expense claim based on lack of support for the 31.76% increased expense claims for Public Health and Safety, Conservation of Energy, Explanation of Bill Practices, and Stakeholder Newsletters and the Community Event Sponsorships expenses being inappropriate to include for ratemaking purposes. My recommendation provides more reasonable advertising expense levels than the Company's substantially increased claims over the HTY actual expenses.

Additionally, the Company has not provided adequate support for the Community Event Sponsorship expenses being necessary for the provision of safe and reliable natural gas service. As stated in my direct testimony, the Company's Community Event Sponsorship program is represented by advertisements for events such as the Parade of Homes, the Fulton Theatre, and the Reading Royals minor professional ice hockey team,[33] all of which represent goodwill, or promotional advertising and do not directly benefit ratepayers. Further, it is unclear which of the six criteria of 66 Pa. C.S.A. § 1316(a) the Company is suggesting these expenses meet. I&E prosecutors will address this topic more

[32] The total recommended reduction variance is due to rounding.
[33] I&E Statement No. 1, p. 26.

fully in briefs. The Company's Community Event Sponsorships $191,000 claim is inappropriate and should be disallowed for ratemaking purposes.

EMPLOYEE ACTIVITY COSTS

Q. SUMMARIZE YOUR RECOMMENDATION FOR EMPLOYEE ACTIVITY COSTS IN YOUR DIRECT TESTIMONY.

A. I recommended an allowance of $388,000 or a reduction of $195,000 ($583,000 - $388,000) based on my recommended disallowance of the costs for the Company picnic of $195,000 for ratemaking purposes due to company picnics not directly supporting the provision of safe and reliable gas service, and therefore they should not be funded by ratepayers.[34]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.[35]

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler contends that the costs for the Company picnic should be allowed as that annual picnic is intended to recognize employee contributions, celebrate employee milestones, and acknowledge employees' operational performance.[36] She also referenced the Commission's decision in the 2018 UGI Utilities – Electric

[34] I&E Statement No. 1, pp. 28-29.
[35] UGI Gas Statement No. 4-R, pp. 20-22.
[36] UGI Gas Statement No. 4-R, p. 21.

Division (UGI Electric) base rate case at Docket No. R-2017-2640058 in which the Commission agreed with the Administrative Law Judge's recommendation to allow UGI Electric's claim $11,848 for employee activity expenses, most of which was attributable to UGI Electric's annual picnic.[37] She uses this referenced decision as support for the Company's inclusion of employee activity costs of $195,000 in the instant proceeding for the Company's annual picnic.[38]

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER'S ASSERTION?

A. I disagree with Ms. Ressler's assertion that the Commission's decision in the 2018 UGI Electric base rate case at Docket No. R-2017-2640058 which found in favor of the $11,848 claim for employee activity expenses related to UGI Electric's annual picnic[39] supports UGI Gas' claim for an annual picnic costing $195,000 in this proceeding. The Company's claim of $195,000 for its annual picnic is unreasonable due to the current economic climate facing ratepayers, which is very different compared to the one during the 2017 UGI Electric case. If the Company chooses to hold this picnic, which is a cost of $127 per employee based on the 1,541-employee complement claimed in this case,[40] shareholders should be required to cover the cost.

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37 *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, Opinion and Order, pp. 69-71 (Order Entered October 25, 2018).

38 UGI Gas Statement No. 4-R, p. 22.

39 *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, Opinion and Order, pp. 69-71 (Order Entered October 25, 2018).

40 I&E Exhibit No. 1, Schedule 5, p. 2.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR EMPLOYEE ACTIVITY COSTS?

A. No. Under the current economic climate, I do not believe employee picnic costs should be included in base rates and funded by ratepayers. Therefore, I continue to recommend an allowance of $388,000 or a reduction of $195,000 ($583,000 - $388,000) to the Company's employee activity cost claim. As stated in my direct testimony, this claim does not directly support the provision of safe and reliable gas service and therefore should not be funded by ratepayers.

MEMBERSHIP DUES AND SUBSCRIPTIONS

Q. SUMMARIZE YOUR RECOMMENDATION FOR MEMBERSHIP DUES AND SUBSCRIPTIONS IN YOUR DIRECT TESTIMONY.

A. I recommended an allowance of $1,210,000, or a reduction of $383,000 ($1,593,000 - $1,210,000) to the Company's membership dues and subscriptions claim based on the following adjustments: (1) adjusting the amount included for ratemaking purposes for the Gas Technology Institute (GTI) to match the three-year average of historically incurred costs, a reduction of $246,000 ($371,000 - $125,000); and (2) removing the dues paid to numerous organizations, for a reduction of $137,000. My recommended membership dues and subscription adjustments were based on the unreasonable amount claimed for the Company's GTI membership dues and UGI Gas' claims for the identified organizations being

inappropriate to include for ratemaking purposes.[41] Additionally, I stated that my recommendation was not intended to dictate what memberships the Company contributes to, rather that ratepayers should not be required to fund the identified memberships.[42] Lastly, I noted that in the 2025 Columbia Gas base rate case, the Commission denied that utility's request to recover chamber of commerce fees in base rates, adopting the Administrative Law Judge's recommendation "that the Company not be permitted to recover chamber of commerce membership costs."[43]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.[44]

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler states that the increase in the dues paid to GTI are related to GTI's Operation Technology Development (OTD) program. According to her, this program allows UGI Gas to have access to advanced technology research and development activities and promotes improved safety, reliability, and operational efficiency of natural gas projects.[45]

Next, Ms. Ressler avers that the Company's membership costs for chambers of commerce and economic development agencies are imperative to

41 I&E Statement No. 1, pp. 28-32.
42 I&E Statement No. 1, p. 32.
43 I&E Statement No. 1, p. 33.
44 UGI Gas Statement No. 4-R, pp. 27-30.
45 UGI Gas Statement No. 4-R, p. 28.

grow its customer base by attracting new industrial and commercial customers. Further, she opines that without these memberships the Company would experience less commercial growth which would result in ratepayers having to pay higher costs.

Lastly, she contends that the relationships with the economic development corporations and chambers of commerce have led to $8,000,000 in grants which supported the expansion of UGI Gas' distribution network, stating that these grants obtained by commercial customers, the network expansions create opportunities for additional prospective residential customers.[46]

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER'S ASSERTION?

A. First, I have reviewed the supplemental response and the referenced testimony in UGI Gas' previous base rate case and found the nature of the dues paid to GTI for the OTD to be reasonable. I recommend the Commission require the Company to submit a supplemental response that provides further detail regarding the OTD program and further breakdown of the dues claimed for ratemaking purposes.

Next, I am not convinced by Ms. Ressler's rebuttal testimony that chamber of commerce memberships are necessary to attract new commercial and industrial customers and the related grants, and I continue to disagree that these memberships be funded by ratepayers.

[46] UGI Gas Statement No. 4-R, pp. 29-30.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR MEMBERSHIP DUES AND SUBSCRIPTIONS?

A. Yes. I am updating my recommended allowance for the Company's membership dues and subscriptions claim to $1,456,000, or a reduction of $137,000 ($1,593,000 - $1,456,000). The basis for my revised recommendation is my withdraw of my recommended adjustment to the GTI membership dues claim due to the fact that ratepayers will directly benefit from as a result of GTI's OTD program. My updated recommended adjustment represents the continued removal of the entities identified in my direct testimony that total $137,000 as dues paid to chambers of commerce and economic development agencies are not necessary for the provision of safe and reliable natural gas service. Therefore the $137,000 claimed for membership dues to chambers of commerce and economic development agencies should not be funded by ratepayers and should be disallowed for ratemaking purposes.

This recommendation continues to be supported by the Commission's disallowance of Columbia Gas' request in its 2025 base rate case to recover chamber of commerce fees in base rates when it adopted the Administrative Law Judge's recommendation "that [Columbia Gas] not be permitted to recover chamber of commerce membership costs."[47]

[47] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, Opinion and Order, p. 158 (Order Entered December 9, 2025).

INCENTIVE COMPENSATION

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING INCENTIVE COMPENSATION IN YOUR DIRECT TESTIMONY.

A. I recommended an allowance of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** or a reduction of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Company's expense claim. Additionally, I recommended an allowance of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** or a reduction of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Company's rate base claim.[48]

My recommendation was based on the removal of the Company's claims in part, or as a whole, that were inappropriate or unsupported for ratemaking purposes.[49] Additionally, my recommendation was supported by the Commission recent decision in the most recent Columbia Gas base rate case to remove of 70% of Columbia Gas' incentive compensation claim for ratemaking purposes, as detailed in my direct testimony.[50]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.[51]

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48 I&E Statement No. 1, p. 35.
49 I&E Statement No. 1, pp. 35-39.
50 I&E Statement No. 1, p. 40.
51 UGI Gas Statement No. 4-R, pp. 4-18.

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler contends that each of my recommended adjustments are made in error and that if the Company were not allowed to recover the entire incentive compensation claim through base rates, the UGI Gas would not be able to attract and retain qualified employees, managers, and executives.[52] She argues that if the Company did not offer stock compensation awards, alternative compensation would be necessary for the Company to retain its workforce.[53] Additionally, she identifies a plan I overlooked for equity compensation for UGI Corporation employees of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** that was included in attachment I&E-RE-32.8.[54] And finally, she identifies the remaining **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** as other employee compensation consisting of amounts for retention awards, signing bonuses, and similar ad hoc amounts.[55] Lastly, Ms. Ressler contends that my recommendation is an attempt to single out specific aspects of the Company's overall compensation program and that it is improper and should be rejected.[56]

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER'S ASSERTIONS?

A. First, to Ms. Ressler's point that my recommendation represents a targeted, precise singling out of aspect of the Company's overall compensation program, this is

[52] UGI Gas Statement No. 4-R, pp. 4, 9-12.
[53] UGI Gas Statement No. 4-R, pp. 7-8.
[54] UGI Gas Statement No. 4-R, pp. 8-9.
[55] UGI Gas Statement No. 4-R, p. 9.
[56] UGI Gas Statement No. 4-R, p. 8.

correct in that I focused on eliminated portions of the benefits that rely on financial performance metrics. I am not suggesting that the Company should discontinue offering incentive compensation plans. In fact, in my direct testimony, I recommended the Commission allow certain portions of the individual plans because the metrics that determine payout are related to safety and customer satisfaction. I am recommending that the portions of the individual plans I have identified be disallowed for ratemaking purposes, meaning that ratepayers should not fund programs or parts of programs designed to reward employees based on financial measures alone. Shareholders should be required to fund the portions of the incentive compensation programs that require financial performance criteria to earn additional compensation.

Next, following Ms. Ressler's identification of the **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** amount I previously referred to as unsupported, I continue to recommend this entire amount be disallowed for ratemaking purposes. This recommendation is based on the amount attributed to the Company's claim for equity compensation for UGI Corporation employees of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** is earned without **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** The remaining **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** represents compensation through **[BEGIN PROPRIETARY]** [redacted]

[57] I&E Exhibit No. 1-SR, Schedule 1, p. 4.

[redacted] **[END PROPRIETARY]** I recommend this amount be disallowed as it does not provide any meaningful benefit to ratepayers and as such is inappropriate to include for ratemaking purposes.

Recently, Governor Shapiro issued a letter to Pennsylvania Utility Leaders regarding higher utility costs and enormous profits earned by utilities in 2024.[59] This highlights the importance of ratepayers only being required to pay rates to fund costs that are necessary for the safe and reliable provision of natural gas service.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR THE COMPANY'S INCENTIVE COMPENSATION CLAIM?

A. Yes. The basis for my recommended disallowance has changed as noted above. However, my recommended allowance remains at **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** or a reduction of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Company's expense claim. Additionally, I continue to recommend an allowance of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** or a reduction of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Company's rate base claim.

[58] UGI Gas Statement No. 4-R, p. 9.
[59] I&E Exhibit No. 1-SR, Schedule 2, pp. 1-4.

ENERGY EFFICIENCY AND CONSERVATION PLAN EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION FOR EE&C PLAN EXPENSE IN YOUR DIRECT TESTIMONY.

A. I recommended an FPFTY allowance of $10,833,000 be included for ratemaking purposes. This represented a reduction of $1,193,000 ($12,026,000 - $10,833,000) to the Company's claim. My recommended allowance was based on applying the historical three-year average cost variance of 87.6% to the unadjusted budgeted EE&C Plan expenses of $12,366,000, which resulted in my recommended EE&C Plan expense allowance of $10,833,000 ($12,366,000 x 0.876).[60] My recommendation was intended to set a more accurate expense level to include for ratemaking purposes for the Energy Efficiency and Conservation Plan (EE&C Plan) expenses since the Company has been historically unable to fully spend the EE&C Plan budget or achieve the budgeted EE&C Plan savings, as further described in my direct testimony.[61] My recommended allowance used the three-year historical average cost variance to set an appropriate EE&C Plan expense level and balance the benefits of a properly funded EE&C Plan with a reasonable expense level to include for ratemaking purposes.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Tracy Hazenstab disagrees with my recommendation.[62]

[60] I&E Statement No. 1, pp. 41-44.
[61] I&E Statement No. 1, pp. 43-44.
[62] UGI Gas Statement No. 2-R, pp. 7-8.

Q. SUMMARIZE MS. HAZENSTAB'S RESPONSE.

A. Ms. Hazenstab states that the EE&C Plan costs are not recovered through base rates and that the related expenses are set to fully offset the EE&C Rider revenues and there is no impact on the revenue requirement.[63]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION IN RESPONSE TO MS. HAZENSTAB'S REBUTTAL TESTIMONY?

A. Yes. Based on her clarification, I find it necessary to withdraw my recommended adjustment to the EE&C Plan.

CASH WORKING CAPITAL

Q. SUMMARIZE YOUR RECOMMENDATION FOR CASH WORKING CAPITAL IN YOUR DIRECT TESTIMONY.

A. I recommended a total allowance of $65,691,000, or a reduction of $832,000 ($66,523,000 - $65,691,000) to the Company's claim based on my adjustments to cash-based O&M expenses as discussed in my direct testimony.[64] A summary of my recommended adjustments follows:

[63] UGI Gas Statement No. 2-R, p. 7.
[64] I&E Statement No. 1, pp. 45-47.

O&M Expense	I&E Recommended Adjustment
Payroll – Expense Lag Days	
Payroll Expense	($1,153,000)
Other Expenses – Expense Lag Days	
Rate Case Expense	($880,000)
Employee Pension and Benefits (net of pension and other post-employment benefits)	($764,000)
Advertising Expense	($646,000)
Employee Activity Costs	($195,000)
Membership Dues and Subscriptions	($383,000)
EE&C Plan Expense	($1,193,000)
Incentive Compensation Expense **[BEGIN PROPRIETARY]**	[redacted]
	[END PROPRIETARY]
Total [BEGIN PROPRIETARY]	[redacted]
	[END PROPRIETARY]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas Witness Tracy Hazenstab disagrees with my recommendation in as much as she disagrees with my recommended adjustments.[65]

Q. DID THE COMPANY UPDATE ITS CWC CLAIM?

A. Yes. The Company's updated CWC claim is $66,348,000.[66]

[65] UGI Gas Statement No. 2-R, p. 8.
[66] UGI Gas Rebuttal Exhibit A, Schedule C-4, p. 1, Line 5.

Q. DO YOU AGREE WITH THE COMPANY'S UPDATED CWC CLAIM?

A. No.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR CWC?

A. Yes. I am updating my CWC recommendation to reflect the Company's updated CWC claim and my updated cash-based O&M expense recommendations. I recommend a total updated allowance of $65,718,000, or a reduction of $630,000 ($66,348,000[67] - $65,718,000) to the Company's updated claim based on my updated adjustments to cash-based O&M expenses.

Q. SUMMARIZE WHERE EACH OF THE UPDATED RECOMMENDED O&M EXPENSE ADJUSTMENTS ARE REFLECTED IN THE CWC COMPUTATIONS.

A. My O&M expense adjustments were made to the Company's electronic CWC calculation as follows:

Other Expenses – Expense Lag Days:

The following recommended adjustments are reflected in the Other Expenses - Expense Lag Days calculation:[68] rate case expense adjustment of $880,000, advertising expense adjustment of $646,000, employee activity cost adjustment of

[67] UGI Gas Rebuttal Exhibit A, Schedule C-4, p. 1, Line 5.
[68] I&E Exhibit No. 1-SR, Schedule 3, p. 2, Line 15.

$195,000, membership dues and subscriptions adjustment of $137,000, and incentive compensation expense adjustment of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** as discussed above, producing a total decrease of **[BEGIN PROPRIETARY]** [redacted] **[END PROPRIETARY]** to the Other Expenses Lag Days calculation.

Q. IS YOUR RECOMMENDED CWC ALLOWANCE A FINAL RECOMMENDATION?

A. No. All adjustments to UGI Gas' claims for revenues, expenses, taxes, and rate base must be consistently brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, which is known as iteration, effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Exhibit No. 1-SR
Witness: Zachari Walker
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES INC. – GAS DIVISION

Docket No. R-2025-3059523

Exhibit to Accompany

The

Surrebuttal Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

RATE BASE

GOVERNOR JOSH SHAPIRO

April 29, 2026

Dear Utility Leaders:

As you are no doubt aware, many of your customers across the Commonwealth are experiencing markedly higher utility costs. Rising utility bills have themselves become drivers of inflation. While there are many factors affecting those increases, several core causes are directly within your control and result from your policy and fiscal decisions, including the excessive rate requests several utilities have sought in recent years. Last year alone, 13 Pennsylvania utilities requested $975 million in higher rates after those very same utilities had earned a total of $1.4 billion in profits in 2024.

We have reached a tipping point, and this is a moment to put your customers first and change the behaviors causing rate increases. As I've expressed publicly and privately, I believe the 20th century utility model is broken—we can no longer simply prioritize corporate profitability to drive infrastructure development. Rather, we must be laser focused on delivering on the actual needs of our communities. As I stated clearly in my Budget Address in February, Pennsylvania consumers should not be asked to pay a single dollar more than is needed to support a safe and reliable utility system.

Change is needed, and my Administration stands ready to support each Pennsylvania utility in raising the capital you need to invest in your service territories and workers, both in modernizing with cost-effective new technologies and maximizing the existing infrastructure that you have developed over time. However, as we work together to implement this new approach, you must seek to procure that capital in more affordable ways, conscious of the utility burdens facing many consumers across our Commonwealth.

I write today to lay out three commonsense practices to ensure the needs of Pennsylvanians come first. My Administration will use these three practices as a benchmark to evaluate rate case proposals going forward. Let me be clear: my Administration and I will vocally and forcefully oppose rate case requests from utilities that fail to adhere to these three commonsense practices.

First, utilities should seek to raise the most cost-effective forms of capital. Best practices now require you to protect consumers by disfavoring expensive equity when lower-cost debt is available. Given the low risk profile of monopolistic utilities, which maintain a captive rate base able to repay obligations over time, consumers should not be expected to bolster corporate profits through over reliance on costly equity. This means debt should normally represent a clear majority of a utility's proposed ratemaking capital structure, as it does in many other lower-risk industries. As one measure of this approach, any equity share proposed in a rate case in excess of the amount of equity employed by the utility's parent holding company will require extraordinary justification to receive my Administration's support.

For utilities looking to find low-cost sources of capital, my Administration encourages you to apply to the Department of Energy, which is currently offering loan terms as favorable as the 10-year U.S. Treasury yield plus 35 basis points. By comparison, the average Pennsylvania utility requested a return on equity a staggering 682 basis points above the 10-year U.S. Treasury yield last year. Before raising such expensive equity, you should take advantage of more affordable sources of capital, like these loans, that many of your fellow utilities across the country are pursuing. My Administration stands ready to facilitate an introduction to loan officers at the Department of Energy upon your request.

Second, whenever new revenue is sought, a utility must explain in plain, clear language why its proposed investments are necessary, using transparent data to identify a specific reliability or safety concern that will be addressed, or demonstrating with a thorough cost/benefit analysis that the investment will produce significant savings or reliability benefits for consumers. This means showing the value customers will receive in terms of discrete improvements producing tangible outcomes that are timebound, verifiable, and logically linked to the need for additional capital. Creating real value for customers also means maximizing existing grid resources in ways that control costs and defer the need for future upgrades. You must also describe explicitly what amount of your

requested rate increase will be remitted to shareholders through corporate dividends or other means, as compared to what would be used to directly advance the needs of your customers.

Third, you must provide transparent, justifiable equity returns. Pennsylvania has a long, proud tradition of trusting free markets to deliver fair, transparent pricing. In fact, this year marks the 30th anniversary of Act 138, which introduced competition into our utility sector for the first time. That bipartisan law embodies Pennsylvania's deep-seated belief that free-market competition—when properly implemented and overseen—is the best tool for delivering customers the fair value they deserve. Today, we use markets to price our wholesale power and rely on principles of competition to fairly and impartially award public contracts. Yet less accurate administrative determinations—essentially amounting to educated guesses—still govern how much utilities earn on their equity investment. And all too often the outcome of this administrative process is shrouded in "black box" settlements, that do not provide the public with transparency about costs they will have to pay. These vestiges of the past need to evolve to ensure that utilities are not seeking excessive profits but only the opportunity to earn the fair rate of return to which they are entitled.

To accomplish this, utilities can prove their need for a requested return on equity by providing a benchmark (representing at least 10% of the incremental requested equity) that is transparently derived through a public process with competitive bidding by multiple participants to establish a fair market cost of that equity. This sample offers the energy consumer and Public Utility Commission real-world evidence of the proper authorized return on equity, an amount that will allow the utility to earn reasonable equity returns under efficient operations. If a utility declines to justify its requested return on equity through a competitive, transparent process, it creates a presumption in the view of my Administration that the requested rate is higher than would have been derived from such a competitive process. Absent extraordinary and unforeseen circumstances, a utility can overcome that presumption by requesting a return on equity that does not exceed the rate of the current 10-year U.S. Treasury yield plus the five-year median of the equity risk premium as published in the Federal Reserve's Financial Stability Reports. In simple terms, this allows the filing utility to earn the same expected return as the stock market as a whole, according to Federal Reserve estimates, comfortably exceeding typical Public Utility Commission calculations of risk for the utility sector.

This provides an outcome that is fair for your utility and your customers even without an auction or other market-based price discovery mechanism.

This letter is an effort to be up front with you about my Administration's approach to rate requests going forward. In directly laying out these practices, I am making clear my expectations. I stand ready to collaborate with you, the Public Utility Commission, and other stakeholders in advancing thoughtful rate requests that put Pennsylvania families and businesses first and control costs after years of unacceptably high rate increases. Should you wish to have my Administration's support for any future rate requests, you must submit a description of your compliance with these practices to my Special Counsel for Energy Affordability alongside your rate case filings.

I appreciate your compliance with these practices and look forward to working together to control costs for ratepayers and build out the needed infrastructure for our Commonwealth.

Sincerely,

Governor Josh Shapiro

Cc: Honorable Stephen M. DeFrank, Chair, Pennsylvania Public Utility Commission
Honorable Kimberly M. Barrow, Vice Chair, Pennsylvania Public Utility Commission
Honorable Kathryn L. Zerfuss, Commissioner, Pennsylvania Public Utility Commission
Honorable John F. Coleman, Commissioner, Pennsylvania Public Utility Commission
Honorable Ralph V. Yanora, Commissioner, Pennsylvania Public Utility Commission
Mark Szybist, Special Counsel for Energy Affordability, Office of General Counsel

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule C-4
Witness: A. M. Keller
Page 1 of 9

I&E Modified

Working Capital

Line No	Description	[1] Fully Projected TYE 9-30-27	[2] Reference
1	Working Capital for O & M Expense	$ 56,298	C-4, Page 2
2	Interest Payments	(9,550)	C-4, Page 7
3	Tax Payment Lag Calculations	4,570	C-4, Page 8
4	Prepaid Expenses	14,400	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 65,718	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2027
($ in Thousands)

Schedule C-4
Witness: A. M. Keller
Page 2 of 9

Summary of Working Capital

I&E Modified

Line #	Description	Reference	[1] Test Year Expenses	[2] Factor	[3] Number of (Lead) / Lag Days [2] * [3]	[4] Totals
	WORKING CAPITAL REQUIREMENT					
1	REVENUE LAG DAYS	Page 3				57.46
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 81,356	12.00	$ 976,269	
4	Purchased Gas Costs	Sch D-6	405,467	26.09	10,576,851	
5	Other Expenses	L 18 - L 3 to L 4	197,533	36.55	7,219,834	
6	Total	Sum (L 3 to L 5)	$ 684,356		$ 18,772,954	
7	O & M Expense Lag Days	L6, C 4 / C 2				27.43
8	Net (Lead) Lag Days	L 1 - L 7				30.03
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,875
10	Working Capital for O & M Expense	L 8 * L 9				$ 56,298
11	Interest Payments	Page 7				(9,550)
12	Tax Payment Lag Calculations	Page 8				4,570
13	Prepaid Expenses	Page 9				14,400
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 65,718
15	Pro Forma O & M Expense		$ 704,715			
	Less:					
16	Uncollectible Expense		20,359			
17	Sub-Total		20,359			
18	Pro Forma Cash O&M Expense		$ 684,356			

I&E Statement No. 2-SR
Witness: Drew Breuning

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Surrebuttal Testimony

of

Drew Breuning

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

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INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Drew Breuning and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME DREW BREUNING WHO SUBMITTED THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) witness Dylan W. D'Ascendis[1] regarding rate of return topics including the cost of common equity

[1] UGI Gas Statement No. 8-R.

and the overall fair rate of return, which will be applied to the Company's rate base.

The absence of any comments or responses to statements or topics addressed in UGI Gas' rebuttal testimony concerning the cost of common equity or the overall rate of return does not imply my acceptance or support of their positions in this proceeding.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. I refer to my direct testimony[2] and schedules contained in my exhibit[3] where necessary.

Q. WHAT WAS YOUR ORIGINAL OVERALL RATE OF RETURN RECOMMENDATION IN DIRECT TESTIMONY?

A. I recommended the following rate of return for the Company:[4]

I&E Summary of Cost of Capital Type of Capital	Ratio	Cost Rate	Weighted Cost
UGI Utilities, Inc. - Gas Division			
Long-Term Debt	45.75%	5.17%	2.37%
Common Equity	54.25%	9.81%	5.32%
Total	100.00%		7.69%

[2] I&E Statement No. 2.
[3] I&E Exhibit No. 2.
[4] I&E Statement No. 2, pp. 6-7 and I&E Exhibit No. 2, Schedule 1.

SUMMARY OF MR. D'ASCENDIS' REBUTTAL TESTIMONY

Q. SUMMARIZE MR. D'ASCENDIS' RESPONSE TO YOUR RATE OF RETURN RECOMMENDATION.

A. First, Mr. D'Ascendis provides an updated analysis from what he employed in his direct testimony. Mr. D'Ascendis disputes my recommendations regarding an overall fair rate of return. While Mr. D'Ascendis takes no issue with my Discounted Cash Flow (DCF) analysis, he criticizes my application of the Capital Asset Pricing Model (CAPM), claiming that I have incorrectly relied on the 10-year Treasury Bond for my risk-free rate, employed Kroll's Equity Risk Premium (ERP), and have not employed the Empirical CAPM (ECAPM). He questions the relevance of recent authorized returns from peers across the country that I presented. Mr. D'Ascendis also takes issue with my dismissal of his Non-Price Regulated Proxy Group and his application of the cost of equity analysis methods. Finally, he claims that I fail to account for UGI Gas' small size-specific risk and disagrees with my exclusion of his flotation cost adjustment to his proposed return on equity.

MR. D'ASCENDIS' UPDATED ANALYSIS

Q. DID THE COMPANY UPDATE ITS RATE OF RETURN CLAIM?

A. Yes. Mr. D'Ascendis provides an updated cost of equity analysis[5] including his gas utility proxy group using data as of March 31, 2026, because his original analysis was performed using data as of October 31, 2025. His updated analysis excludes an additional company (Chesapeake Utilities Corporation) from his proxy group as the company no longer meets his criterion that "a company must have 60% or greater of the respective fiscal year total operating income derived from, or 60% or greater of the respective fiscal year total assets attributable to regulated gas distribution operations."[6] While the results produced by his updated analysis indicate an increased common equity cost rate range, Mr. D'Ascendis continues to recommend a 10.75% return on equity (ROE) as he did in his direct testimony. However, he did use the Company provided updated cost of debt in calculating his overall updated rate of return recommendation as illustrated below:[7]

[5] UGI Gas Statement No. 8-R, pp. 3-5.
[6] UGI Gas Statement No. 8-R, p. 4.
[7] UGI Gas Rebuttal Exhibit B, Schedule DWD 1-R, p. 1.

Company Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	45.75%	5.22%	2.39%
Common Equity	54.25%	10.75%	5.83%
Total	100.00%		8.22%

Q. DO YOU HAVE ANY UPDATES TO YOUR RATE OF RETURN ANALYSIS AND RECOMMENDATION?

A. Yes. I have updated my overall rate of return recommendation to include the Company's updated cost of long-term debt. My recommended capital structure and cost of equity remain the same as presented in my direct testimony and shown below:

I&E Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	45.75%	5.22%	2.39%
Common Equity	54.25%	9.81%	5.32%
Total	100.00%		7.71%

CAPITAL ASSET PRICING MODEL

Q. SUMMARIZE MR. D'ASCENDIS' RESPONSE TO YOUR CAPM ANALYSIS.

A. Mr. D'Ascendis disputes my use of the 10-year U.S. Treasury Note as a proxy to measure the risk-free rate that I use in my CAPM analysis.[8] He also disagrees with my use of Kroll's MRP (Market Risk Premium, also identified as the Equity Risk Premium or ERP by Kroll and I&E)[9] and my exclusion of the ECAPM method of computing the Company's return on equity.[10]

RISK-FREE RATE

Q. WHAT IS MR. D'ASCENDIS' RESPONSE TO YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE?

A. Mr. D'Ascendis claims his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Note because it better reflects the life of the underlying investment. He opines that long-term treasury notes are not subject to maturity risk as the cost of equity is a long-term concept, and the investment horizon of an individual investor is irrelevant. He also claims that not incorporating the longest projection available is inconsistent with the DCF assumption of a constant rate of dividend growth and the Efficient Market Hypothesis (EMH), which assumes that all available information is

[8] UGI Gas Statement No. 8-R, pp. 25-27.
[9] UGI Gas Statement No. 8-R, pp. 27-29.
[10] UGI Gas Statement No. 8-R, pp. 30-34.

considered by investors. Finally, he asserts that my use of a medium-term (10-year) Treasury Note does not match the life of the assets being valued.[11]

Q. IS THE LIFE OF THE INVESTMENT THE ONLY FACTOR THAT SHOULD BE CONSIDERED IN THE CHOICE OF A RISK-FREE RATE?

A. No. The risk-free rate is the return that can be earned without accepting any risk, and while the life of the investment can be considered in the choice of risk-free rates, the most important consideration is that the rate be as risk-free as possible. As explained in my direct testimony,[12] I chose the 10-year Treasury Note as it mitigates the shortcomings of the short-term Treasury Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is appropriate. Further, as also pointed out in my direct testimony, the Commission has historically agreed with I&E that the 10-year Treasury Note is the superior measure of the risk-free rate of return.[13] Finally, I disagree with Mr. D'Ascendis' statement that the cost of equity is a long-term concept and that the investment horizon of an individual investor is irrelevant. I believe an investor does not invest funds in perpetuity.

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[11] UGI Gas Statement No. 8-R, pp. 24-25.
[12] I&E Statement No. 2, pp. 32-33.
[13] *Pa. PUC v. UGI Utilities, Inc. - Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99.

Rather, an investor is interested in total return on investment over a certain period. If an investor finds a better alternative investment opportunity or needs money for other purposes, they will switch or redeem their equity investment.

Q. DO YOU AGREE WITH MR. D'ASCENDIS THAT LONG-TERM TREASURY BONDS DO NOT HAVE MATURITY RISK?

A. No. As discussed in my direct testimony, while long-term Treasury Bonds exhibit more stability, they are not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation and/or increasing interest rates resulting in reduced purchasing power of the initial investment. This is why long-term treasuries normally offer higher yields to compensate investors for these risks.

<u>KROLL ERP</u>

Q. SUMMARIZE MR. D'ASCENDIS' REBUTTAL TESTIMONY REGARDING YOUR USE OF THE KROLL ERP IN YOUR CAPM ANALYSIS.

A. Mr. D'Ascendis opines that the Kroll ERP contains unpredictable forecasts and is, therefore, of little value. He also argues that Kroll's calculated ERP lacks transparency of data and contends that Kroll's ERP is a less effective method

when compared to other methods, stating that Kroll is a "simplistic and opaque MRP forecast."[14]

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS' REBUTTAL TESTIMONY CONCERNING THE KROLL ERP?

A. As discussed in my direct testimony, I provided two CAPM analyses (one of which includes the Kroll ERP) as the CAPM does provide some value and the Commission has recently relied upon a combination of both the DCF and CAPM models. My inclusion of the Kroll ERP in my CAPM analysis is to provide more information to the Commission as it has recently expressed increasing interest in the CAPM model. Kroll is a trusted and publicly available source that bases its recommended ERP on current and forecasted economic and financial conditions.[15]

As a side note, Mr. D'Ascendis' opposition to my use of Kroll's ERP further demonstrates that the inputs to the CAPM are highly subjective and can lead to significantly different results. This is not the case with the DCF model.

[14] UGI Gas Statement No. 8-R, pp. 27-29.
[15] I&E Statement No. 2, pp. 35-36.

EXCLUSION OF THE ECAPM

Q. PLEASE SUMMARIZE MR. D'ASCENDIS' RESPONSE TO YOUR EXCLUSION OF THE ECAPM IN YOUR ANALYSIS.

A. Mr. D'Ascendis asserts that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the CAPM model predicts, that tests of the CAPM have measured the extent to which security returns, and that betas are related as predicted by the CAPM that confirms its validity. Thus, he asserts ECAPM should be used in the CAPM analysis.[16]

Q. WHY IS THE ECAPM EXCLUDED FROM YOUR ANALYSIS?

A. The ECAPM is a modified version of the CAPM which attempts to address the belief that the actual risk vs. return correlation is flatter than what is predicted by the CAPM. The implication is that the CAPM underestimates returns with lower levels of risk and overestimates the returns associated with higher levels of risk. The model entails assigning a 25% weight to the market beta and a 75% weight to the individual company or proxy group.[17]

Additionally, the use of the ECAPM in estimating the cost of capital does not increase the validity of the result but merely adds another measure of subjectivity to the CAPM in an attempt to make the SML more accurate. The

[16] UGI Gas Statement No. 8-R, pp. 30-34.
[17] David C. Parcell, "The Cost of Capital - A Practitioner's Guide," 2020 Edition, p. 106.

ECAPM reduces the purpose of the beta, which is the only company-specific variable in the CAPM model.

Lastly, I am unaware of any cases where the Commission has specifically recognized or relied upon ECAPM results in a cost of equity determination.

Q. ARE YOU CHANGING YOUR CAPM RETURN ON EQUITY RECOMMENDATION AS A RESULT OF MR. D'ASCENDIS' REBUTTAL TESTIMONY?

A. No. I continue to recommend using my traditional CAPM result of 9.95% and CAPM result using Kroll's ERP of 8.55% (with an average of both CAPM results of 9.25%).[18]

NATIONAL AVERAGE AUTHORIZED ROE

Q. SUMMARIZE MR. D'ASCENDIS' CRITICISM OF YOUR USE OF NATIONAL AVERAGE AUTHORIZED ROEs IN DETERMINING YOUR RECOMMENED RETURN ON EQUITY FOR THE COMPANY.

A. Mr. D'Ascendis claims that authorized ROEs are reasonable benchmarks of an appropriate ROE in a static economy, but mis-specify the returns required by investors in a dynamic economic environment. He also states that "historical authorized returns do not completely reflect the investor required return because

[18] I&E Exhibit No. 2, Schedule 18.

the economic conditions in the past are not representative of economic conditions now."[19] Therefore, Mr. D'Ascendis argues that historically allowed ROEs are of little value.[20]

Q. PLEASE RESPOND TO MR. D'ASCENDIS' CRITICISM REGARDING YOUR USE OF NATIONAL AVERAGE AUTHORIZED ROEs IN DETERMINING AN APPROPRIATE ROE IN THIS PROCEEDING.

A. While I agree with Mr. D'Ascendis that historical returns are not entirely predictive of required future returns, I continue to believe it is reasonable and logical to consider authorized returns of comparable companies in the natural gas distribution industry from across the nation. Additionally, I believe the current economic conditions are similar enough to the past approximate year and a half, which is the period that encompasses the data I employed.[21] Finally, as stated in my direct testimony, this information complies with the principle derived from the *Hope* and *Bluefield* cases,[22] that a utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.[23]

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19 UGI Gas Statement No. 8-R, p. 34.
20 UGI Gas Statement No. 8-R, p. 34.
21 I&E Exhibit No. 2, Schedule 6.
22 *See Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923) and *FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).
23 I&E Statement No. 2, p. 4 and p. 37.

NON-PRICE REGULATED PROXY GROUP

Q. WHAT WAS YOUR RECOMMENDATION IN DIRECT TESTIMONY CONCERNING MR. D'ASCENDIS' USE OF A NON-PRICE REGULATED PROXY GROUP?

A. I recommended that the Commission reject all analyses performed using the non-price regulated company proxy group as it is highly speculative and subjective. Mr. D'Ascendis' non-price regulated proxy group in effect blends the CE approach into the DCF, CAPM, and RP models. I also provided citations to multiple Commission orders supporting my position that the CE method is highly speculative and subjective.[24]

Q. SUMMARIZE MR. D'ASCENDIS' RESPONSE REGARDING YOUR DISAGREEMENT WITH HIS USE OF A NON-PRICE REGULATED PROXY GROUP.

A. In rebuttal testimony, Mr. D'Ascendis attempts to justify the use of the companies in his non-price regulated proxy group based on the unadjusted betas and standard errors of the regression being similar to that of the companies in his gas company proxy group.[25] Therefore, he opines that they are comparable to UGI Gas in the context of total risks (business risk and financial risk). He admits that business risk and financial risk may vary between companies and proxy groups. However,

[24] I&E Statement No. 2, pp. 42-44.
[25] UGI Gas Statement No. 8-R, pp. 20-22.

he claims that if the collective average betas and standard errors of the regression of the proxy group are similar, then the total non-diversifiable market risks and diversifiable risks are similar as noted in an academic article entitled, "Comparable Earnings - New Life for an Old Precept."[26] Finally, he concludes that the results of market models applied to the non-price regulated proxy group are comparable in total risk to his gas utility proxy group, and therefore, should be accepted by the Commission.[27]

Q. HAS MR. D'ASCENDIS PROVEN THAT THE RISKS FACED BY HIS NON-PRICE REGULATED PROXY GROUP ARE SIMILAR TO THAT OF HIS GAS UTILITY PROXY GROUP?

A. No. The risks faced in each industry for the companies used in Mr. D'Ascendis' non-price regulated group differ from the risks faced by his gas utility group. Specifically, the level of competition between non-price regulated companies and monopolies such as utilities, is too difficult a factor to control. Although beta is an indicator of a company's investment risk in relation to the entire stock market, beta is not a quantification of the total investment risk of a given company. Mr. D'Ascendis' unregulated proxy group may have a beta comparable to that of his gas proxy group, but that does not mean the companies face sufficiently similar risks and uncertainties to be used as a substitute for an industry's market. Both

[26] UGI Gas Statement No. 8-R, p. 21.
[27] UGI Gas Statement No. 8-R, p. 22.

beta and the standard error of regression are measures of the past performance of a stock and as such do not necessarily reflect where an industry is going or what risks it is expected to face.

Additionally, the Commission made the following comments in the 2018 UGI Electric base rate proceeding regarding the CE method, specifically for the use of non-utility (unregulated) companies as comparable groups:

> With respect to the CE method, as noted above, this cost of equity method utilizes data for non-regulated firms. Thus, by its very nature, determining which companies are comparable is entirely subjective. In addition, the record indicates that the companies UGI utilized in its CE group results in the selection of companies such as Coca-Cola Company, Kellogg Company, and Walmart Stores, Inc.…Each of these companies operate in industries that are very different from a utility company and have significantly more competition, which would require a higher return for the associated additional risk.[28]

As discussed in my direct testimony,[29] I reiterate that non-price regulated or non-utility companies with unrelated or entirely dissimilar business segments are simply not comparable to gas distribution utilities in terms of business risk and financial risk profiles. Natural gas distribution utilities are monopolies that are subject to very little, if any, competition. Due to this minimal competition, natural gas distribution utilities in general have very low business risk and can maintain higher financial risk profiles by employing more leverage. Conversely, since the

[28] *Pa. PUC v. UGI Utilities, Inc. - Electric Division,* Docket No. R-2017-2640058, p. 105 (Order Entered October 25, 2018). The Commission has also ruled "[t]he use of nonregulated companies as a comparable group for regulated firms requires numerous unsupportable assumptions which results in a highly speculative finding." *Pa. PUC v. Philadelphia Electric Co.*, 33 PUR 4th 319, 341 (Pa PUC 1980).

[29] I&E Statement No. 2, pp. 42-44.

companies in Mr. D'Ascendis' non-price regulated proxy group operate in an unregulated competitive environment with a higher level of business risks and uncertainties, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

Finally, I am advised by counsel that use of a non-price regulated proxy group defies the principle set forth in the *Hope* and *Bluefield* cases[30] that a utility is entitled to a return similar to that being earned by companies with similar risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.

BUSINESS RISK (SIZE) ADJUSTMENT

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING MR. D'ASCENDIS' CLAIM FOR THE COMPANY'S SIZE ADJUSTMENT.

A. In my direct testimony,[31] I discussed how Mr. D'Ascendis' 5-basis point adjustment is unnecessary because none of the technical literature cited in his direct testimony supporting an adjustment related to the size of a company is specific to the utility industry. Additionally, I presented an article by Dr. Annie Wong that demonstrated that there is no need to make an adjustment for the size of a company in utility rate regulation. Finally, I indicated that the Commission has

[30] *See Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923) and *FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[31] I&E Statement No. 2, pp. 44-49.

recently rejected the application of a size adjustment to the cost of equity calculation.

Q. SUMMARIZE MR. D'ASCENDIS' RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE RISK FACTOR ADJUSTMENT.

A. Mr. D'Ascendis opines that smaller companies are simply less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more exposure to business cycles and economic conditions, both nationally and locally.[32] Additionally, he claims that the loss of revenues from a few large customers would have a far greater effect on a small company than on a larger company with a more diverse customer base.[33] He supports these statements by pointing to a study from Fama and French relating the size of a company to its return on equity, which indicates that small capitalization firms are more risky than large capitalization firms.[34] Mr. D'Ascendis also attempts to discredit a study performed by Dr. Wong, that I relied upon in rejecting his size adjustment, by citing a review of her study authored by Thomas M. Zepp.[35] Finally, Mr. D'Ascendis points to a 2019 Commission order in the Citizens' Electric base rate proceeding where he claims that the Commission considered a size adjustment.[36]

[32] UGI Gas Statement No. 8-R, p. 36.
[33] UGI Gas Statement No. 8-R, p. 36.
[34] UGI Gas Statement No. 8-R, p. 36.
[35] UGI Gas Statement No. 8-R, p. 37.
[36] UGI Gas Statement No. 8-R, p. 37.

Q. ARE MR. D'ASCENDIS' ASSERTIONS REGARDING FIRMS OF SMALLER SIZE RELEVANT TO THE REGULATED UTILITY INDUSTRY?

A. No. The study conducted by Dr. Wong provides empirical evidence that refutes Mr. D'Ascendis' claim, which I will further elaborate on below. Furthermore, regulated utility companies have the option to file base rate cases to address declining revenues and to recover the increasing cost of doing business in addition to emergency rate relief provisions for large unforeseen impacts. In contrast, non-utility businesses that may be significantly impacted by events of this nature due to small operating size do not have these opportunities. Further, while a smaller utility may pay higher prices for services and materials simply due to low volume buying power, the actual costs are part of the revenue requirement presented by that company. Thus, increasing the equity return to account for the potential size disadvantage would only further unfairly burden ratepayers who are already likely paying higher utility bills to recover the higher operating costs.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING THE STUDIES MR. D'ASCENDIS RELIES ON TO SUPPORT HIS CLAIM OF A SIZE ADJUSTMENT?

A. The Fama and French study is not specific to the utility industry. While I relied upon the Fama and French study in this proceeding, as Mr. D'Ascendis correctly points out, the purpose for which I cited the study was to empirically demonstrate

the shortcomings of the CAPM. The Fama and French study is irrelevant for the determination of the size risk factor because it is not specific to the utility industry.

Q. PLEASE COMMENT ON THE REVIEW OF DR. WONG'S STUDY PERFORMED BY DR. ZEPP.

A. The article Mr. D'Ascendis references from Dr. Zepp does not recreate Dr. Wong's study; it simply speculates on other possible reasons for Dr. Wong's results and references the results of two other studies. The first study, completed by the California Public Utilities Commission Staff in 1991, is not included in the article, and, therefore, Dr. Zepp's opinions cannot be properly evaluated. Dr. Zepp also draws his conclusions about an entire industry based on the second study, which examines the effects of size on only four water utility companies. This article does not contain enough credible evidence to refute Dr. Wong's findings.

Q. HAVE YOU FOUND FURTHER EVIDENCE TO SUPPORT YOUR RECOMMENDATION REGARDING SIZE ADJUSTMENTS?

A. Yes. The difficulty in predicting the risk effect of a company's size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation: 2015 Yearbook.* As stated on page 100:

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and 10th decile returns was far more substantial. The divergence in the performance of small- and large- cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states:

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states:

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Aswath Damodaran notes in his study "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications" - The 2022 Edition on page 50:

> In the four decades since 1980, the small cap premium has been non-existent, raising questions about whether it still persists or whether it was an artifact of the twentieth century.

Page 51 states:

> Finally, a series of studies have argued that market capitalization, by itself, is not the reason for excess returns but that it is a proxy for other ignored risks such as illiquidity and poor information. The argument that there is, in fact, no small cap premium and that we have

> observed over time is just an artifact of history that should be given credence.

Pages 53-54 state:

> Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is a sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor).

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS' REBUTTAL TESTIMONY REGARDING THE REFERENCED COMMISSION ORDER FOR CITIZENS' ELECTRIC COMPANY?

A. Mr. D'Ascendis admits that the Commission did not make an explicit size adjustment in the Citizens' Electric proceeding, however, he states that the Commission did acknowledge that size is a factor in assessing a company's ability to attract capital. He then claims that the Commission adjusted the DCF result by one standard deviation of the mean and median to account for size.[37] Although the Commission in the Citizens' Electric proceeding agreed that there is an inverse relationship between size and risk, the Commission concluded that there is no substantial evidence that size is specifically a risk for utilities as follows:

> At the same time, however, we echo the ALJs that the Parties have presented offsetting arguments such that there is not substantial evidence to determine whether size is specifically a risk for utilities. As I&E and the OCA both noted, the technical literature presented by Citizens' is not specific to the utility industry and also may not definitively support a size adjustment. Additionally, as I&E observed, the empirical study

[37] UGI Gas Statement No. 8-R, p. 37.

> undertaken by the Company's witness Mr. D'Ascendis illustrates the difficulty in predicting the risk effect of a company's size. More specifically, while Mr. D'Ascendis used market information from the NYSE, the AMEX, and the NASDAQ, we find that I&E offered evidence indicating that for certain periods, large-capitalization stocks have outperformed small-capitalization stocks such that there is not sufficient correlation to prove that size is a specific risk for utilities. I&E St. 2-SR at 23-24. Therefore, we are not persuaded by the Company's argument that the ALJs erred by not awarding Citizens' a greater size adjustment. For this reason, we decline to award an explicit 100-basis point size adjustment, as advocated by Citizens.[38]

Finally, as stated in my direct testimony, the Commission has rejected the application of a size adjustment to the cost of equity calculation.[39] It is important to recognize that utilities, as regulated monopolies, have actions available, such as requests for emergency rate relief, to counter business impacts that would have more adverse results for smaller companies in the private sector. Accordingly, analyses conducted on private sector businesses do not directly translate to the regulated utility industry.

Q. HAS YOUR RECOMMENDATION REGARDING MR. D'ASCENDIS' SIZE ADJUSTMENT CHANGED SINCE YOUR DIRECT TESTIMONY?

A. No. I continue to recommend that any adjustments in consideration of the Company's size be disallowed for the reasons explained above and in my direct testimony.

[38] *Pa. PUC v. Citizens' Electric Company of Lewisburg, PA,* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 103-104.

[39] I&E Statement No. 2, p. 48.

FLOTATION COST ADJUSTMENT

Q. PLEASE SUMMARIZE MR. D'ASCENDIS' REBUTTAL TESTIMONY REGARDING YOUR RECOMMENDATION TO REJECT HIS 12 BASIS POINT FLOTATION COST ADJUSTMENT.

A. Mr. D'Ascendis argues that denying recovery of flotation costs penalizes investors that fund utility operations. He claims that if flotation costs are not recovered, the growth rate and ultimately the ROE fall below the required return. Finally, he cites a case where the Florida Public Service Commission agreed with his methodology and awarded 9 basis points to the authorized ROE.[40]

Q. WHAT IS YOUR RESPONSE TO MR. D'ASCENDIS' REBUTTAL TESTIMONY REGARDING A FLOTATION COST ADJUSTMENT?

A. As discussed in my direct testimony,[41] I reiterate that (1) the flotation costs of the parent company are accounted for and recovered as operating and maintenance expenses or amortized over a certain period in the books of the issuer company; (2) UGI Gas does not issue stocks to the general public in the capital market, the parent company issues stocks for a variety of reasons and uses, and they are not entirely issued and used for the benefit of UGI Gas; and (3) there is no indication that UGI Gas' parent company will issue new stocks during the fully projected future test year (FPFTY) when the new rates will be effective. Further, Mr.

[40] UGI Gas Statement No. 8-R, pp. 38-39.
[41] I&E Statement No. 2, pp. 49-52.

D'Ascendis' claim for the potential flotation cost impact of 0.12% in recommending an ROE of 10.75% for the FPFTY is improper and unsupported, when the implied claim for such cost is based on the historical flotation cost of the parent company, which could be characterized as retroactive cost recovery.

OVERALL RATE OF RETURN

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOUR DIRECT TESTIMONY?

A. Yes. As explained above, while my return on equity and capital structure recommendations remain unchanged, I have updated my overall rate of return recommendation to incorporate the Company's updated cost of long-term debt.

Q. PLEASE RESTATE YOUR UPDATED RATE OF RETURN RECOMMENDATION?

A. I recommend the following updated rate of return for the Company:[42]

I&E Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	45.75%	5.22%	2.39%
Common Equity	54.25%	9.81%	5.32%
Total	100.00%		7.71%

[42] I&E Statement No. 2, pp. 6-7.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING YOUR RETURN ON EQUITY AND OVERALL RATE OF RETURN ANALYSIS?

A. Yes. There have been current concerns regarding utility bill affordability as addressed in various statements by Commissioner Barrow[43] and concerns raised by Governor Shapiro in a recently issued letter to Pennsylvania Utility Leaders regarding higher utility costs and enormous profits earned by utilities in 2024.[44] These concerns highlight the importance of ratepayers only being required to pay rates to fund costs that are necessary for the safe and reliable provision of natural gas service. I believe that my recommendations allow the Company to earn a fair return while considering the cost to ratepayers. Given the current economic climate, it is important that ratepayers only be required to pay rates to fund costs that are absolutely necessary for the safe and reliable provision of natural gas service.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

[43] I&E Exhibit No. 2, Schedules 4 and 5.
[44] I&E Exhibit No. 1-SR, Schedule 2, pp. 1-4.

I&E Statement No. 3-SR
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Surrebuttal Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Present Rate Revenue
Weather Normalization Adjustment
Scale Back of Rates

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ethan H. Cline. My business address is 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Valuation Engineer.

Q. ARE YOU THE SAME ETHAN H. CLINE THAT SUBMITTED I&E STATEMENT NO. 3 AND I&E EXHIBIT NO. 3?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to make corrections to my direct testimony and address the rebuttal testimony of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) witnesses Vicky A. Schappell,[1] Sherry A. Epler,[2] and John D. Taylor.[3]

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1 UGI Gas Statement No. 7-R.
2 UGI Gas Statement No. 10-R.
3 UGI Gas Statement No. 11-R.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. No.

FPFTY REPORTING REQUIREMENTS

Q. DID YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT UGI GAS PROJECTS TO BE IN SERVICE DURING THE FUTURE TEST YEAR (FTY) ENDING SEPTEMBER 30, 2026, AND THE FULLY PROJECTED FUTURE TEST YEAR (FPFTY) ENDING SEPTEMBER 30, 2027?

A. Yes. I recommended that the Company be required to provide I&E, the Office of Consumer Advocate (OCA), and the Office of Small Business Advocate (OSBA) with an update to UGI Exhibit A - FTY, Schedule C-2 no later than February 1, 2027, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending September 30, 2026. An additional update to UGI Exhibit A - FPFTY, Schedule C-2 should be provided for actuals through September 30, 2027, no later than February 1, 2028.[4]

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. The Company agreed to provide the requested reports.[5]

[4] I&E Statement No. 3, p. 4.
[5] UGI Gas Statement No. 7-R, p. 2.

PRESENT RATE REVENUE

Q. WHAT DID YOU RECOMMEND REGARDING UGI GAS' CLAIM FOR PRESENT RATE REVENUE?

A. I recommended an increase of $464,481 in present rate revenues from $1,234,682,277 to $1,235,146,758. My recommendation is based on adjustments to UGI Gas' claimed $794,637,988 of residential present rate revenue in the FPFTY.[6]

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. The Company stated that, despite disagreeing with the basis for my adjustment and reserving the right to propose similar use per customer adjustments in future base rate cases, it will accept my adjustment in this case.[7]

WEATHER NORMALIZATION ADJUSTMENT (WNA)

Q. DID YOU RECOMMEND ANY CHANGES TO THE WNA PILOT AS PROPOSED BY THE COMPANY?

A. Yes. I recommended that the 3% deadband be increased to 5% consistent with the Commission's Order in the recent Columbia Gas of Pennsylvania, Inc. (Columbia) base rate case.[8]

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6 I&E Statement No. 3, p. 6.
7 UGI Gas Statement No. 10-R, p. 2.
8 I&E Statement No. 3, p. 15.

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Taylor claimed that my reliance on the Columbia Order regarding the 5% deadband is misplaced because the Commission's determinants regarding WNA design are necessarily utility-specific and fact-dependent. He further claims that increasing the deadband to 5% would materially weaken the WNA by expanding the range of weather variations for which no adjustment is made.[9]

Q. DO YOU AGREE THAT COMMISSION DECISIONS ARE UTILITY-SPECIFIC AND FACT-DEPENDENT?

A. Generally, yes. However, it is also true that Commission Orders set important precedent for future base rate cases. Mr. Taylor himself cites a previous Commission Order in his rebuttal testimony to support his preferred cost of service study methodology in this case.[10] Concerning the WNA, the Commission Order in the Columbia Gas case that increased Columbia's WNA to 5% stated that "a 5% deadband adequately captures what could be considered normal weather fluctuations in Pennsylvania."[11] Mr. Taylor did not provide any evidence that UGI Gas' service territory encounters weather patterns outside of what could be considered normal weather in Pennsylvania.

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[9] UGI Gas Statement No. 11-R, pp. 45-46.

[10] In UGI Gas Statement No. 11-R, pp. 15-16, Mr. Taylor cited the Commission's Order in the 2020 PECO Energy Company – Gas Division base rate case in support of the Average and Excess cost of service methodology.

[11] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, pp. 301-02 (Order Entered December 4, 2025).

Regarding Mr. Taylor's claim that increasing the deadband would reduce the effectiveness of the WNA, the Commission's statement that a 5% deadband "places more of the burden for calculating and forecasting weather variations back onto the Company as a normal part of doing business"[12] illustrates that reducing the effectiveness of the WNA is an acceptable result.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION REGARDING THE WNA?

A. No. I continue to recommend the deadband be increased from 3% to 5%.

SCALE BACK OF RATES

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND?

A. I recommended that the customer charge and usage rates that are proposed to increase be scaled back such that increases for each customer class are scaled back proportionally to the increase originally proposed by UGI Gas based on the cost of service study that is ultimately approved by the Commission. Additionally, because the customer charges and usage rates for the XD and Interruptible classes were not increased under proposed rates, they should not be included in any scale back.[13]

[12] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, pp. 301-02 (Order Entered December 4, 2025).

[13] I&E Statement No. 3, pp. 17-18.

Q. DID THE COMPANY RESPOND TO YOUR SCALE BACK RECOMMENDATION?

A. Yes. UGI Gas witness Taylor opposed my recommendation because "[s]caling back the customer charge merely to match a reduced revenue requirement would disconnect the rate design from cost causation principles and potentially results in an under-recovery of fixed costs."[14] Mr. Taylor also cited NARUC's gas design manual's statement that "[i]deally, the customer charge should recover all customer costs."[15]

Q. PLEASE RESPOND TO MR. TAYLOR'S TESTIMONY REGARDING INCLUDING THE CUSTOMER CHARGE IN THE SCALE BACK OF RATES.

A. A delicate balance exists in rate design between the revenue stability and fixed cost recovery (the Company) and affordability and conservation efforts (customers). I believe that including the customer charge in the scale back of rates is an effective means of recognizing the interests of both the Company and customers. Therefore, I continue to recommend the customer charges that receive an increase be included in any scale back of rates.

[14] UGI Gas Statement No. 11-R, p. 29.
[15] UGI Gas Statement No. 11-R, p. 29.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 4-SR
Witness: Anna L. Ritchie

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2025-3059523

Surrebuttal Testimony

of

Anna L. Ritchie

Bureau of Investigation & Enforcement

Concerning:

PIPELINE REPLACEMENT COSTS
METHANE DETECTOR PILOT PROGRAM

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Anna L. Ritchie. I am a Civil Engineer in the Pipeline Safety Division of the Pennsylvania Public Utility Commission's (Commission) Bureau of Investigation and Enforcement (I&E). My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME ANNA L. RITCHIE WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 4 AND THE SCHEDULES IN I&E EXHIBIT NO. 4?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made by UGI Utilities, Inc. – Gas Division's (UGI Gas or Company) witness Jill E. Walter in her rebuttal testimony[1] regarding the Company's pipeline replacement/restoration costs associated with the replacement of mains, and the continued implementation of the pilot program for a methane detection system in UGI Gas' service territory.

[1] UGI Gas Statement No. 3-R.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. No.

Q. SUMMARIZE MS. WALTER'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RECOMMENDATIONS MADE IN DIRECT TESTIMONY.

A. Ms. Walter agrees restoration costs associated with replacing/retiring natural gas mains has increased over the lifetime of the Company's accelerated main replacement program within its Long-Term Infrastructure Improvement Plan (LTIIP).[2] Ms. Walter states the Paving & Restoration team engage with municipalities to establish cost-share agreements and also negotiate and contest permit fees.[3] Ms. Walter states that Americans with Disabilities Act (ADA) ramp requirements have significantly increased the restoration costs. [4] Regarding the smart remote methane detectors (SRMDs), Ms. Walter states that UGI Gas does not agree with the recommendations made by the Commission. [5]

<u>RESTORATION COSTS</u>

Q. WHAT OTHER FACTORS DOES MS. WALTER STATE HAVE CONTRIBUTED TO THE INCREASING RESTORATION COSTS?

A. Ms. Walter states that the installation of ADA ramps has caused a significant

[2] UGI Gas Statement No. 3-R, p. 3.
[3] UGI Gas Statement No. 3-R, p. 3.
[4] UGI Gas Statement No. 3-R, p. 4.
[5] UGI Gas Statement No. 3-R, p. 6.

increase in costs during the restoration phase of projects.[6] Not only is UGI Gas responsible for replacing ADA ramps to each intersection where UGI Gas replaced or added a gas main, the restoration of the ADA ramps occasionally includes upgrading traffic signals, pedestrian crossings, and installing ADA ramps where no ramps previously existed.[7] UGI Gas took a sample of ten restoration projects completed in Allentown with roughly the same restoration cost of $1.34 million, and of that $1.34 million, UGI Gas states approximately $815,000 (~61% of total paving costs) was related to ADA ramps. [8]

Q. DO YOU THINK THE TEN RESTORATION PROJECTS ANALYZED IN ALLENTOWN ARE REPRESENTATIVE OF UGI GAS' RESTORATION PROJECTS AS A WHOLE?

A. No. The sample size of restoration projects only represents UGI Gas' Allentown territory. UGI should expand their analysis to the other service territories to provide an accurate representation of the Company as a whole. Limiting the sample size to Allentown does not give an accurate description for all of UGI's restoration projects.

[6] UGI Gas Statement No. 3-R, p. 4.
[7] UGI Gas Statement No. 3-R, p. 4.
[8] UGI Gas Statement No. 3-R, p. 4.

METHANE DETECTION

Q. WHAT SUGGESTIONS DID UGI GAS PROPOSE REGARDING THE DEPLOYMENT OF SMART REMOTE METHANE DETECTORS?

A. Ms. Walter stated that UGI Gas does not agree with expanding the deployment of smart remote methane detectors at this time. [9] She also stated that a quarterly findings report is too frequent to show meaningful progress between reports and instead supports annual reporting along with a final report at the end of the pilot program. [10]

Q. DO YOU AGREE WITH MS. WALTER'S STATEMENT THAT QUARTERLY FINDINGS REPORTS ARE TOO FREQUENT?

A. No. Quarterly findings reports will show that UGI Gas is progressively distributing methane detectors to their customers. The quarterly report will give the Commission insight into the number of remote methane detectors (RMDs) and smart remote methane detectors (SRMDs) that have been distributed over the three-month period, the total number of methane detectors distributed, expenses incurred to date, and information on location, service territory, and cause of alarm once the methane detector is in use.

[9] UGI Gas Statement No. 3-R, p. 7.
[10] UGI Gas Statement No. 3-R, p. 6.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS FOR EXPANDING UGI GAS' METHANE DETECTOR PILOT PROGRAM?

A. Yes. I recommend that UGI Gas continue to expand its remote methane detector (RMD) pilot program by identifying areas that are prone to leaks, high risk pipeline areas, buildings or homes, businesses, and places of congregation with inside meter sets and regulators, and to place RMDs units within these high-risk areas first. To effectuate the expansion of the pilot program, I recommend that the pilot program be increased to require installation of an additional 1,000 RMD units during the pilot time frame for a total of 1,500. Further, I recommend that UGI Gas continue to expand the program until every gas customer has an RMD unit. UGI should continue to file the Methane Detector Reporting Spreadsheet quarterly throughout the expansion and continuation of the program.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION OF
ZACHARI WALKER

I, Zachari Walker, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 1 in both Proprietary and Non-Proprietary format
- I&E Exhibit No. 1 in both Proprietary and Non-Proprietary format
- I&E Statement No. 1-SR in both Proprietary and Non-Proprietary format
- I&E Exhibit No. 1-SR in both Proprietary and Non-Proprietary format

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Zachari Walker
Zachari Walker
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: May 27, 2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION OF
DREW BREUNING

I, Drew Breuning, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 2
- I&E Exhibit No. 2
- I&E Statement No. 2-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Drew Breuning
Drew Breuning
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: 05/27/2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION OF
ETHAN H. CLINE

I, Ethan H. Cline, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 3
- I&E Exhibit No. 3
- I&E Statement No. 3-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Ethan H. Cline
Ethan H. Cline
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: 5/27/2026

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION OF
ANNA RITCHIE

I, Anna Ritchie, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents identified as:

- I&E Statement No. 4
- I&E Exhibit No. 4
- I&E Statement No. 4-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an evidentiary hearing in this matter. This Verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Anna L Ritchie

Anna Ritchie
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: 05/27/26

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, et al	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

DIRECT TESTIMONY
OF CHRISTOPHER REYES
ON BEHALF OF
THE RETAIL ENERGY SUPPLY ASSOCIATION

TOPICS:

1) Compliance with Rate Case Settlement
2) Daily Imbalance Trading
3) No-Notice Service Fee
4) Penalties
5) *Force Majeure*
6) Standards of Conduct

RESA Statement No. 1
April 13, 2026

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Christopher Reyes, and I am the Director of Regional Natural Gas Operations for NRG Energy, Inc. ("NRG"). My business address is 804 Carnegie Center Dr., Princeton, New Jersey 08540.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have worked in the Oil & Gas industry in positions of increasing responsibility since 1995. Immediately prior to my current position, which began March 2025, I was Sr. Manager, Regional Operations (NY Metro, North East & Mid-Atlantic) and was in that position since January 5, 2021 when NRG completed the acquisition of Direct Energy from Centrica PLC, I held the same title and fulfilled the same responsibilities with Direct Energy dating back to June 2017. Before that, I was Sr. Natural Gas Trader for Direct Energy from January 2014 until June 2017. Prior to joining Direct Energy, I was with Hess Corporation, where I worked for over 18 years in various positions, including Sr. Natural Gas Trader, Natural Gas Trader and Sr. Wholesale Natural Gas Scheduler. I received a Master of Business Administration from Webster University in Finance in 2001 and a Master of Arts, Business and Organizational Security Management, from Webster University in 2003.

Q. WHAT ARE YOUR KEY RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current role, I am responsible for managing the United States and Canada Regional Natural Gas Operations Teams (Retail Natural Gas Pricing and Scheduling).

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. Yes, I testified in UGI's most recent two rate cases at Docket Nos R-2024-3052716 and R-2021-3030218.

Q. ON WHOSE BEHALF IS THIS DIRECT TESTIMONY OFFERED?

A. This Direct Testimony is offered on behalf of The Retail Energy Supply Association, also known as RESA. RESA, is an organization that represents competitive energy providers including natural gas suppliers ("NGSs").[1]

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to offer RESA's perspectives on specific aspects of Supplement No. 63 to UGI Tariff Gas – Pa. P.U.C. Nos. 7 and 7S filed by UGI Utilities, Inc. – Gas Division ("UGI" or "Company") on January 29, 2026, and to describe both new and ongoing concerns regarding the Company's overall natural gas operations, particularly as they affect the retail natural gas market. Specifically, my Direct Testimony addresses the following issues: (1) UGI's compliance with the settlement in the most recent prior rate case;

[1] The views expressed in this Testimony represent the position of the Retail Energy Supply Association (RESA) as an organization but may not represent the views of any particular member of the Association. Founded in 1990, RESA is a broad and diverse group of retail energy suppliers dedicated to promoting efficient, sustainable and customer-oriented competitive retail energy markets. RESA members operate throughout the United States delivering value-added electricity and natural gas service at retail to residential, commercial and industrial energy customers. More information on RESA can be found at www.resausa.org.

(2) Penalties; (3) Daily Imbalance trades; (4) the rates for No-Notice Service; (5) UGI's affiliates and its interaction with its affiliates; and (6) *force majeure*.

Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS IN EACH OF THESE AREAS?

A. Yes. My recommendations can be summarized as proposing that the Commission:

1. Monitor UGI's compliance with the requirement that it provide notifications of cuts and interruptions to NGSs on weekends and holidays in the same manner as it does for weekdays.
2. Require UGI to implement daily imbalance trading.
3. Reject UGI's proposed rate for No Notice Service and require that UGI implement a cost-based rate for No Notice Service ("NNS").
4. Require UGI to submit a new tariff with penalties at rates no higher than 20% more than the average of all PA NGDCs.
5. That UGI be required to implement a tariffed policy that provides for *force majeure* protections.
6. In its next audit of UGI, the Commission should review UGI's compliance with the standards of conduct, particularly as they pertain to its relationship with its affiliated NGS.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. Below is a table of the exhibits I am sponsoring. All are attached to my Direct Testimony.

Exhibit Name/Number	***Description***	***Page***
CR-1	UGI Response to RESA Set I, No. 9	4

II. OPERATIONAL ISSUES

Q. DO YOU HAVE ANY ONGOING CONCERNS REGARDING OPERATIONAL ISSUES THAT ARE AFFECTING NATURAL GAS SUPPLIER PARTICIPATION IN THE RETAIL MARKET?

A. Yes. UGI's most recent prior rate case was in 2025. In that case I testified that suppliers were experiencing operational issues regarding the lack of timely notifications of cuts in supply, which could occur when a nomination made by an NGS needed to be corrected over a weekend or on a holiday. As part of the Settlement that resolved that rate case, UGI agreed to address this issue within 6 months of the approval of the settlement. That date is fast approaching and UGI only now claims that it made the required changes.[2] It is not clear how that new protocol has been implemented or will work. My point in raising it is to note that the process is now in place and we plan to make sure it complies with the settlement UGI and RESA agreed to.

Q. ARE THERE OTHER OPERATIONAL ISSUES THAT WERE RESOLVED IN THE SETTLEMENT?

A. Yes. UGI agreed to notify suppliers when any of the NGS's interruptible customer's service will be interrupted. These notifications to suppliers were supposed to be at or as close to the notification of the customers as possible to ensure compliance with the interruption directive.

Q. WHY IS THIS SORT OF COMMUNICATION IMPORTANT?

A. Customers are not involved in the actual scheduling of natural gas supply to meet their usage obligations. Suppliers perform all nominations and balancing services on behalf of the

[2] See Exhibit CR-1; UGI's Response to RESA Set I, No. 9.

customer and as such need to have ALL relevant information to ensure compliance with flow directives mandated by the utility. This includes the level of interruption and all relevant information as to the potential minimum/maximum of required deliveries.

Q. HAS UGI MADE THE CHANGES THEY AGREED TO IN THE SETTLEMENT?

A. UGI faltered a bit in December and January, but it appears that they are making headway in implementing this beneficial change. UGI must fully implement the change and make sure that both their schedulers, customer representatives and all others involved in the process of supplying gas to customers know what is required by the 2025 Settlement and both the customer and supplier know when the customer will be interrupted.

III. DAILY IMBALANCE TRADING

Q. WHAT IS AN IMBALANCE?

A. The definition of an imbalance of gas for transportation customers can be considered from two perspectives. First, a customer may consume more gas than the quantity nominated on their behalf, meaning there is not enough gas. Second, a customer may use less gas than the quantity of gas nominated on their behalf, meaning there is too much gas being delivered. In either scenario, the difference is known as an Imbalance. Imbalances are the leading reason that penalties are imposed on suppliers. NGSs must balance forecasted and nominated supply versus actual customer usage, which can vary day-to-day. At times, usage data reporting can be delayed or be inaccurate if there are meter issues or data collection issues. Such delays result in Imbalances can be negative or positive. Either way, the Imbalance can cause the supplier or a customer to be penalized if the imbalance is outside of UGI's allowed tolerance.

Q. IS THERE A SOLUTION TO AVOID IMBALANCES?

A. Yes. Intra-month balancing options, such as daily imbalance trading, can be made available to NGS and customers taking service on UGI's choice and interruptible programs.

Q. HOW DOES IMBALANCE TRADING WORK?

A. Imbalance trading allows for the transfer of specified quantities of gas from one customer or NGS to another customer or NGS during (1) normal operations; (2) when the utility issues an Operational Flow Order ("OFO"); or (3) when there are constraints or interruptions. In concept, imbalance trading is a system that allows suppliers to trade or transfer gas with other NGS's to meet their UGI mandated balancing requirements. For example, if one NGS or customer delivers more than is needed and another NGS or customer delivers less, the two parties can "trade" the imbalance so that both can be closer to or within allowable delivery tolerances.

Q. HOW DO SUCH SYSTEMS WORK, AND DO THEY REQUIRE A SUBSTANTIAL AMOUNT OF INFRASTRUCTURE?

A. Imbalance trading enables NGSs to trade eligible quantities for imbalance trading would not exceed the confirmed deliveries for a specific day. Trading would only occur on confirmed deliveries on the pipeline located within the same market area. These practices would allow UGI to maintain system integrity and provide customers and suppliers with flexibility and a mechanism to meet their UGI mandated balancing requirements while minimizing potential penalty situations. A request would not be accepted by UGI if trading would cause imbalance charges to occur. All requests would be accurately completed and executed by both parties

and submitted electronically to UGI. UGI would not be involved in any arrangement or agreement for compensation for the value of the gas being traded or transferred. The Company's role would be in administering the trade. Little to no infrastructure changes would be necessary. UGI currently manages the monthly imbalance trading programs and the process is virtually the same but on a daily basis.

Q. HOW WOULD CUSTOMERS ON UGI'S SYSTEM BENEFIT FROM IMBALANCE TRADING.

A. All other things equal, imbalance trading would result in lower costs to customers on UGI's system while having no impact on the physical operation of UGS's system. The lack of imbalance trading on UGI's system is an affordability issue that unnecessarily increases costs to customers.

Q. DO OTHER GAS UTILTIY COMPANIES IN PENNSYLVANIA OFFER IMBALANCE TRADING?

A. Yes, both Columbia Gas of Pennsylvania and PECO allow a version of imbalance trading to occur under both monthly and/or daily balancing tariff provisions.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO IMBALANCE TRADING?

A. Considering that imbalances are the number one reason that penalties are imposed, it is essential that suppliers be provided the opportunity to engage in imbalance trading to ensure that 1) the system is in balance and 2) to minimize unnecessary penalties and ultimately reduce

costs to customers. UGI can easily build an imbalance trading capability modeled from an existing program currently deployed by other NGDSs. Importantly, imbalance trading does not relieve shippers of their obligation to deliver gas to UGI. It merely enables the market to more efficiently manage imbalances and reduce unnecessary costs. I recommend that UGI be required to implement a daily imbalance trading program.

IV. NO NOTICE SERVICE

Q. WHAT IS NO NOTICE SERVICE?

A. No Notice Service ("NNS") is a fee-based service that shopping customers can subscribe to that allows customers access to delivered supply that is intended to be used in balancing the customers forecasted usage vs actual usage when the temperatures are colder or warmer than the original forecast or usage otherwise varies significantly. Stated simply, it is a cushion of sorts to adjust for differences in usage versus nominations and does not require that the quantities be nominated in advance.

Q. WHAT IS YOUR CONCERN ABOUT THE SERVICE?

A. I am concerned about the rate UGI is charging for the service. As Ms. Epler testifies, UGI's NNS rate is substantially more than the cost of providing the service. As certain customer advocates noted in prior rate cases, UGI maintains a high NNS rate and uses the proceeds to offset gas costs for default service customers. As a result, NGS customers are subsidizing default service customers.[3]

[3] See UGI St.10 p. 16, where Ms. Epler testifies that present and proposed rate for NNS is 22 cents/mcf; as compared to Exhibit SAE-8, which shows the cost of providing NNS is actually $0.17 cents/mcf, and that the difference is credited to reduce gas costs for default supply customers.

Q. WHAT SOLUTION ARE YOU PROPOSING?

A. I propose that UGI utilize standard cost causation principles and set the NNS rate based on the actual cost to provide the service. UGI should be prohibited from charging shopping customers more to reduce the gas costs for default service customers. Such a scenario creates an unlevel playing field to the disadvantage of competitive supply. When customers evaluate competitive supply offers from an NGS, the inflated cost of NNS could persuade a customer to remain on default service. In short, UGI's NNS rate results in unfair competition.

V. PENALTIES

Q. WHAT ARE THE PENALTIES THAT CONCERN YOU?

A. UGI's imbalance penalties are disproportionate and detrimental to the proper functioning of the competitive market. My primary concern about UGI penalties is that they are premised on the avoidance of arbitrage. The arbitrage that UGI alleges is when an NGS diverts supply intended for customers on the UGI system and instead sells the gas to a buyer willing to pay more, even with penalties included.[4] UGI has never demonstrated that this has ever happened on its system. Because of this, UGI's penalties are too high and apply to too many situations, some of which are outside of the supplier's control. Penalizing an NGS in such circumstances, without any proof that arbitrage is unwarranted.

[4] Pa. PUC v. UGI Utilities, Inc. – Gas Division (2025 Rate Case); Docket No. R-2024-3052716; UGI St. No. 13-R, Rebuttal Testimony of Jesse R. Tyahla, pp. 20-24.

Q. WHAT CAN BE DONE TO ADDRESS YOUR CONCERN?

A. UGI's penalties must be brought into line with the other NGDC's. For example, UGI's non-delivery penalty on a critical day is 10 times the highest price of gas published in Gas Daily for the region. At the same time, other Pennsylvania NGDCs have much less severe penalties as you can see below.

UGI	10 X Gas Daily highest price of the day	1000% of the Gas Daily highest price of gas in the region plus all other applicable costs.
PECO	$75	$75/Dth plus all other costs incurred by PECO
PNG	$15	The payment of a gas cost equal to the highest incremental cost paid by PNG on the date of non-compliance, plus one month's demand charges and/or storage charges and overrun costs incurred by PNG (not to be imposed more frequently than twelve times in any 30 day period), plus all other charges incurred by PNG on the date of non-compliance, plus, at PNG's discretion, an appropriate penalty charge, not to exceed $15/Mcf
CPA Choice	$46.60	$46.60 per DTH plus all other charges or costs incurred because of failure to deliver
CPA GTS	1.5 X Gas Daily	The penalty will be equal to 150% times the highest of the Gas Daily Average based on the pipeline scheduling point applicated indices.
National Fuel PA	$25	The higher of $25 per DTH or the Market Price of gas for that day which will be determined by references in the SNL Natural Gas Index for TCO Pool plus associated variable transportation cost to Distribution's city gate.

Q. ARE ALL OF UGI'S PENALTIES OUT OF THE NORM?

A. For the most part, yes.

Q. WHAT DO YOU PROPOSE AS A REMEDY FOR THIS CONCERN?

A. RESA suggests that the Commission adjust all of UGI's Penalties to the level of penalties to be no more than the next highest NGDC's penalties. What UGI's penalty structure ignores is

that on a critical day, as every other day, suppliers have every incentive to deliver gas for their customers and penalties of such magnitude are unnecessary. Rather, if a supplier does not deliver, in my experience, it is likely as a result of an upstream interstate pipeline issue or failure of a third-party supplier and not the NGS. Similar to UGI, which also relies on third party supply that is delivered through an interstate pipeline, if there is an issue on a interstate pipeline -- an upstream event that interrupts firm service – both UGI and suppliers are impacted, particularly in a *force majeure* situation. In that circumstance, even if the penalty were 100 times the highest price of gas in the region, the supplier would not be able to comply. UGI's wholesale third party suppliers, however, would be able to enjoy the benefits of declaring force majeure (even for UGI supply for NGSs) the NGS would not have the benefit of the force majeure and could be stuck with a 10x penalty. Without a showing of some extreme risk that does not plague other NGDCs, it is unreasonable for UGI to have a penalty structure that is so divergent from its Pennsylvania peers. The Commission should have a standard or set of maximum penalties or some other mechanism to bring some reasonableness to the entire question of penalties. For now, as I did in UGI's last rate case, I suggest that UGI's Penalties be capped at no more than 20% higher than the average of the other NGDC penalties for the same "offense."

VI. FORCE MAJEURE

Q. PLEASE EXPLAIN THE CONCEPT OF FORCE MAJEURE.

A. *Force Majeure* is when there is an event outside of the control of any party, that causes an interruption in service. For purposes here, it would be of the magnitude of an interstate pipeline rupture or the loss of an interstate compressor station on a very cold day (or any day),

which leads to the reduction of flow for firm transportation, a reduction of available transportation through an internal constraint, the curtailment of Firm Transportation and/or the issuance of a Force Majeure by the Interstate Pipeline to Shippers. This event would impact a large number of deliveries. In that case a supplier could rely on *force majeure* to avoid being penalized because no matter what it did, it was not able to get gas to the system.

Q. WOULD UGI RECOGNIZE (ACCEPT) A *FORCE MAJEURE* DECLARED BY AN INTERSTATE PIPELINE THAT IMPACTED AN NGS ?

A. No. Not for NGSs, but they will accept them from other providers of supply to their system.

Q. WHAT ARE YOUR CONCERNS ABOUT UGI'S POLICY AROUND DECLARING *FORCE MAJEURE*?

A. UGI has a policy of not accepting force majeure, and that is the problem, most PA NGDCs do recognize them.

Q. WHAT ARE YOU ASKING FOR IN THIS CASE?

A. That UGI implement a *force majeure* tariff provision that would allow NGSs to declare *force majeure* when there simply is nothing the NGS can do to avoid a documented upstream *force majeure*.

VII. STANDARDS OF CONDUCT

Q. PLEASE DECRIBE THE STANDARDS OF CONDUCT.

A. The Commission has Standards of Conduct that are applicable to natural gas distribution companies ("NGDCs") and NGSs at 52 Pa. Code § 62.142, which contain several key provisions that:

- Prohibit the sharing of NGDC employees who have responsibility for operating the distribution system, including natural gas delivery or billing or metering, as well as those responsible for marketing and customer service, with an affiliated NGS;[5]
- Require an NGDC to reasonably allocate to its affiliated NGS the costs or expenses for general administration or support services provided to its affiliated NGS;[6]
- Obligate an NGDC and its affiliated NGS to maintain separate books and records, and require an NGDC to avoid cross-subsidies, to fully allocate shared facilities between the NGDC function and the affiliated function, and to maintain its accounts and records so that the costs incurred on behalf of an affiliated NGS are clearly identified;[7]
- Prohibit an NGDC from applying a tariff provision in a manner that would give its affiliated NGS preference over other NGSs with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, non-delivery and other services provided to its affiliated NGS.[8]

Q. WHAT IS THE SIGNIFICANCE OF THE COMMISSION'S STANDARDS OF CONDUCT?

A. The significance of the Commission's Standards of Conduct is that UGI's affiliated NGS, UGI Energy Services, LLC ("UGI-ES"), is operating in the retail market as a licensed NGS. I am not aware of any other Pennsylvania NGDC that has an affiliated NGS actively serving

[5] 52 Pa. Code § 62.142(a)(13).
[6] 52 Pa. Code § 62.142(a)(9).
[7] 52 Pa. Code § 62.142(a)(12).
[8] 52 Pa. Code § 62.142(a)(2).

in its service territory. As a licensed NGS, UGI-ES is competing against nonaffiliated NGSs in supplying natural gas services to retail customers in that same service territory. To the extent that UGI is not vigilant about strict adherence to the Standards of Conduct, UGI-ES could have an unfair advantage over nonaffiliated NGSs, which prevents the robust functioning of the competitive retail market. In initiating the proposed rulemaking that led to adoption of the Standards of Conduct, the Commission emphasized the need to "ensure that consumers of natural gas will be able to shop for gas that is marketed on a level playing field for all market participants."[9]

Q. WHAT DO YOU RECOMMEND AS A SOLUTION?

A. I recommend that the Commission ensure that UGI is not "sharing" employees with affiliates that provide competitive services, without exception. Sharing means an employee that provides work product to both UGI and any competitive affiliate such as UGIES during the same one-year period. I am not referring to employees who legitimately transfer from one entity to the other, provided the transfer is not for the purpose of avoiding a violation of the provision in the Standards of Conduct, even though repetitive transfers can lead to the same negative results. Rather, I am referring to employees in any managerial level positions who are shared by both UGI and UGI-ES. Given the importance of the prohibition in the Standards of Conduct against sharing of certain employees between UGI and UGI-ES, and the responsibility the Commission has to oversee the proper functioning of the retail natural gas market, I believe that the affiliate relationship between these entities warrants scrutiny and

[9] *Permanent Standards of Conduct Pursuant to 66 Pa.C.S. §2209(b)*, Docket No. L-00030162 (Proposed Rulemaking Order entered September 23, 2003, at 1).

any further action as may be necessary. The Commission should conduct an audit of UGI to provide a full accounting on the issue of shared employees, within 60 days after the issuance of a final order in this proceeding. The audit should include all employees, along with their titles and job descriptions, who migrate back and forth between UGI and UGI-ES, i.e., are "shared" along with documentation of how their salaries are allocated.

Q. DO YOU HAVE CONCERNS ABOUT UGI'S COMPLIANCE WITH THE PROHIBITION AGAINST GIVING UGI-ES PREFERENCE OVER OTHER NGSS IN THE PROVISION OF SERVICES?

A. Yes. In a discovery request in the last rate case (last year), we asked how UGI ensures compliance with the provision that prohibits an NGDC from giving its affiliated NGS preference over other NGSs with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, non-delivery and other services provided to its affiliated NGS. In response, the Company provided confidential training materials, which I have not reviewed but that I am told merely advise employees of the rules and do not contain any provision for monitoring compliance. Although the materials advise employees of this provision in the Commission's Standards of Conduct, UGI has not indicated how frequently the training materials are provided to employees. UGI has not further explained whether it audits the practices of employees to ensure that all of these requirements are followed. Because RESA members participate in the retail gas market competing against UGI-ES, they believe that additional steps are necessary to consider whether any existing practices are resulting in UGI giving UGI-ES an unfair competitive advantage.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission direct that UGI periodically conduct an internal audit that is designed to review compliance with this provision of the Standards of Conduct and report to the Office of Competitive Market Oversight ("OCMO") on an annual basis all measures it has taken and how it has handled any departures from the requirements that it may uncover during an internal audit. It is my understanding that OCMO was created to oversee competition in the retail natural gas supply market, so as to promote the development of the competitive retail market and address obstacles faced by NGSs participating in this market.[10] Therefore, ensuring that UGI is taking the necessary steps to comply with rules that prohibit the showing of a preference to an NGS affiliate appears to fall squarely under that mission.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony as may be appropriate, and to offer testimony at other stages of this proceeding as appropriate.

[10] https://www.puc.pa.gov/natural-gas/committees-working-groups/natural-gas-office-of-competitive-market oversight-ocmo/.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, et al	:	
	:	
v.	:	Docket No. R-2025-3059523
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY
OF CHRISTOPHER REYES
ON BEHALF OF
THE RETAIL ENERGY SUPPLY ASSOCIATION

RESA Statement No. 1-SR
May 27, 2026

Q. PLEASE STATE YOUR NAME.

A. Christopher Reyes.

Q. ARE YOU THE SAME CHRISTOPHER REYES WHO PROVIDED DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. ON WHOSE BEHALF ARE YOU PROVIDING SURREBUTTAL TESTIMONY?

A. The Retail Energy Supply Association, also known as RESA.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. To respond to the Rebuttal Testimony of two UGI witnesses: Ms. Sherry Epler and Mr. Timothy Angstadt.

Q. PLEASE SUMMARIZE YOUR RESPONSES.

A. **Ms. Epler:** I respond to her refusal to agree that the fee for No Notice Service ("NNS") should be reduced to a cost basis, despite her testimony that the rate is not cost based, and despite the fact that no other witness has suggested, in this case, that her cost-based-rate analysis is incorrect. I also refute Ms. Epler's suggestion that it does not matter that the revenue earned by UGI for this above-cost rate is used to subsidize the gas cost rate, which has the anti-competitive effect of reducing the price to compare for default service customers.

Mr. Angstadt: I address his comments on various issues, including: 1) UGI's compliance with the settlement in last year's rate case; 2) his reaction to my proposal in my Direct

Testimony that UGI be directed to implement daily imbalance trading; 3) UGI's extreme and unwarranted penalties; 4) Mr. Angstadt's unsupported positions regarding UGI's refusal to implement a coherent force majeure tariff provision; and, 5) Mr. Angstadt's remarks on UGI's compliance activity in Standards of Conduct matters.

RESPONSE TO MS. EPLER

Q. WHAT IS NO NOTICE SERVICE?

A. It is a service, as the name suggests, that allows a customer to operate within a range of consumption, plus or minus, that is larger than what is otherwise permitted for its rate class. For this service, the customer is charged a separate fee that allows UGI to provide capacity and gas to balance the customer's consumption.

Q. WHAT WAS THE BASIS FOR YOU RAISING NNS AS AN ISSUE IN THIS CASE?

A. I did not raise it, Ms. Epler raised the issue by pointing out that UGI is charging in excess of $0.22 per Mcf/d of the no notice allowance ("NNA"), which is the extended tolerance bandwidth, and that the cost of the service is $0.17 per Mcf/d. That is a substantial difference. To make it worse, the excess revenue is credited to the gas cost rate which has the effect of reducing default service rates.

Q. WHAT WAS MS. EPLER'S RESPONSE TO YOUR SUGGESTION THAT THE RATE SHOULD BE LOWERED TO THE COST BASIS?

A. She claimed the reason is that the company "has faced opposition" to the cost-based rate by OCA's witness. In prior cases, the OCA had presented another methodology that produced a higher cost of service – a calculation that was not adopted. The potential that such a rate could

be adopted in the future is not a legitimate basis for overcharging customers now. More importantly, there is no party to this case that responded to my argument for lowering the rate to actual cost. There is no good policy reason to subsidize default service by charging shopping customers more, yet that is what is happening and that is what I am proposing to stop.

RESPONSE TO MR. ANGSTADT

Q. WHAT PROVISIONS OF THE SETTLEMENT OF THE LAST CASE DOES MR. ANGSTADT ADDRESS?

A. He addresses the concerns I raised - that it was not at all clear if UGI had implemented the requirement that UGI notify suppliers of cuts or mismatched nominations on holidays and weekends, since UGI already provides such notices on workdays.

Q. DID UGI NOTIFY SUPPLIERS OF THE CHANGE?

A. Not in any form that I saw. It was unclear to me because the industry had not been informed of the changes and we would only know otherwise if we had a cut or mismatch on a weekend or holiday. I appreciate Mr. Angstadt clearing it up but think it would have been appropriate to send some form of notice to suppliers on its system.

Q. WHAT ABOUT THE NOTICE OF CUSTOMER INTERRUPTIONS?

A. Mr. Angstadt admitted that UGI had gotten off to a bad start and that its process had failed on a few occasions in January 2026. He seeks to assure us that UGI has solved the problem and that suppliers and customers are now receiving notice of interruptions. We still have no way of knowing that the system will continue to function.

Q. DOES MR. ANGSTADT AGREE THAT UGI SHOULD IMPLEMENT DAILY IMBALANCE TRADING?

A. No. Instead he insists that UGI has an obligation to impose penalties as a deterrent. He also claims, but does not support, that suppliers that don't exactly match deliveries with usage could expose UGI to penalties with interstate pipelines.

Q. DOES MR. ANGSTADT ADDRESS YOUR CONTENTION THAT IMBALANCES ARE THE CAUSE OF MOST PENALTIES?

A. Yes, Mr. Angstadt acknowledge that imbalances are the cause of most penalties, but claims that because UGI's system is so complex, it could not possibly allow for imbalance trading. He claims that because UGI has pockets where a delivery to one area could not assist if it were traded with a delivery to a different area. He also claims that UGI is not "configured" for daily balancing because UGI's system operates on a monthly level. I find this hard to accept because UGI clearly is able to issue penalties for non-delivery on a daily basis.

Q. DO YOU AGREE WITH MR. ANGSTADT THAT IMBALANCE TRADING WOULD CAUSE FLUCTUATIONS BETWEEN SUPPLY AND DEMAND?

A. No. Imbalance trading does not impact actual flows but rather serves to balance the actual deliveries of two parties, after the fact, so that neither is penalized (or they are penalized less) for over or under deliveries, which is economically efficient. Penalties for their own sake do nothing to deter conduct. Of course, Mr. Angstadt ignores the fact that most utilities that offer daily balancing require that the balanced quantities be deliverable to the same allowed receipt points. Given UGI's punitive penalties, requiring maximum flexibility for suppliers to trade daily imbalances (same receipt zone) amongst themselves, and not allowing for what amounts to an impoundment that benefits the utility on peak pricing days should be mandatory.

Q. WHAT IS MR. ANGSTADT'S REACTION TO YOUR CONTENTION THAT UGI'S PENALTIES ARE EXTREMELY HIGH AND THAT UGI HAS NEVER PROVIDED AN ACTUAL EXAMPLE OF ARBITRAGE TO SUPPORT ITS CONTENTION THAT SUPPLIERS WILL ENGAGE IN ARBITRAGE IN THE ABSENCE OF EXTREME PENALTIES?

A. Mr. Angstadt claims that even though UGI has no evidence that any party ever engaged in the sort of arbitrage it claims could happen, does not mean it could not happen. He accuses suppliers of having incentives to maximize profits, that could push them to leave the very customers that the supplier has spent time and money to sign up, without gas at a critical juncture. He has no factual basis for such belief. He simply claims that UGI is being proactive in preventing the sort of conduct that he describes. Charging a 10 x the highest price in the market as a penalty subjects suppliers to risks that makes operating on the UGI system extremely difficult, and I believe that is at least one reason UGI maintains the penalties that they do. A supplier is incentivized to not have a penalty at any amount above cost because they have no means of recovering the cost of the penalty. Most utilities' penalties are substantially lower than UGI's and they don't have large numbers of penalties. In my experience, if a supplier is penalized – they have tried everything they can do to avoid it. If a supplier is penalized at all it increases its costs and, because penalty revenue reduces gas costs for UGI, it is a double hit, in that the penalty raises the supplier's cost and lowers the price to compare. It is anticompetitive.

Q. WHAT DOES MR. ANGSTADT HAVE TO SAY ABOUT FORCE MAJEURE?

A. That UGI does not have a documented policy with regard to force majeure. Recall that force majeure is, when due to circumstances beyond the control of a party, it cannot perform an obligation. In the case of a supplier, an example would be if the interstate pipeline were to

lose a compressor station on a cold day and need to curtail deliveries, and there were no other gas available at any price; that would be a force majeure event in most circumstances, but not on UGI. I find it ironic that Mr. Angstadt complains that during a recent event that caused several suppliers to declare force majeure despite UGI not having any policy, the suppliers' submissions lacked critical information. That result is not surprising since nowhere does UGI list what information it needs for such a claim.

Q. WHAT SHOULD UGI DO TO FIX THIS ISSUE?

A. UGI should be required to develop a policy that acknowledges that force majeure events do happen and that provides for a means for parties to legitimately claim a force majeure event and what that means in an operational sense using industry standards.

Q. WHAT ARE THE STANDARDS OF CONDUCT FOR UGI?

A. The Commission's Regulations list the Standards of Conduct at 52 Pa. Code § 62.142. The Standards are:

(1) An NGDC shall apply its tariffs in a nondiscriminatory manner to its affiliated NGS and a nonaffiliated NGS.

(2) An NGDC may not apply a tariff provision in a manner that would give its affiliated NGS preference over other NGSs with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, non-delivery and other services provided to its affiliated NGS.

(3) Mandatory tariff provisions may not be waived by an NGDC for an NGS absent prior approval of the Commission.

(4) When a tariff provision is not mandatory or provides for waivers, an NGDC shall grant the waivers without preference to its affiliated NGS or nonaffiliated NGS.

(5) An NGDC shall maintain a chronological log of tariff provisions for which it has granted waivers. Entries must include the name of the party receiving the waiver, the date and time of the request, the specific tariff provision waived and the reason for the waiver. The chronological log must be open for public inspection during normal business hours. When the NGDC maintains a website, it shall post the terms set forth in this paragraph on its website for at least 3 months.

(6) An NGDC shall process requests for distribution services promptly and in a nondiscriminatory fashion with respect to other requests received in the same or a similar period. An NGDC shall maintain a chronological log showing the processing of requests for transportation services. The chronological log must be open for public inspection during normal business hours.

(7) If an NGDC provides a distribution service discount, fee waiver or rebate to its favored customers, or to the favored customers of its affiliated NGS, the NGDC shall offer the same distribution service discount, fee waiver or rebate to other similarly situated customers. Offers may not be tied to an unrelated service, incentive or offer on behalf of either the NGDC or its affiliated NGS. A chronological log shall be maintained showing the date, party, time and rationale for the action. The chronological log must be open for public inspection during normal business hours.

(8) Subject to customer privacy or confidentiality constraints, an NGDC may not disclose, directly or indirectly, any customer proprietary information to its affiliated NGS unless authorized by the customer. To the extent that an NGDC does disclose customer information without customer authorization, it shall first seek the permission of the customer consistent with its tariffs, any contractual obligations it may have to the customer or § 62.78 (relating to privacy of customer information) and, if that customer grants permission, contemporaneously provide this same information to other similarly situated NGSs in a similar fashion so as not to selectively disclose, delay disclosure or give itself or its affiliated NGS an advantage related to the disclosure. A chronological log shall be maintained showing the date, party, time and rationale for the disclosure. The chronological log must be open for public inspection during normal business hours. This paragraph does not apply to the disclosure of customer information made under a customer assistance program mandated by State law or regulation.

(9) An NGDC shall reasonably allocate to its affiliated NGS the costs or expenses for general administration or support services provided to its affiliated NGS.

(10) NGDCs may not condition or tie the provision of a product, service or price agreement by the NGDC, including release of interstate pipeline capacity, to the provision of a product or service by its affiliated NGS.

(11) An NGDC may not give its affiliated NGS preference over a nonaffiliated NGS in the provision of goods and services including processing requests for information, complaints and responses to service interruptions. An NGDC shall provide comparable treatment in its provision of goods and services without regard to a customer's chosen NGS.

(12) An NGDC and its affiliated NGS shall maintain separate books and records. Transactions between the NGDC and its affiliated NGS may not involve cross-subsidies. Shared facilities must be fully and transparently allocated between the NGDC function and the affiliated NGS function. The NGDC accounts and records shall be maintained so that the costs incurred on behalf of an affiliated NGS are clearly identified.

(13) NGDC employees who have responsibility for operating the distribution system, including natural gas delivery or billing and metering, as well as those responsible for marketing and customer service, may not be shared with an affiliated NGS, and their offices shall be physically separated from the offices used by those working for the affiliated NGS. NGDC employees may transfer to an affiliated NGS provided the transfer is not used as a means to circumvent these standards of conduct.

(14) Neither the NGDC nor its affiliated NGS may directly, or by implication, falsely and unfairly represent to a customer, NGS or third party that an advantage may accrue to a party through use of the NGDC's affiliates or subsidiary, such as:

(i) The Commission-regulated services provided by the NGDC are of a superior quality when services are purchased from its affiliated NGS.

(ii) The merchant services for natural gas are being provided by the NGDC when they are in fact being provided by an affiliated NGS.

(iii) The natural gas purchased from a nonaffiliated NGS may not be reliably delivered.

(iv) Natural gas shall be purchased from an affiliated NGS to receive Commission-regulated services.

(15) When an affiliated NGS markets or communicates to the public using the NGDC name or logo, it shall include a legible disclaimer that states that:

(i) The affiliated NGS is not the same company as the NGDC.

(ii) The prices of the affiliated NGS are not regulated by the Commission.

(iii) A customer does not have to buy natural gas or other products from the affiliated NGS to receive the same quality of service from the NGDC.

(16) When an affiliated NGS advertises or communicates verbally through radio or television to the public using the NGDC name or logo, the affiliated NGS shall include at the conclusion of the communication a legible disclaimer that includes all of the disclaimers in paragraph (15)(i)—(iii).

(17) An NGDC may not:
(i) Jointly market or jointly package its Commission-regulated services with the services of an affiliated NGS.
(ii) Offer or provide to its affiliated NGS products or services, including bill inserts in its NGDC bills promoting an affiliated NGS's services or a link from the NGDC's website, unless the NGDC offers or provides these products or services to nonaffiliated NGSs on the same terms and conditions.
(iii) The restrictions in subparagraphs (i) and (ii) do not apply to competitive bid situations.

(18) An NGDC may not offer or sell natural gas commodity or capacity to its affiliated NGS without simultaneously posting the offering electronically on a source generally available to the market or by otherwise making a sufficient offer to the market. The NGDC shall maintain a chronological log of these public disseminations. The chronological log must be open for public inspection during normal business hours.

(19) An NGDC shall establish and file with the Commission complaint procedures for dealing with alleged violations of the standards of conduct, with the exception of paragraph (9), which is exclusively under the purview of the Commission. These procedures shall be developed in consultation with interested parties during consideration of tariffs guided by this section and § 69.191 (relating to general). The Commission may grant an exception to these requirements if warranted by the facts or circumstances.

(20) An NGDC shall keep a chronological log of any complaints filed, excepting those filed to paragraph (9), regarding discriminatory treatment of NGSs. This chronological log must include the date and nature of the complaint and the resolution of the complaint. The chronological log must be open for inspection during normal business hours.

Q. WHAT IS YOUR CONCERN WITH THESE REQUIREMENTS?

A. UGI is the only NGDC in Pennsylvania with an active affiliate serving customers on its system. In my view, that makes for an environment where what may seem like subtle stretching of the rules can become the norm. In this case, Mr. Angstadt suggests that UGI is subject, at this juncture, to an audit that includes reviewing compliance with the above-listed standards. If that is correct, and regardless of whether the Commission's audit reveals any violations, the results of the audit and the methodology used in the audit should be made

public so that the supplier community can be certain that competition is fair. These sorts of published audits are necessary to provide confidence that the rules are being followed.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, but I reserve the right to supplement this testimony as necessary.

OCA St. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, et al.	**:**	
v.	**:**	**Docket No. R-2025-3059523**
UGI Utilities, Inc. – Gas Division	**:**	

DIRECT TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 13, 2026

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APPENDICES

Appendix A:	Discounted Cash Flow Model Theory
Appendix B:	Capital Asset Pricing Model Theory

I. INTRODUCTION

Q. State your name and occupation.

A. My name is David Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting PLLC.

Q. Summarize your educational background and professional experience.

A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the commission, I formed Resolve Utility Consulting PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

[1] Exhibit DJG-1.

Q. Describe the purpose and scope of your testimony in this proceeding.

A. My testimony addresses UGI Utilities, Inc. – Gas Division's ("UGI" or the "Company") proposed rate of return in response to the direct testimony of Company witness Dylan D'Ascendis.

Q. Please describe the organization of your testimony.

A. In the executive summary below, I provide an overview of the cost of capital issues, my recommendations, and my response to the Company's testimony on these issues. In the sections that follow, I discuss the legal standards governing the awarded return issue as well as the general concepts involved in estimating the cost of equity. I discuss the concepts of risk and return. I provide detailed analysis of the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM"), including my results for these models and my responses to Mr. D'Ascendis's results. I also address capital structure, which is a key component to the cost of capital.

II. EXECUTIVE SUMMARY

Q. Please summarize your rate of return recommendation to the Commission.

A. The key points of my testimony are as follows:

- The Commission should reject the Company's proposed return on equity ("ROE") of 10.75% because it is excessive and unsupported. An objective cost of equity analysis shows that the Company's market-based cost of equity is no higher than 8.8%. Based on this cost of equity analysis, I recommend an authorized ROE of 8.8% for UGI.

- In order to promote a fair authorized rate of return, the Commission should also reject UGI's proposed ratemaking capital structure, which consists of 45.75% debt and 54.25% equity (I refer to the rounded figures of 46% and 54% throughout in my testimony). The Company's proposed, equity-rich capital structure consists of much higher amounts of high-cost equity rather than low-cost debt, which contributes to an excessive authorized rate of return. By comparison, UGI's proposed debt ratio is much lower than its parent company's debt ratio, the average rate of the proxy group, and debt ratios observed in comparable industries in the U.S. I propose a ratemaking capital structure for the Company that is equal to the proxy group average, which consists of 51% debt and 49% equity.
- Alternatively, if the Commission accepts the Company's proposed ratemaking capital structure, then UGI's cost of equity estimate under the CAPM (and ultimate authorized ROE) must be mathematically adjusted to account for the fact that UGI has less financial risk than the proxy group average. This mathematical adjustment under the Hamda model shows UGI's cost of equity is only 8.5% under its equity-rich capital structure. Accordingly, if the Commission accepts UGI's low-risk, equity-rich capital structure, then I recommend an authorized ROE of 8.5% for the Company.
- Based on the results of my financial modeling using the DCF and CAPM models, my primary recommendation results in a weighted average authorized rate of return of 6.95%. My alternative recommendation would result in an authorized rate of return of 6.98%.

Q. Please summarize the statement of Vice Chair Barrow filed in this case regarding capital structure.

A. In her statement dated February 19, 2026, Vice Chair Barrow expressed concern regarding UGI's proposed capital structure and its impact to the Company's proposed rate increase. As stated by Vice Chair Barrow:

> I urge the parties to take a critical look at the Company's requested rate of return and return on equity (ROE) as well as the capital structure (common equity ratio and debt capital) to ensure reasonableness. Deviations in each of these items translate into millions of dollars charged to customers of all rate classes. Too often, the relationship between debt and ROE to cost of debt and capital is asserted as a general matter from basic economic principle alone. But, those relationships are not established empirically. That empirical relationship must periodically be re-established. Therefore, I believe a careful and detailed review of UGI's claimed capital structure and ROE is warranted.[2]

Q. Do you share Vice Chair Barrow's concern regarding UGI's proposed capital structure?

A. Yes. UGI's proposed capital structure for ratemaking purposes is entirely unreasonable, and it exacerbates the unwarranted, excessive transfer of wealth from customers to UGI's shareholders. Pursuant to Vice Chair Barrow's guidance, I conducted a critical analysis of UGI's market based cost of equity and based my authorized ROE for UGI on my cost of equity analysis. However, a company's cost of equity and its capital structure are inextricably and mathematically related. Since UGI's proposed debt ratio of 46% is notably less than the proxy group's average debt ratio of 51%, in order for the Company's cost of equity estimate of 8.8% to be accurate (or whichever cost of equity estimate the Commission ultimately adopts), the Commission should impute a capital structure for UGI

[2] Statement of Vice Chair Kimberly Barrow, Feb. 19, 2026.

that is equal to the proxy group average, which consists of 51% debt and 49% equity. Unlike competitive companies, regulated utilities do not have a natural financial incentive to operate with sufficient amounts of low-cost debt in order to minimize capital costs. A regulator standing in the place of competition should ensure the Company's weighted average cost of capital is minimized to its lowest reasonable level. In order to accomplish this, the Commission must impute a ratemaking debt ratio of 51%, which is equal to the proxy group average (in addition to adopting a fair ROE). Taking this approach perfectly re-establishes the empirical relationship between the Company's ratemaking capital structure, its authorized ROE, and ultimately, its approved rates, as instructed in Vice Chair Barrow's statement.

Q. Does the capital structure of UGI's parent company also relate to Vice Chair Barrow's concerns regarding capital structure?

A. Yes. UGI's parent company, UGI Corp., has a long-term debt ratio of 58%, which is significantly higher than the Company's proposed ratemaking debt ratio of only 46%. Since UGI is a wholly owned subsidiary of UGI Corp., the Company's "equity" on its balance sheet is funded by UGI Corp. Since the parent company has a debt ratio of 58%, this means UGI Corp. is using debt to finance the Company's "equity." Since the Company also issues its own debt, this strategy is known as "double leverage." While this arrangement is not problematic among competitive firms, it often results in unfair, excessive returns for regulated utilities to the extent there is not an adjustment made by the regulator. If no adjustment is made, shareholders of the parent company effectively earn a high-cost equity return on low-cost debt. In fact, UGI Corp's earned ROE last year was 15.2%, which is significantly higher than its cost of equity, or even the inflated ROEs

typically authorized by regulators. In order to mitigate the excessive return that would otherwise occur through double leverage, the Commission should impute a capital structure that is equal to the proxy group average. In light of the fact the average proxy debt ratio of 51% is still considerably less than UGI Corp's debt ratio of 58%, my proposed capital structure adjustment is very reasonable.

Q. Please summarize the results of your capital structure analysis.

A. The figure below highlights just how unreasonable UGI's proposed debt ratio really is.

Figure 1:
Capital Structure Analysis Summary

Industry / Company	Debt Ratio
Cable TV Industry	65%
Power Industry	63%
Telecom Services Industry	61%
UGI Parent Company	**58%**
Proxy Group of Utilities	**51%**
Company Proposed	**46%**

Clearly, UGI's proposed debt ratio of 46% is unreasonably low, and has the effect of increasing capital costs and extracting excess funds from customers for the benefit of shareholders, to the extent it is allowed by the Commission. The details of my capital structure analysis are discussed later in my testimony.

Q. Please describe the impact on customer rates resulting from Company's proposed rate of return compared with your recommendations.

A. For my primary recommendation, which is an authorized ROE of 8.8% and a ratemaking capital structure of 51% debt and 49% equity, it would result in a revenue requirement increase of $19.6 million. For my alternative recommendation, which is an authorized ROE of 8.5% and the Company's proposed capital structure, it would result in a revenue requirement increase of $25.9 million.[3]

III. REGULATORY STANDARDS

Q. Discuss the legal standards governing the awarded rate of return on capital investments for regulated utilities.

A. In *Wilcox v. Consolidated Gas Co. of New York*, [4] the Supreme Court first addressed the meaning of a fair rate of return for public utilities. The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[5] Later, in two landmark cases, the Court set forth the standards by which utilities are allowed to earn a return on capital investments. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, [6] the Court held:

> 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 . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and

[3] These estimates do not take into account the OCA's other proposed adjustment. See the direct testimony and exhibits of OCA witness Jennifer Rogers for details regarding the impacts of OCA's adjustments to the revenue requirement.

[4] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[5] *Id*. at 48.

[6] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

> economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[7]

In *Federal Power Commission v. Hope Natural Gas Company*,[8] the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[9]

The cost of capital models I have employed in this case are in accordance with the foregoing legal standards.

Q. Should the awarded rate of return be based on the Company's actual cost of capital?

A. Yes. The *Hope* Court makes it clear that the allowed return should be based on the actual cost of capital. Moreover, the awarded return must also be fair, just, and reasonable under the circumstances of each case. Under the rate base rate of return model, a utility should be allowed to recover all its reasonable expenses, its capital investments through depreciation, and a return on its capital investments sufficient to satisfy the required return of its investors. The "required return" from the investors' perspective is synonymous with the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of return should be based on the actual cost of capital:

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[7] *Id.* at 692-93.

[8] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

[9] *Id.* at 603 (emphasis added).

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[10]

The models I have employed in this case closely estimate the Company's market-based cost of equity. If the Commission sets the awarded return based on my lower, and more reasonable, rate of return, it will comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of return *higher* than the true cost of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to shareholders.

Q. What does this standard mean for determining the awarded return and the cost of capital?

A. It is important to understand that the *awarded* return and the *cost* of capital are different but related concepts. The two concepts are related in that the legal and technical standards encompassing this issue require that the awarded return reflects the true cost of capital. On the other hand, the two concepts are different in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Awarded returns are set through the regulatory process and may be influenced by factors other than objective market drivers. The cost of capital, on the other hand, should be evaluated objectively and be closely tied to economic realities. In other words, the cost of capital is driven by stock prices, dividends,

[10] A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, p. 21 (The MIT Press 1984).

growth rates, and — most importantly — it is driven by risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. Describe the economic impact that occurs when the awarded return strays too far from the U.S. Supreme Court's cost of equity standard.

A. When the awarded ROE is set far above the *cost* of equity, it runs the risk of violating the U.S. Supreme Court's standards that the awarded return should be *based on the cost of capital*.[11] If the Commission were to adopt the Company's position in this case, it would be permitting an excess transfer of wealth from customers to Company shareholders. The Commission should avoid over-insuring shareholder returns at the expense of ratepayers and instead set a return that reflects a fair balance of risk, cost, and consumer protection. Moreover, establishing an awarded return that far exceeds the true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors, like whether or not the other jurisdiction uses an FPFTY, influencing those awarded returns. This is yet another reason why it is crucial for regulators to focus on the target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions. Awarded returns may be

[11] *See Hope Natural Gas Co*., 320 U.S. at 603.

influenced by settlements and other political factors not based on true market conditions. In contrast, the market-based cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors. If regulators rely too heavily on the awarded returns from other jurisdictions, it can create a cycle over time that bears little relation to the market-based cost of equity and a national trend of over-awarding utilities.

IV. GENERAL CONCEPTS AND METHODOLOGY

Q. Discuss your approach to estimating the cost of equity in this case.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. These models are the DCF Model and the CAPM. The specific inputs and calculations for these models are described in more detail below.

Q. Please explain why multiple models are used to estimate the cost of equity.

A. The models used to estimate the cost of equity attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model. By using multiple models, the analyst can compare the results of the models and

look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. Please discuss the benefits of choosing a proxy group of companies in conducting cost of capital analyses.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly-traded company. There are advantages, however, to conducting cost of capital analyses on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly-traded firms, such as stock prices and dividends.

Q. Describe the proxy group you selected in this case.

A. In this case, I chose to use the same utility proxy group that Mr. D'Ascendis used for his analyses. Thus, the difference in our modeling results are due to the different inputs and assumptions used in our modeling, rather than the composition of the proxy group.

V. RISK AND RETURN CONCEPTS

Q. Please discuss the general relationship between risk and return.

A. As discussed above, risk is the most important factor for the Commission to consider when determining the allowed return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will

demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

Q. Discuss the differences between firm-specific risk and market risk.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[12] There are several other types of firm-specific risks, including: (1) "financial risk" — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" — the risk that a firm will default on its debt securities; and (3) "business risk" — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company.

While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[13]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During that year, Enron Corp.'s stock fell from $80 per share and the company filed for bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would have lost the

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[12] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, pp. 62-63 (3rd ed., John Wiley & Sons, Inc. 2012).

[13] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments*, p. 149 (9th ed., McGraw-Hill/Irwin 2013).

entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because her portfolio included 499 other stocks. Each of those stocks, however, would have been affected by various *market* risk factors that occurred that year, including the terrorist attacks on September 11th, which affected all stocks in the market. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

Q. Can investors minimize firm-specific risk through portfolio diversification?

A. Yes. A fundamental concept in finance is that firm-specific risk can be minimized through diversification.[14] If someone irrationally invested all their funds in one firm (such as Enron), they would be exposed to all the firm-specific risk *and* the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can essentially eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification."

There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-specific action that

[14] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, pp. 179-80 (3rd ed., South Western Cengage Learning 2010).

changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[15]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large, diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[16] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

Q. Do investors expect an additional return for assuming firm-specific risks?

A. No. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing:

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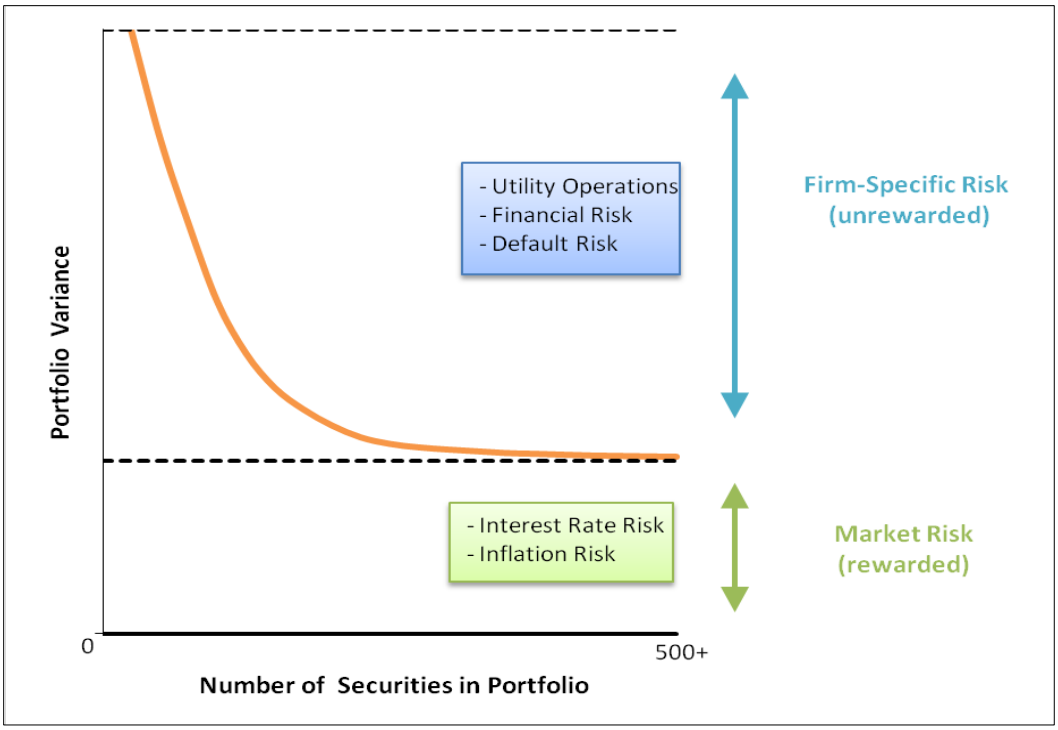
[15] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, p. 64 (3rd ed., John Wiley & Sons, Inc. 2012).

[16] *Id*.

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).[17]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

Figure 2:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus

[17] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 180 (3rd ed., South Western Cengage Learning 2010).

the primary type of risk the Commission should consider when determining the allowed return for the utilities it regulates.

Q. Describe how market risk is measured.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[18] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk, such that if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[19]

Q. Are public utilities characterized as defensive firms that have low betas, low market risk, and are relatively insulated from overall market conditions?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally

[18] *Id*. at 180-81.

[19] Though it will be discussed in more detail later, Exhibit DJG-9 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

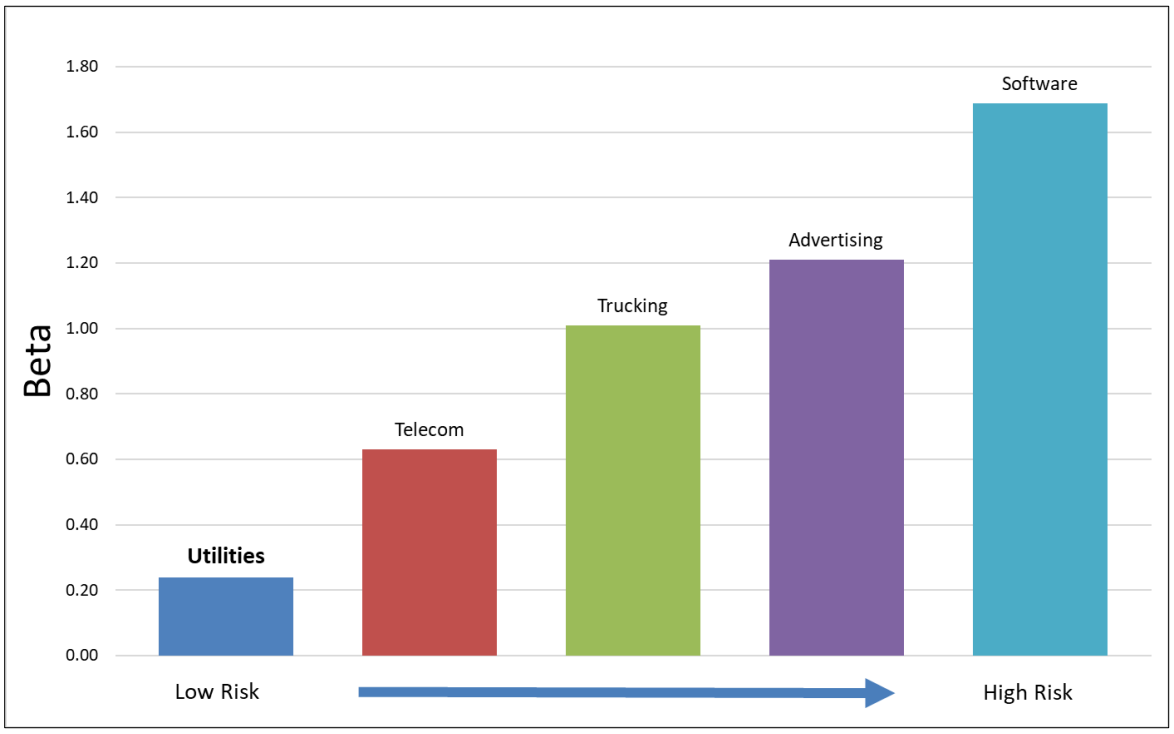
known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[20] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[21] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[22]

[20] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments*, p. 382 (9th ed., McGraw-Hill/Irwin 2013).

[21] *Id*. at 383.

[22] *See* Betas by Sector (US) available at http://pages.stern.nyu.edu/~adamodar/ (2018). (After clicking the link, click "Data" then "Current Data" then "Risk / Discount Rate" from the drop down menu, then "Total Beta by Industry Sector"). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

Figure 3:
Beta by Industry



The fact that utilities are relatively insulated from market conditions should be accurately reflected in the Company's cost of equity estimate.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. Describe the DCF Model.

A. The DCF Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates.[23] Cash flows from common stock are paid to investors in

[23] Present value (PV) is the current value of a future sum of money or stream of cash flows given a specified rate of return. Present value takes the future value and applies a discount rate or the interest rate that could be earned if invested.

the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model, are discussed in more detail in Appendix A.

Q. Describe the inputs to the DCF Model.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

A. Stock Price

Q. How did you determine the stock price input of the DCF Model?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[24] Analysts sometimes rely on average stock prices for longer periods (*e.g.*, 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[25] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend

[24] Exhibit DJG-3.

[25] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance, p. 383 (1970); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 357 (3rd ed., South Western Cengage Learning 2010). The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. Why did you use a 30-day average for the current stock price input?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding, there is a significant length of time between when an application is filed and when testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model that is ultimately used to set rates for several years, especially if a stock is experiencing some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[26]

[26] Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

B. Dividend

Q. Describe how you determined the dividend input of the DCF Model.

A. The dividend term in the DCF Model represents dividends per share (d_0). I used forward-looking annualized dividends published by Yahoo! Finance for the dividend input to my constant growth DCF Model.[27] Dividing these dividends by the stock prices for each proxy company results in the dividend yield for each company.[28]

Q. Are the stock price and dividend inputs for each proxy company a significant issue in this case?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. D'Ascendis, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be conducted on utilities. The differences between my DCF Model and Mr. D'Ascendis's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

C. Growth Rate

Q. Please Summarize the growth rate input in the DCF Model.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input (g) must be estimated. As a result, the growth rate is often the most contentious issue related to DCF model inputs in utility rate cases. The DCF

[27] Exhibit DJG-4.

[28] *Id*.

model used in this case is based on the sustainable growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a sustainable growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a sustainable rate forever. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the sustainable growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet least understood, aspects of cost of equity estimations in utility regulatory proceedings. I provide a more detailed explanation on the various determinants of growth below.

Q. Describe the various determinants of growth that can be considered for the growth rate input in the DCF Model.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on a long-term growth rate in dividends. This is also known as a "sustainable" growth rate, since this is the growth rate assumed for the company's dividends in perpetuity. That is not to say that these growth determinants cannot be considered when estimating sustainable growth; however, as discussed below, sustainable growth must be constrained much more than short-term growth, especially for young firms with high

growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the sources of confusion in this area.

(1) Historical Growth

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are a historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth.

(2) Analyst Growth Rates

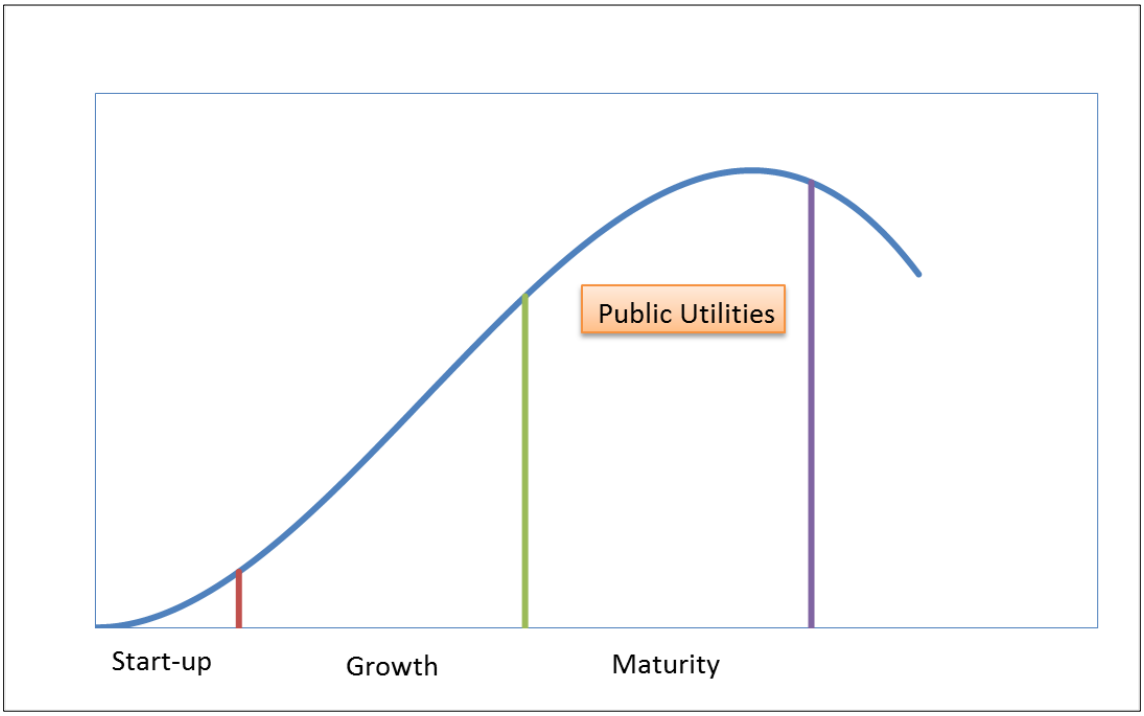
Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. Analyst growth rates, including the limitations with using them in the DCF Model to estimate utility cost of equity, are discussed in more detail below.

(3) Sustainable Growth Rates

In order to make the DCF Model a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being sustainable. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "sustainable," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical

service territories and limited primarily by ratepayer and load growth within those territories. The Figure below illustrates the well-known business/industry life-cycle pattern.

Figure 4:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one sustainable growth rate.

Q. Is the aggregate growth rate of the economy typically a limiting factor for the terminal growth rate in the DCF Model?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[29] Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: "[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[30]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is less than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross Domestic Product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.8%.[31] For mature companies in mature industries, such

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[29] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[30] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012); Aswath Damodaran is a renowned Professor of Finance at NYU Stern School of Business known for his expertise in corporate finance and valuation, teaching MBA students and publishing influential books. He is recognized for transparent teaching, real-time analysis, and making complex finance accessible globally through various platforms.

[31] Congressional Budget Office Long-Term Budget Outlook, https://www.cbo.gov/publication/59014.

as utility companies, the terminal growth rate should not exceed nominal GDP growth. This is the growth rate I used in the sustainable growth variation of my DCF Model.[32]

Q. Did you also consider a variation of the DCF Model that incorporates analysts' growth rate projections?

A. Yes. In this case, I present the results of analyst growth variation of my DCF Model because it is commonly presented in rate proceedings and considered by regulators when assessing a utility's authorized ROE.

Q. Please describe the results of your DCF Models?

A. For my DCF Models, I considered two variations: one using analysts' growth rates and one using the maximum sustainable growth rate. The results of these models are 8.2% and 7.6%, respectively.[33]

D. Response to Mr. D'Ascendis's DCF Model

Q. Please summarize the results of Mr. D'Ascendis's DCF analyses.

A. Mr. D'Ascendis's application of the DCF Model produced an indicated cost of equity result of 10.53%.[34]

Q. Does the result of Mr. D'Ascendis's DCF Model indicate a reasonable cost of equity estimate for UGI?

A. No. Whether the sustainable GDP growth rate or projected dividend growth rates published by Value Line are considered, the highest DCF result I obtained was 8.2%. The primary reason Mr. D'Ascendis's DCF results are overstated is his use of unsustainably high growth

[32] Exhibit DJG-6.

[33] *Id*.

[34] Direct Testimony of Dylan W. D'Ascendis, p. 4, Table 2.

rates for some proxy companies, and average growth rates for the proxy group that are unsustainably high. For example, Mr. D'Ascendis incorporated an annual long-term growth rate as high as 12.66% for Southwest Gas Holdings, Inc. ("SWX"). This means Mr. D'Ascendis is suggesting the company's earnings will grow by more than 12% each year, every year, in perpetuity. This growth rate estimate published by S&P Capital IQ is a short-term growth rate. It is Mr. D'Ascendis, not the commercial analyst, who is suggesting that this annual earnings growth rate can be achieved each year in perpetuity, which is simply unsustainable and technically impossible. As a result, the cost of equity results indicated by Mr. D'Ascendis's DCF Model are overstated.

VII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the CAPM.

A. The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[35] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are discussed further in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of *risk* in the business is a most important factor" in determining the allowed rate of return,[36] and that "the return to the equity owner should

[35] William F. Sharpe, *A Simplified Model for Portfolio Analysis*, pp. 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 208 (3rd ed., South-Western Cengage Learning 2010).

[36] *Wilcox*, 212 U.S. at 48 (emphasis added).

be commensurate with returns on investments in other enterprises having corresponding *risks*."[37] The CAPM is a useful model because it directly considers the amount of risk inherent in a business and directly measures the most important component of a fair rate of return analysis: Risk.

Q. Describe the inputs for the CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is discussed separately below.

A. The Risk-Free Rate

Q. Please explain the risk-free rate.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on an investment. Even though no investment is technically devoid of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. Is it preferable to use the yield on long-term Treasury bonds for the risk-free rate in the CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed

[37] *Hope Natural Gas Co*., 320 U.S. at 603 (emphasis added).

to last indefinitely. As a result, short-term Treasury bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted in a risk-free rate of 4.82%.[38]

B. The Beta Coefficient

Q. How is the beta coefficient used in this model?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater than 1.0 is riskier than the market portfolio. Conversely, a security with a beta less than one is less risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. In contrast, stocks with betas of less than one are less sensitive to market risk.

[38] Exhibit DJG-7.

Q. Describe the source for the betas you used in your CAPM analysis.

A. I used betas recently published by Value Line Investment Survey. The beta for each proxy company is less than 1.0, and the average beta for the total proxy group is only 0.83.[39] Thus, we have an objective measure to prove the well-known concept that utility stocks are less risky than the average stock in the market. While there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line in the interest of reasonableness.[40]

C. The Equity Risk Premium

Q. Describe the equity risk premium.

A. The final term of the CAPM is the equity risk premium ("ERP"), which is the required return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts agree that "the single most important variable for making investment decisions is the equity risk premium."[41] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average;

[39] Exhibit DJG-8.

[40] *See* Appendix B for a more detailed discussion of raw beta calculations and adjustments.

[41] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, p. 4 (Princeton University Press 2002).

(2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. Historical Average

Q. Describe the historical equity risk premium.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. What are the limitations of relying solely on a historical average to estimate the current or forward-looking ERP?

A. Some investors may rely on the historic ERP because it is convenient and easy to calculate. But what matters in the CAPM model is the current and forward-looking risk premium.[42] Some investors may think that a historic ERP provides some indication of what the prospective risk premium is; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually *lower* than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[43] This is due in large part to what is known as "survivorship bias" or "success bias" — a tendency for failed companies to be excluded from historical indices.[44]

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[42] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 330 (3rd ed., South-Western Cengage Learning 2010).

[43] Elroy Dimson, Paul Marsh & Mike Staunton, Triumph of the Optimists: 101 Years of Global Investment Returns, p. 34 (Princeton University Press 2002).

[44] *Id*. at 194.

From their extensive analysis, the authors make the following conclusion regarding the prospective ERP:

> The result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent.[45]

Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[46]

Regardless of the variations in historic ERP estimates, many leading scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[47]

Q. Did you rely on the historical ERP as part of your CAPM analysis in this case?

A. No. Due to the limitations of this approach, I primarily relied on the ERP reported in expert surveys and the implied ERP method discussed below.

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[45] *Id*.

[46] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition*, p. 17 (New York University 2015).

[47] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 330 (3rd ed., South Western Cengage Learning 2010).

2. Expert Surveys

Q. Describe the expert survey approach to estimating the ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers, and other executives around the country and asking them what they think the ERP is. The IESE Business School conducts such a survey each year. Its 2025 expert survey reported an average ERP of 5.5%.[48]

3. Implied Equity Risk Premium

Q. Describe the implied equity risk premium approach.

A. The third method of estimating the ERP is arguably the most accurate. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model that has been widely used in finance for many years.[49] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: The current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Instead of using the dividends of

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[48] Pablo Fernandez, et al., *Survey: Market Risk Premium and Risk-Free Rate used for 54 countries in 2025* (IESE Business School 2024), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=5260463
IESE Business School is the graduate business school of the University of Navarra.

[49] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102-10 (Management Science Vol. 3, No. 1 Oct. 1956); Myron Gordon was an American economist and Professor Emeritus of Finance at the Rotman School of Management, University of Toronto. In 1956, Gordon along with Eli Shapiro, published a method for valuing a stock or business, now known as the Gordon growth model.

a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone, without considering stock buybacks, could understate the cash flow component of the model and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). Equation 1 below shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K, the implied market return.[50]

Equation 1:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

where:

V_{500}	=	*current value of index (S&P 500)*
CY_{1-5}	=	*average cash yield over last five years (includes dividends and buybacks)*
g	=	*compound growth rate in earnings over last five years*
R_F	=	*risk-free rate*
K	=	*implied market return (this is what we are solving for)*
TV	=	*terminal value = CY_5 (1+R_F) / K*

The discount rate is called the "implied" return because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five

[50] *See* Exhibit DJG-9 for detailed calculation.

years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP as shown in the following equation.

Equation 2:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. Discuss the results of your implied ERP calculation.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current required return on the U.S. equity market of 9.8%. I subtracted the risk-free rate to arrive at the implied equity risk premium of 5.0%.[51] Dr. Damodaran, one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. He calculates monthly and annual implied ERPs with this method and publishes his results. Dr. Damodaran's average ERP estimate for March of 2026 using several implied ERP variations was 5.0%.[52]

[51] *Id*.

[52] *See* monthly ERP estimates published by Dr. Damodaran at http://pages.stern.nyu.edu/~adamodar/

Q. Did you also consider the ERP estimate published by Kroll?

A. Yes. Kroll (formerly Duff & Phelps), is a multinational financial and risk advisory company. Kroll recently published an ERP estimate of 5.0%.[53]

Q. What are the results of your final ERP estimate?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys, the estimated ERP reported by Kroll, the estimated ERP calculated by Dr. Damodaran, and the implied ERP based on my calculations.[54] The results are summarized in the following figure:

Figure 5:
Equity Risk Premium Results

IESE Business School Survey	5.5%
Kroll (Duff & Phelps) Report	5.0%
Damodaran (average)	5.0%
Garrett	5.0%
Average	**5.1%**

I used the average ERP of 5.1% from these sources in my CAPM.

Q. Please explain the final results of your CAPM analysis.

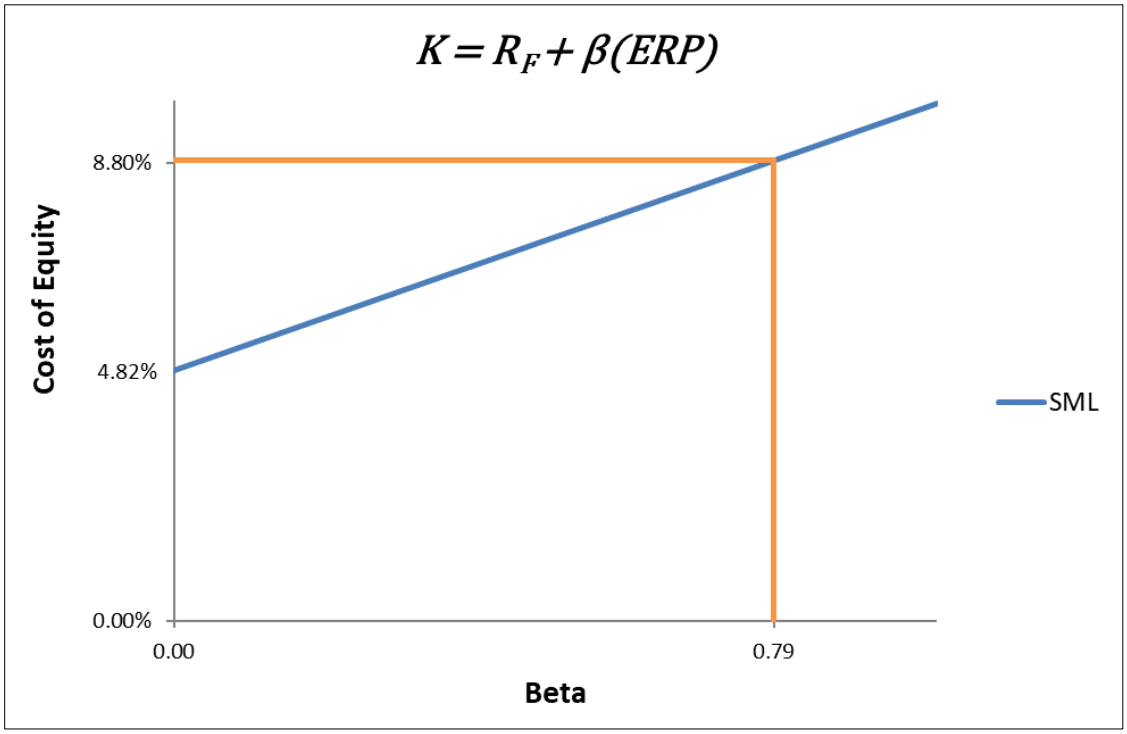
A. Using the inputs for the risk-free rate, beta, and equity risk premium discussed above, I estimate that the Company's CAPM cost of equity is 8.8%, but only if the proxy group

[53] Kroll, Cost of Capital Inputs Updated to Reflect a De-Escalation of Trae Tensions and Economic Support from Monetary and Fiscal Policies (September 3, 2025).

[54] *See also* Exhibit DJG-10.

average debt ratio is assumed (otherwise, the Company's CAPM cost of equity estimate is only 8.5%, which is discussed later in my testimony regarding the Hamada Model).[55] The CAPM can be displayed graphically through what is known as the Security Market Line ("SML"). The figure below shows the expected return (cost of equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

Figure 6:
CAPM Graph



[55] Exhibits DJG-11 and DJG-12.

The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.79 for the proxy group, and assuming the proxy group's average capital structure is used, the CAPM result is 8.8%.

D. Response to Mr. D'Ascendis's CAPM Analysis and Other Issues

Q. Please summarize the results of Mr. D'Ascendis's CAPM analysis

A. Mr. D'Ascendis's application of the CAPM produced a results ranging from 10.17% - 11.30%.[56] As part of these CAPM results, Mr. D'Ascendis incorporated a variation of the CAPM called the "empirical CAPM" ("ECAPM"). Mr. D'Ascendis also conducted another type of risk premium analysis, which produced a results from 10.41% - 10.80%.[57] Finally, Mr. D'Ascendis also considered a size premium and flotation cost premium. I will discuss each of these issues below.

Q. Do the results of Mr. D'Ascendis's CAPM and other risk premium analyses indicate a reasonable cost of equity estimate for UGI?

A. No. The primary factor which causes Mr. D'Ascendis's CAPM results to be unreasonably high is his use of an unreasonably high ERP estimate. Also, the size premium Mr. D'Ascendis applies to his CAPM results is unreasonable and unnecessary. I will discuss these issues below as well as the results of Mr. D'Ascendis's other risk premium analysis.

[56] Direct Testimony of Dylan W. D'Ascendis, p. 4, Table 2.

[57] *Id*.

1. Equity Risk Premium

Q. Did Mr. D'Ascendis rely on a reasonable measure for the ERP?

A. No. The primary factor which causes Mr. D'Ascendis's CAPM results to be unreasonably high is his use of an unreasonably high ERP estimate. Mr. D'Ascendis considered an ERP as high as 8.63% in his analysis.[58] The ERP is one of three inputs in the CAPM equation, and it is one of the most important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The average ERP calculated from my research is only 5.1%.

Q. Please discuss and illustrate how Mr. D'Ascendis's ERP compares with other estimates for the ERP.

A. The 2025 IESE Business School expert survey reports an average ERP of 5.5%. Similarly, Kroll recently estimated an ERP of 5.0%. Dr. Damodaran, one of the leading experts on the ERP, recently estimated an ERP of only 5.0%.[59] The chart in the following figure illustrates that Mr. D'Ascendis's ERP estimate higher than other reasonable, objective estimates for the ERP.[60]

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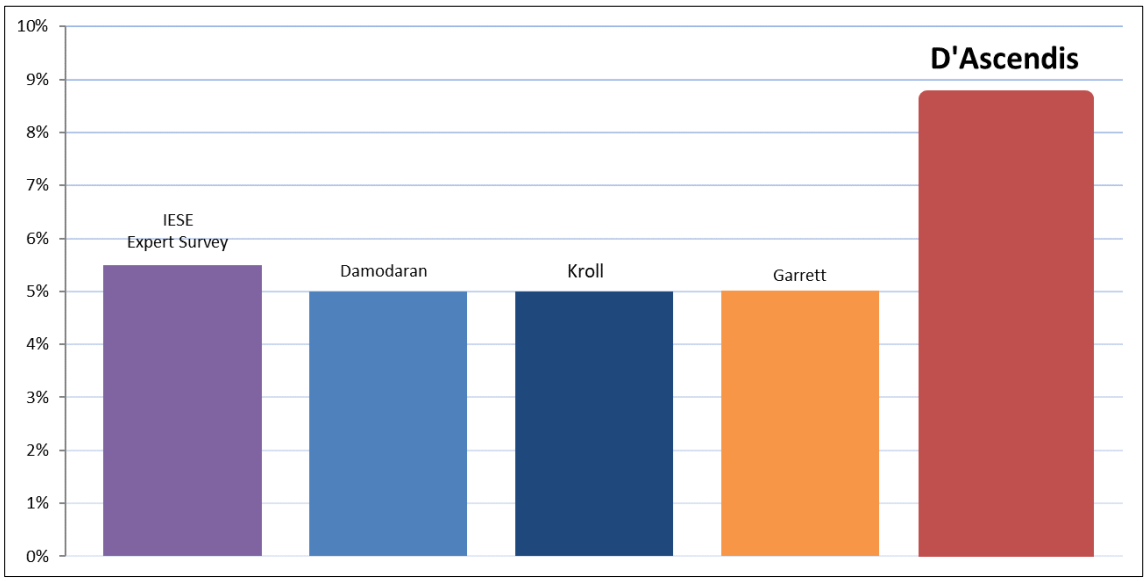
[58] *Id*. at Exhibit JEN-5.

[59] Aswath Damodaran, *Implied Equity Risk Premium Update*, DAMODARAN ONLINE, http://pages.stern.nyu.edu/~adamodar/. Dr. Damodaran estimates several ERPs using various assumptions.

[60] The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under slightly differing assumptions.

Figure 7:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP, as well as my estimate, Mr. D'Ascendis's ERP estimate is clearly too high. This factor contributes to Mr. D'Ascendis's CAPM results to overstate UGI's cost of equity.

2. <u>Other Risk Premium Analysis</u>

Q. Please describe Mr. D'Ascendis's other risk premium analysis in addition to the CAPM.

A. In addition to the CAPM, which is a risk premium model, Mr. D'Ascendis also conducted another type of risk premium model, which considers in part the difference between stock and bond returns dating back to 1926.[61] Mr. D'Ascendis also considered the authorized ROEs from past rate cases dating back to 1980.[62]

[61] *Id*. at p. 24.

[62] *Id*. at p. 30.

Q. Does the result of Mr. D'Ascendis's risk premium model indicate a reasonable cost of equity for UGI?

A. No. First, to the extent Mr. D'Ascendis based his risk premium model on prior authorized ROEs, this model does not even assess a market-based cost of equity for UGI, and thus should be rejected for that reason alone. In addition, incorporating stock and bond returns dating back to 1926 has no revenant bearing on UGI's current and forward-looking cost of equity, which is what the Company's authorized ROE should be based on. If the Commission is going to focus on a type of risk premium model to assess UGI's market-based cost of equity in this case, it should focus on the one that resulted in a Nobel Prize in Economic Sciences – the CAPM – and not the problematic risk premium model offered by Mr. D'Ascendis.

3. <u>Size Effect</u>

Q. Describe Mr. D'Ascendis's size premium.

A. Mr. D'Ascendis considers the notion that UGI's size relative to the proxy group has an increasing effect on its cost of equity. According to Mr. D'Ascendis, his size adjustment "would indicate an ROE of 12.04% for UGI Gas, which is higher than my ultimate recommendation in this case."[63] Although Mr. D'Ascendis's ultimate ROE recommendation is lower than his size-adjusted cost of equity estimate, the Commission should reject the argument that UGI's size should have an increasing effect on either its cost of equity or authorized ROE.

[63] Direct Testimony of Dylan W. D'Ascendis, p. 61, lines 17-18.

Q. Do you agree with Mr. D'Ascendis's opinion regarding UGI's size?

A. No. UGI should not receive any upward adjustment or consideration to its cost of equity estimate or authorized ROE due to its size. The "size effect" phenomenon arose from a 1981 study conducted by Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[64] According to Ibbotson, Banz's size effect study was "[o]ne of the most remarkable discoveries of modern finance."[65] Perhaps there was some merit to this idea at the time, but the size effect phenomenon was short lived. Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for approximately two years. . ." [66] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph of the Optimists*, the authors conducted an extensive empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

[64] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

[65] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

[66] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[67]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium," yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium, and what Mr. D'Ascendis is trying to do here. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[68]

In addition to the studies discussed above, other scholars have concluded similar results. According to Kalesnik and Beck:

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[67] *Id*. at 133.

[68] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015); Roger Ibbotson is Professor in the Practice Emeritus of Finance at Yale School of Management. He is also chairman of Zebra Capital Management, LLC, an equity investment, index, and hedge fund manager. He is founder, advisor and former chairman of Ibbotson Associates, now a Morningstar Company.

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[69]

For all of these reasons, the Commission should reject the arbitrary size premium proposed by the Company.

4. Flotation Costs

Q. Please summarize Mr. D'Ascendis's position regarding flotation costs.

A. Mr. D'Ascendis adds 0.12% to his cost of equity estimate as a flotation cost adjustment. The Commission should reject any argument that suggests flotation costs should have an increasing effect on UGI's cost of equity or authorized ROE.

Q. Why should flotation costs not have an increasing effect on UGI's cost of equity or authorized ROE?

A. When companies issue equity securities, they typically hire at least one investment bank as an underwriter for the securities. "Flotation costs" generally refer to the underwriter's compensation for the services it provides in connection with the securities offering. However, Mr. D'Ascendis's arguments regarding flotation costs should be rejected for several reasons, as discussed further below.

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[69] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx (emphasis added); Vitali Kalesnik is responsible for quantitative research using advanced econometric tools in asset pricing and active asset allocation. This research is used to enhance Research Affiliates' products—in particular, RAFI® Fundamental Index strategies and global tactical asset allocation products. In addition, Vitali is an adjunct professor in business and economics at Chapman University, Orange, California. Noah Beck conducts quantitative equity research relating to dynamic factor investing and smart beta strategies. He supports existing portfolios and advances research for product development.

1. Flotation costs are not actual "out-of-pocket" costs.

The Company has not experienced any out-of-pocket costs for flotation. Underwriters are not compensated in this fashion. Instead, underwriters are compensated through an "underwriting spread." An underwriting spread is the difference between the price at which the underwriter purchases the shares from the firm, and the price at which the underwriter sells the shares to investors.[70] Accordingly, the Company has not experienced any out-of-pocket flotation costs, and if it has, those costs should be included in the Company's expense schedules.

2. The market already accounts for flotation costs.

When an underwriter markets a firm's securities to investors, the investors are aware of the underwriter's fees. The investors know that a portion of the price they are paying for the shares does not go directly to the company, but instead goes to compensate the underwriter for its services. In fact, federal law requires that the underwriter's compensation be disclosed on the front page of the prospectus.[71] Thus, investors have already considered and accounted for flotation costs when making their decision to purchase shares at the quoted price.

As a result, there is no need for shareholders to receive additional compensation to account for costs they have already considered and agreed to. Similar compensation structures are found in other kinds of business transactions. For example, a homeowner

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[70] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 509 (3rd ed., South Western Cengage Learning 2010).

[71] *See* 17 C.F.R. § 229.501(b)(3) (requiring that the underwriter's discounts and commissions be disclosed on the outside cover page of the prospectus). A prospectus is a legal document that provides details about an investment offering.

may hire a realtor and sell a home for $100,000. After the realtor takes a six percent commission, the seller nets $94,000. The buyer and seller agreed to the transaction notwithstanding the realtor's commission. Obviously, it would be unreasonable for the buyer or seller to demand additional funds from anyone after the deal is completed to reimburse them for the realtor's fees. Likewise, investors of competitive firms do not expect additional compensation for flotation costs. Thus, it would not be appropriate for a commission standing in the place of competition to reward a utility's investors with this additional compensation.

3. It is inappropriate to add any additional basis points to an awarded ROE proposal that is already far above the Company's cost of equity.

For the reasons discussed above, flotation costs should be disallowed from a technical standpoint; they should also be disallowed from a policy standpoint. The Company is asking this Commission to award it a cost of equity that is nearly 300 basis points above a reasonable estimate of its market-based cost of equity. Under these circumstances, it is especially inappropriate to suggest that flotation costs should be considered in any way to increase an already inflated ROE proposal.

VIII. CAPITAL STRUCTURE

Q. Describe in general the concept of a company's "capital structure."

A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issues that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies

its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their Weighted Average Cost of Capital (WACC) by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. Please explain the concept of the "weighted average cost of capital."

A. The term "cost of capital" refers to the weighted average cost of all the components of a company's capital structure, including debt and equity. Determining the cost of debt is relatively straightforward. Interest payments on bonds are contractual, "embedded costs" that are generally calculated by dividing total interest payments by the book value of outstanding debt. Determining the cost of equity, on the other hand, is more complex. Unlike the known, contractual cost of debt, there is no explicit "cost" of equity; the cost of equity must be estimated through various financial models. Thus, the overall weighted average cost of capital includes the cost of debt and the estimated cost of equity. It is a "weighted average" because it is based upon the Company's relative levels of debt and equity, or "capital structure." Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be closely estimated. The basic WACC equation used in regulatory proceedings is presented as follows:

Equation 3:
Weighted Average Cost of Capital

$$WACC = \left(\frac{D}{D+E}\right) C_D + \left(\frac{E}{D+E}\right) C_E$$

where: $WACC$ = *weighted average cost of capital*
D = *book value of debt*
C_D = *embedded cost of debt capital*
E = *book value of equity*
C_E = *market-based cost of equity capital*

Thus, the three components of the weighted average cost of capital include the following:

(1) Cost of Equity

(2) Cost of Debt

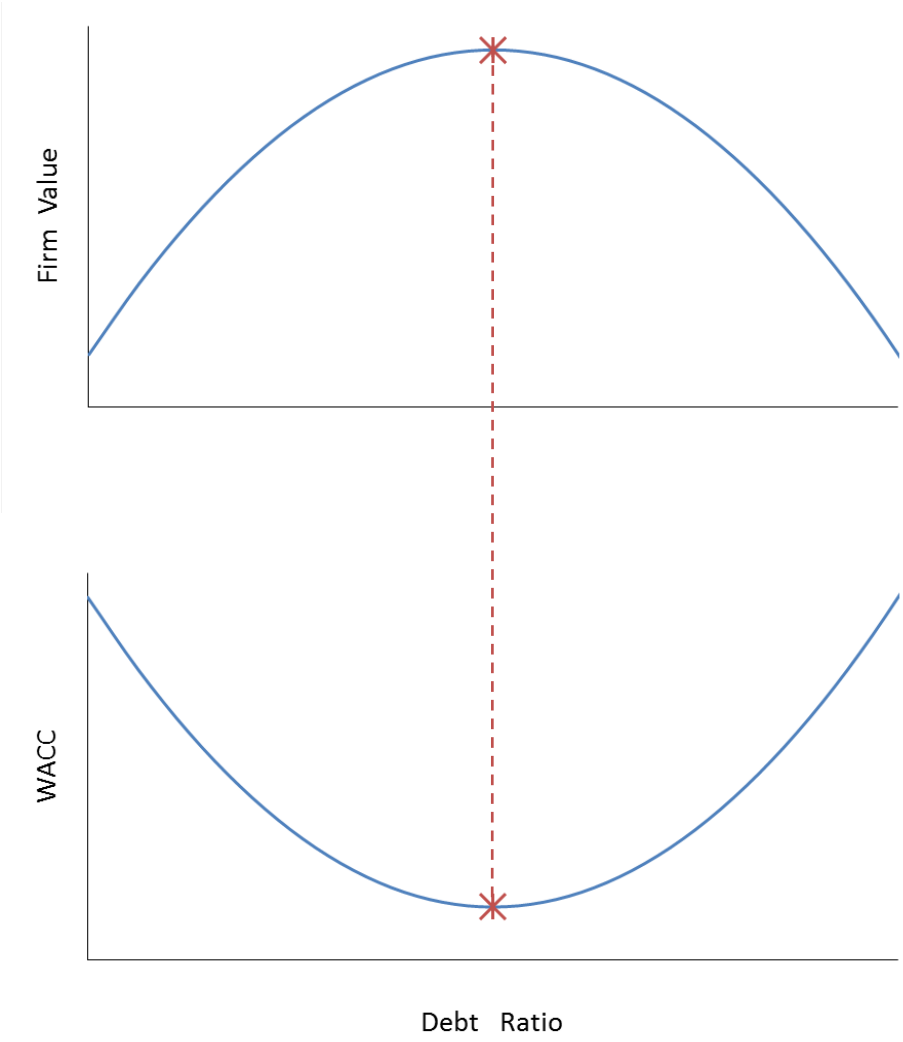
(3) Capital Structure

The term "cost of capital" is necessarily synonymous with the "weighted average cost of capital," and the terms are used interchangeably throughout this testimony.

Q. Is it true that, by increasing debt, competitive firms can add value and reduce their WACC?

A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, which causes the likelihood of loss to increase. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. Thus, if debt financing is too high, the firm's WACC will increase instead of decrease. The following Figure illustrates these concepts.

Figure 8:
Optimal Debt Ratio



As shown in this figure, a competitive firm's value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs.

Q. Does the rate base rate of return model effectively incentivize utilities to operate at the optimal capital structure?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 4:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

where:
- RR = *revenue requirement*
- O = *operating expenses*
- d = *depreciation expense*
- T = *corporate tax*
- $\boldsymbol{r}$ = ***weighted average cost of capital (WACC)***
- A = *plant investments*
- D = *accumulated depreciation*

As shown in this equation, utilities can increase their revenue requirement by *increasing* their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a Commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC. Left unrestrained, utilities will increase their equity and decrease their debt to unreasonably increase their profits that flow through to shareholders.

Q. Can utilities generally afford to have higher debt levels than other industries?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. *Utilities*, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[72]

Note that Dr. Damodaran explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure.

A. Proxy, Parent Company, and Industry Debt Ratios

Q. Please describe the debt ratios of the proxy group.

A. According to Value Line, the average capital structure mix for the proxy group consists of 51% debt and 49% equity.[73] This debt ratio is notably higher than UGI's proposed capital structure consisting of only 46% debt. More importantly, this means that UGI has a lower level of financial risk relative to the proxy group – a discrepancy that can be mathematically accounted for in terms of cost of equity estimation through the Hamada Model, which is discussed in more detail below.

[72] *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, p. 196 (emphasis added).

[73] Exhibit DJG-13.

Q. Please describe the debt ratios recently observed in competitive U.S. industries.

A. There are more than 2,000 firms in U.S. industries with higher debt ratios of at least 50%, and with an average debt ratio of about 63%.[74] The following figure shows a sample of these industries.

[74] *See* Exhibit DJG-14.

Figure 9:
Industry Debt Ratio Comparison

Industry	# Firms	Debt Ratio
Retail (Building Supply)	14	97%
Restaurant/Dining	64	95%
Hotel/Gaming	63	82%
Brokerage & Investment Banking	32	79%
Retail (Automotive)	34	77%
Hospitals/Healthcare Facilities	31	76%
Rubber& Tires	3	74%
Bank (Money Center)	15	73%
Recreation	49	72%
Air Transport	23	71%
Food Wholesalers	13	69%
Retail (Grocery and Food)	15	67%
Chemical (Diversified)	4	66%
Cable TV	9	65%
Telecom (Wireless)	12	65%
Advertising	52	64%
Transportation	19	64%
R.E.I.T.	190	63%
Power	46	63%
Oil/Gas Distribution	23	63%
Transportation (Railroads)	4	62%
Computers/Peripherals	36	61%
Telecom. Services	39	61%
Broadcasting	24	61%
Auto & Truck	33	60%
Retail (Special Lines)	94	60%
Software (Internet)	29	60%
Green & Renewable Energy	15	59%
Environmental & Waste Services	53	58%
Office Equipment & Services	14	58%
Utility (General)	14	58%
Beverage (Soft)	27	57%
Apparel	35	56%
Information Services	15	56%
Total / Average	**1,143**	**67%**

Many of the industries shown here, like public utilities, are generally well-established industries with large amounts of capital assets. The shareholders of these industries generally prefer these higher debt ratios in order to maximize their profits. There are several notable industries that are relatively comparable to public utilities. For example, the Cable TV, Telecom, Power, and Telecom industries all have an average debt ratios of at least 60%.

Q. Are you basing your capital structure recommendation on any industry or company outside of the proxy group?

A. No. I am basing my capital structure recommendation primarily on the proxy group average capital structure. I present the capital structures observed in other competitive industries to show it is not uncommon for firms to operate with relatively higher amounts of leverage.

Q. Please describe the capital structure of the Company's parent company, UGI Corp.

A. At the end of 2025, UGI's parent company reported a long-term debt ratio of 57.8%, which is considerable higher than the Company's proposed ratemaking debt ratio of only 46%. This fact alone shows that UGI's debt ratio should be higher than 46% for ratemaking purposes. Given the parent company's debt ratio, a ratemaking debt ratio of only 51% for UGI would be very reasonable and conservative.

Q. Please discuss in more detail the problems that arise when there is such a large discrepancy between the parent company and subsidiary utility's debt ratios.

A. Since UGI is a wholly owned subsidiary of UGI Corp., the Company's "equity" on its balance sheet is funded by UGI Corp. Since the parent company has a debt ratio of 58%, this means UGI Corp. is using debt to finance the Company's "equity." Since the Company also issues its own debt, this strategy is known as "double leverage." While this arrangement is not problematic among competitive firms, it often results in unfair,

excessive returns for regulated utilities to the extent there is not an adjustment made by the regulator. If no adjustment is made, shareholders of the parent company effectively earn a high-cost equity return on its low-cost debt. In order to mitigate the excessive return that would otherwise occur through double leverage, the Commission should impute a capital structure that is equal to the proxy group average. In light of the fact the average proxy debt ratio of 51% is still considerably less than UGI Corp's debt ratio of 58%, my proposed capital structure adjustment is very reasonable.

Q. Is there other factors indicating UGI Corp. may be benefiting from double leverage?

A. Yes. According to Value Line, UGI Corp's earned ROE last year was 15.2%, which is significantly higher than its cost of equity, or even the inflated ROEs typically authorized by regulators.

B. The Hamada Model: Capital Structure's Effect on ROE

Q. Have you considered the impact that your capital structure recommendation could have on the company's indicated cost of equity?

A. Yes. I assessed the impact of my capital structure proposal on the Company's cost of equity estimate by using the Hamada model.

Q. What is the premise of the Hamada model?

A. The Hamada formula can be used to analyze changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be

removed, which is accomplished through the Hamada formula. The Hamada formula for unlevering beta is stated as follows:[75]

Equation 5:
Hamada Formula

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c)\left(\frac{D}{E}\right)\right]}$$

where: β_U = *unlevered beta (or "asset" beta)*
β_L = *average levered beta of proxy group*
T_C = *corporate tax rate*
D = *book value of debt*
E = *book value of equity*

Using this equation, the beta for the firm can be unlevered, and then "relevered" based on various debt ratios (by rearranging this equation to solve for β_L).

Q. Please summarize the results of the Hamada formula based on the average capital structure of the proxy group.

A. The average capital structure of the proxy group consists of 58% debt and 42% equity. Because UGI's debt ratio is notably lower than that of the proxy group, when UGI is "relevered" to match the proxy group, it results in a lower ROE than if UGI had been operating with a capital structure equal to that of the proxy group. This makes sense because UGI has less financial risk relative to the proxy group due to the lower amount of debt in its capital structure. The results of my Hamada model are presented in the following figure.

[75] Damodaran *supra* n. 22 at 197. This formula was originally developed by Hamada in 1972.

Figure 10:
Hamada Model ROE

Unlevering Beta	
Proxy Debt Ratio	51%
Proxy Equity Ratio	49%
Proxy Debt / Equity Ratio	1.0
Tax Rate	21%
Equity Risk Premium	5.1%
Risk-free Rate	4.8%
Proxy Group Beta	0.79
Unlevered Beta	0.43

Relevered Betas and Cost of Equity Estimates

Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity
0%	0.0	0.43	7.0%
20%	0.3	0.52	7.5%
25%	0.3	0.54	7.6%
30%	0.4	0.58	7.8%
46%	0.8	0.72	8.5%
51%	1.0	0.79	8.8%
60%	1.5	0.94	9.6%

According to the results of the Hamada model, if the Commission were to adopt the Company's proposed capital structure consisting of only 46% debt, then its indicated cost of equity estimate (under the CAPM) would be only 8.5%.[76] Alternatively, if the Commission adopts my proposed capital structure consisting of 51% debt – equal to the proxy group average, then UGI's indicated cost of equity un the CAPM is 8.8%. An

[76] *See* Exhibit DJG-15.

authorized ROE of 8.8% and a ratemaking debt ratio of 51% are my primary recommendations to the Commission.

IX. CONCLUSION

Q. Please summarize your analyses and conclusions regarding UGI's cost of equity.

A. A utility's awarded ROE should be based on its cost of equity, which can be estimated using various financial models. In estimating UGI's cost of equity, I performed a cost of equity analysis on a proxy group of utility companies using the two most widely used and widely-accepted financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. I conducted two variations of both the CAPM and DCF Model. The results are shown in the figure below.

Figure 11:
Cost of Equity Model Summary

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	8.8%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.5%
DCF Model (Analyst Growth)	8.2%
DCF Model (Sustainable Growth)	7.6%
Model Average	**8.3%**
Recommended ROE	**8.8%**

Q. Please summarize your recommendation to the Commission regarding UGI's authorized rate of return.

A. My primary recommendation to the Commission is an authorized ROE of 8.8% for UGI and an imputed capital structure consisting of 51% debt and 49% equity. If the Commission adopts the Company's proposed capital structure, my alternative recommendation to the Commission is an authorized ROE of 8.5%. My recommendations are summarized in the following figures.

Figure 12:
Primary Recommendation

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	51.0%	5.17%	2.64%
Common Equity	49.0%	8.80%	4.31%
Total	100.0%		6.95%

Figure 13:
Alternative Recommendation

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	45.8%	5.17%	2.37%
Common Equity	54.3%	8.50%	4.61%
Total	100.0%		6.98%

Q. Does this conclude your testimony?

A. Yes.

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EDUCATION

University of Oklahoma — Norman, OK
Master of Business Administration — 2014
Areas of Concentration: Finance, Energy

University of Oklahoma College of Law — Norman, OK
Juris Doctor — 2007
Member, American Indian Law Review

University of Oklahoma — Norman, OK
Bachelor of Business Administration — 2003
Major: Finance

PROFESSIONAL DESIGNATIONS

Society of Depreciation Professionals
Certified Depreciation Professional (CDP)

Society of Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst (CRRA)

WORK EXPERIENCE

Resolve Utility Consulting PLLC — Oklahoma City, OK
Managing Member — 2016 – Present
Provide expert analysis and testimony specializing in depreciation and cost of capital issues for clients in utility regulatory proceedings.

Oklahoma Corporation Commission — Oklahoma City, OK
Public Utility Regulatory Analyst — 2012 – 2016
Assistant General Counsel — 2011 – 2012
Represented commission staff in utility regulatory proceedings and provided legal opinions to commissioners. Provided expert analysis and testimony in depreciation, cost of capital, incentive compensation, payroll and other issues.

Perebus Counsel, PLLC — Oklahoma City, OK
Managing Member — 2009 – 2011
Represented clients in the areas of family law, estate planning, debt negotiations, business organization, and utility regulation.

Moricoli & Schovanec, P.C. — Oklahoma City, OK
Associate Attorney — 2007 – 2009
Represented clients in the areas of contracts, oil and gas, business structures and estate administration.

TEACHING EXPERIENCE

University of Oklahoma — Norman, OK
Adjunct Instructor – "Conflict Resolution" — 2014 – 2021
Adjunct Instructor – "Ethics in Leadership"

Rose State College — Midwest City, OK
Adjunct Instructor – "Legal Research" — 2013 – 2015
Adjunct Instructor – "Oil & Gas Law"

PROFESSIONAL ASSOCIATIONS

Oklahoma Bar Association — 2007 – Present

Society of Depreciation Professionals — 2014 – Present
Board Member – President — 2017
Participate in management of operations, attend meetings, review performance, organize presentation agenda.

Society of Utility Regulatory Financial Analysts — 2014 – Present

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Delaware Public Service Commission	Artesian Water Company	25-0346	Cost of capital, awarded rate of return, capital structure	Division of the Public Advocate
Pennsylvania Public Utility Commission	Pennsylvania-American Water Company	A-2024-3049015	Fair market value review (Borough of Greenville)	Pennsylvania Office of Consumer Advocate
Public Service Commission of South Carolina	Kiawah Island Utility, Inc.	2025-243-WS	Cost of capital, depreciation rates, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	City of Lancaster - Bureau of Water	R-2025-3057237	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Massachusetts Department of Public Utilities	Liberty Utilities Corp. d/b/a Liberty	D.P.U. 25-85	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	2025.09.072	Cost of capital, awarded rate of return, capital structure	Montana Consumer Counsel and Denbury Onshore LLC
Wyoming Public Service Commission	Montana-Dakota Utilities Co.	20004-174-ER-25	Depreciation rates, service lives, net salvage	Wyoming Office of Consumer Advocate
Washington Utilities & Transportation Commission	Northwest Natural Gas Company	UG-250610	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
Pennsylvania Public Utility Commission	Pennsylvania American Water Company	R-2025-3057983 R-2025-3058051	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
New York State Public Service Commission	New York State Electric & Gas and Rochester Gas and Electric Corporation	25-E-0375, 25-G-0378 25-E-0379, 25-G-0380	Cost of capital, depreciation rates, net salvage	Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection
Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	R-2025-3057164	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	OS-24-00028202	Depreciation rates, service lives, net salvage	The City of El Paso
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 58964	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
New Jersey Board of Public Utilities	South Jersey Gas	GR25110627	Cost of capital, awarded rate of return, capital structure	Staff of the New Jersey Board of Public Utilities

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Maryland Public Service Commission	Potomac Electric Power Company	9820	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
New Jersey Board of Public Utilities	Rockland Electric Company	ER25060374	Cost of capital, depreciation rates, net salvage	Staff of the New Jersey Board of Public Utilities
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-25-0105	Cost of capital, depreciation rates, net salvage	Arizona Large Customer Group and Freeport Minerals Corporation
New Jersey Board of Public Utilities	Middlesex Water Company	WR25060372	Cost of capital, depreciation rates, net salvage	Staff of the New Jersey Board of Public Utilities
Maryland Public Service Commission	Maryland-American Water Company	9808	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Arizona Corporation Commission	Tucson Electric Power Company	E-01933A-25-0103	Cost of capital, awarded rate of return, capital structure	Arizona Large Customer Group and Freeport Minerals Corporation
Public Service Commission of West Virginia	West Virginia American Water Company	25-0426-W-42T 25-0428-S-42T	Cost of capital, awarded rate of return, capital structure	Consumer Advocate Division of the Public Service Commission of West Virginia
Federal Energy Regulatory Commission	Pacific Gas and Electric Company	ER24-96	Depreciation rates, service lives, net salvage	Northern California Power Agency
Public Utility Commission of Texas	Oncor Electric Delivery Company LLC	PUC 58306	Depreciation rates, service lives, net salvage	Alliance of Oncor Cities
Public Service Commission of West Virginia	Hope Gas, Inc.	24-0678-G-D	Cost of capital, awarded rate of return, capital structure	Consumer Advocate Division of the Public Service Commission of West Virginia
Pennsylvania Public Utility Commission	The York Water Company, et al	R-2025-3053442 R-2025-3053573	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utility Commission	UGI Utilities, Inc.	R-2024-3052716	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Wyoming Public Service Commission	Rocky Mountain Power	20000-671-ER-24	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 2023-000086	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Public Service Commission of South Carolina	Piedmont Natural Gas Company	2022-89-G 2024-179-G	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Florida Public Service Commission	Peoples Gas System	20250029-GU	Cost of capital, awarded rate of return, capital structure	Florida Office of Public Counsel
Public Service Commission of the State of Montana	NorthWestern Energy	2024.05.053	Cost of capital, depreciation rates, net salvage	Montana Consumer Counsel and Montana Large Customer Group
New York State Public Service Commission	Niagara Mohawk Power Corporation	24-E-0322 24-G-0323	Depreciation rates, service lives, net salvage, depreciation reserve	Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection
Public Utilities Commission of Ohio	Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company	24-468-EL-AIR, *et seq* .	Depreciation rates, service lives, net salvage	Office of the Ohio Consumers' Counsel
Public Utility Commission of Texas	El Paso Electric Company	PUC 57568	Depreciation rates, service lives, net salvage	The City of El Paso
Public Service Commission of Utah	Enbridge Gas Utah	25-057-06	Cost of capital, depreciation rates, net salvage	Office of Consumer Services
Pennsylvania Public Utility Commission	Pennsylvania-American Water Company	A-2025-3052983	Fair market value review (Elizabeth Borough)	Pennsylvania Office of Consumer Advocate
Commonwealth of Virginia State Corporation Commission	Virginia Electric and Power Company	PUR-2025-00058	Cost of capital, awarded rate of return, capital structure	Data Center Coalition
Delaware Public Service Commission	Delmarva Power & Light Company	24-1044	Cost of capital, depreciation rates, net salvage	Division of the Public Advocate
New York State Public Service Commission	Consolidated Edison Company of New York, Inc.	25-E-0072 25-G-0073	Depreciation rates, service lives, net salvage, depreciation reserve	Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection
Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	R-2025-3053499	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 58028	System restoration costs	Texas Coast Utilities Coalition
Mississippi Public Service Commission	Atmos Energy Corporation	2025-UN-59	Depreciation rates, service lives, net salvage	Mississippi Public Utilities Staff
Public Service Commission of West Virginia	Appalachian Power Company and Wheeling Power Company	24-0854-E-42T	Cost of capital, awarded rate of return, capital structure	Consumer Advocate Division of the Public Service Commission of West Virginia
Public Service Commission of West Virginia	Appalachian Power Company and Wheeling Power Company	24-0670-E-D	Depreciation rates, service lives, net salvage	Consumer Advocate Division of the Public Service Commission of West Virginia

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
New Jersey Board of Public Utilities	Atlantic City Electric Company	ER24110854	Cost of capital, awarded rate of return, capital structure	Staff of the New Jersey Board of Public Utilities
Pennsylvania Public Utility Commission	Aqua Pennsylvania, Inc.	A-2022-3033138	Fair market value review (Beaver Falls)	Pennsylvania Office of Consumer Advocate
Mississippi Public Service Commission	Mississippi Power Company	2024-UN-117	Depreciation rates, service lives, net salvage	Mississippi Public Utilities Staff
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	2024.05.061	Cost of capital, depreciation rates, net salvage	Montana Consumer Counsel
Maryland Public Service Commission	Columbia Gas of Maryland	9754	Cost of capital, depreciation rates, net salvage	Maryland Office of People's Counsel
Railroad Commission of Texas	Atmos Energy, Mid-Tex Division	OS-24-00019196	Depreciation rates, service lives, net salvage	Atmos Texas Municipalities
Wyoming Public Service Commission	Montana-Dakota Utilities Co.	30013-415-GR-24	Depreciation rates, service lives, net salvage	Wyoming Office of Consumer Advocate
Indiana Utility Regulatory Commission	Duke Energy Indiana	46038	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Railroad Commission of Texas	Atmos Energy, West Texas Division	OS-24-00018879	Depreciation rates, service lives, net salvage	The Cities of Amarillo, Lubbock, Dalhart, and Channing
Washington Utilities & Transportation Commission	Cascadia Water, LLC	UW-240151	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Railroad Commission of Texas	West Texas Gas Utility	OS-24-00017816	Cost of capital, depreciation rates, net salvage	Alliance of WTG Municipalities
Maryland Public Service Commission	Washington Gas Light Company	9737	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Railroad Commission of Texas	Texas Gas Services Company	OS-24-00017471	Depreciation rates, service lives, net salvage	The Steering Committee of Cities
Pennsylvania Public Utility Commission	Veolia Water Pennsylvania, Inc.	R-2024-3045192 R-2024-3045193	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utility Commission	PECO Energy Company - Gas Division	R-2024-3046932	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	PECO Energy Company - Electric Division	R-2024-3046931	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 2023-000087	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Maryland Public Service Commission	Maryland Water Service, Inc.	9729	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Kansas Corporation Commission	Kansas Gas Service	24-KGSG-610-RTS	Depreciation rates, service lives, net salvage	The Citizens' Utility Ratepayer Board
Pennsylvania Public Utility Commission	FirstEnergy Pennsylvania Electric Company	R-2024-3047068	Depreciation rates, service lives, net salvage	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Chesapeake Utilities Corporation Sandpiper Energy, Inc. Elkton Gas Company	9721	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Pennsylvania Public Utility Commission	Duquesne Light Company	R-2024-3046523	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 56211	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Washington Utilities & Transportation Commission	Avista Corporation	UE-240006 UG-240007	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Public Utility Commission of Texas	AEP Texas Inc.	PUC 56165	Depreciation rates, service lives, net salvage	Cities Served by AEP Texas
Public Utilities Commission of Nevada	Southwest Gas Corporation	23-09012	Depreciation rates, service lives, net salvage	Bureau of Consumer Protection
Public Utilities Commission of the State of California	Southern California Edison	A.23-05-010	Depreciation rates, service lives, net salvage	The Utility Reform Network
Pennsylvania Public Utility Commission	Pennsylvania-American Water Company	R-2023-3043189 R-2023-3043190	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45967	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company D/B/A National Grid	D.P.U. 23-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Iowa Utilities Board	Interstate Power and Light Company	RPU-2023-0002	Depreciation rates, service lives, net salvage	Office of Consumer Advocate
Public Service Commission of South Carolina	Duke Energy Carolinas	2023-388-E 2023-403-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Indiana Utility Regulatory Commission	Citizens Energy Group	45988	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Railroad Commission of Texas	CenterPoint Energy Resources Corp.	OS-23-00015513	Depreciation rates, service lives, net salvage	Alliance of CenterPoint Municipalities
Indiana Utility Regulatory Commission	CenterPoint Energy Indiana South	45990	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Delaware Public Service Commission	Artesian Water Company, Inc.	23-0601	Cost of capital, depreciation rates, net salvage	Division of the Public Advocate
Maryland Public Service Commission	Washington Gas Light Company	9704	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Delaware Public Service Commission	Veolia Water Delaware Inc.	23-0598	Cost of capital, awarded rate of return, capital structure	Division of the Public Advocate
Connecticut Public Utilities Regulatory Authority	United Illuminating Company	22-08-08	Depreciation rates, service lives, net salvage	PURA Staff
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 54634	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Railroad Commission of Texas	SiEnergy, LP	OS-23-00013504	Depreciation rates, service lives, net salvage	Texas municipal intervenor group
Pennsylvania Public Utility Commission	Aqua Pennsylvania, Inc.	A-2022-3034143	Fair market value review	Pennsylvania Office of Consumer Advocate
Wyoming Public Service Commission	Rocky Mountain Power	20000-633-ER-23	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Maryland Public Service Commission	Potomac Electric Power Company	9702	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Public Utilities Commission of Nevada	Nevada Power Company d/b/a NV Energy	23-06007 23-06008	Depreciation rates, service lives, net salvage	Bureau of Consumer Protection

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Utilities Commission of Ohio	Northeast Ohio Natural Gas Corp.	23-0154-GA-AIR	Cost of capital, awarded rate of return, capital structure	Office of the Ohio Consumers' Counsel
New York State Public Service Commission	The Brooklyn Union Gas Company and Keyspan Gas East Corporation d/b/a Nation Grid	23-G-0225 23-G-0226	Depreciation rates, service lives, net salvage, depreciation reserve	The City of New York
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-23-11	Cost of capital, awarded rate of return, capital structure	Micron Technology, Inc.
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45933	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Massachusetts Department of Public Utilities	Fitchburg Gas and Electric Company d/b/a Unitil	D.P.U. 23-80; D.P.U. 23-81	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Kansas Corporation Commission	Evergy Kansas Central, Evergy Kansas South, and Evergy Metro	23-EKCE-775-RTS	Depreciation rates, service lives, net salvage	The Citizens' Utility Ratepayer Board
Delaware Public Service Commission	Delmarva Power & Light Company	22-0897	Cost of capital, awarded rate of return, capital structure	Division of the Public Advocate
Connecticut Public Utilities Regulatory Authority	Connecticut Water Company	23-08-32	Depreciation rates, service lives, net salvage	PURA Staff
Connecticut Public Utilities Regulatory Authority	Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company	23-11-02	Depreciation rates, service lives, net salvage	PURA Staff
Railroad Commission of Texas	Atmos Pipeline – Texas	OS-23-00013758	Depreciation rates, service lives, net salvage	Atmos Texas Municipalities
Wyoming Public Service Commission	Black Hills Wyoming Gas	30026-78-GR-23	Depreciation rates, service lives, net salvage	Wyoming Office of Consumer Advocate
Indiana Utility Regulatory Commission	Indianapolis Power & Light Company d/b/a AES Indiana	45911	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
New Mexico Public Regulation Commission	Southwestern Public Service Company	22-00286-UT	Cost of capital, depreciation rates, net salvage	The New Mexico Large Customer Group; Occidental Permian
Public Utilities Commission of the State of California	Southern California Gas Company San Diego Gas & Electric Company	A.22-05-015 A.22-05-016	Depreciation rates, service lives, net salvage	The Utility Reform Network
Public Utilties Commission of the State of Colorado	Public Service Company of Colorado	22AL-0530E 22AL-0478E	Cost of capital, awarded rate of return, capital structure	Colorado Energy Consumers

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
New Mexico Public Regulatory Commission	Public Service Company of New Mexico	22-00270-UT	Cost of capital, depreciation rates, net salvage	The Albuquerque Bernalillo County Water Utility Authority
Florida Public Service Commission	Peoples Gas System	20230023-GU 20220219-GU 20220212-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Maryland Public Service Commission	Potomac Edison Company	9695	Cost of capital, depreciation rates, net salvage	Maryland Office of People's Counsel
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	2022.11.099	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Indiana-American Water Company	45870	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Service Commission of South Carolina	Dominion Energy South Carolina	2023-70-G	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Maryland Public Service Commission	Columbia Gas of Maryland	9701	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Pennsylvania Public Utility Commission	Columbia Water Company	R-2023-3040258	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Baltimore Gas and Electric Company	9692	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-22-0144	Cost of capital, awarded rate of return, capital structure	Residential Utility Consumer Office
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 2022-000093	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Public Service Commission of the State of Montana	NorthWestern Energy	2022.07.078	Cost of capital, depreciation rates, net salvage	Montana Consumer Counsel and Montana Large Customer Group
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45772	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Service Commission of South Carolina	Duke Energy Progress	2022-254-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Wyoming Public Service Commission	Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy	20003-214-ER-22	Depreciation rates, service lives, net salvage	Wyoming Office of Consumer Advocate

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Railroad Commission of Texas	Texas Gas Services Company	OS-22-00009896	Depreciation rates, service lives, net salvage	The City of El Paso
Public Utilities Commission of Nevada	Sierra Pacific Power Company	22-06014	Depreciation rates, service lives, net salvage	Bureau of Consumer Protection
Washington Utilities & Transportation Commission	Puget Sound Energy	UE-220066 UG-220067 UG-210918	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
Public Utility Commission of Texas	Oncor Electric Delivery Company LLC	PUC 53601	Depreciation rates, service lives, net salvage	Alliance of Oncor Cities
Florida Public Service Commission	Florida Public Utilities Company	20220067-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 53719	Depreciation rates, decommissioning costs	Texas Municipal Group
Florida Public Service Commission	Florida City Gas	2020069-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Connecticut Public Utilities Regulatory Authority	Aquarion Water Company of Connecticut	22-07-01	Depreciation rates, service lives, net salvage	PURA Staff
Washington Utilities & Transportation Commission	Avista Corporation	UE-220053 UG-220054 UE-210854	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Federal Energy Regulatory Commission	ANR Pipeline Company	RP22-501-000	Depreciation rates, service lives, net salvage	Ascent Resources - Utica, LLC
Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	R-2022-3031211	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Service Commission of South Carolina	Piedmont Natural Gas Company	2022-89-G	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	UGI Utilities, Inc. - Gas Division	R-2021-3030218	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	A.21-06-021	Depreciation rates, service lives, net salvage	The Utility Reform Network
Pennsylvania Public Utility Commission	PECO Energy Company - Gas Division	R-2022-3031113	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 202100164	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Massachusetts Department of Public Utilities	NSTAR Electric Company D/B/A Eversource Energy	D.P.U. 22-22	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Michigan Public Service Company	DTE Electric Company	U-20836	Cost of capital, awarded rate of return, capital structure	Michigan Environmental Council and Citizens Utility Board of Michigan
New York State Public Service Commission	Consolidated Edison Company of New York, Inc.	22-E-0064 22-G-0065	Depreciation rates, service lives, net salvage, depreciation reserve	The City of New York
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / East Whiteland Township	A-2021-3026132	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
Public Service Commission of South Carolina	Kiawah Island Utility, Inc.	2021-324-WS	Cost of capital, awarded rate of return, capital structure	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / Willistown Township	A-2021-3027268	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45621	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Arkansas Public Service Commission	Southwestern Electric Power Company	21-070-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Federal Energy Regulatory Commission	Southern Star Central Gas Pipeline	RP21-778-002	Depreciation rates, service lives, net salvage	Consumer-Owned Shippers
Railroad Commission of Texas	Participating Texas gas utilities in consolidated proceeding	OS-21-00007061	Securitization of extraordinary gas costs arising from winter storms	The City of El Paso
Public Service Commission of South Carolina	Palmetto Wastewater Reclamation, Inc.	2021-153-S	Cost of capital, awarded rate of return, capital structure, ring-fencing	South Carolina Office of Regulatory Staff
Public Utilties Commission of the State of Colorado	Public Service Company of Colorado	21AL-0317E	Cost of capital, depreciation rates, net salvage	Colorado Energy Consumers
Pennsylvania Public Utility Commission	City of Lancaster - Water Department	R-2021-3026682	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 51802	Depreciation rates, service lives, net salvage	The Alliance of Xcel Municipalities

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	The Borough of Hanover - Hanover Municipal Waterworks	R-2021-3026116	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Delmarva Power & Light Company	9670	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 202100063	Cost of capital, awarded rate of return, capital structure	Oklahoma Industrial Energy Consumers
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45576	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	El Paso Electric Company	PUC 52195	Depreciation rates, service lives, net salvage	The City of El Paso
Pennsylvania Public Utility Commission	Aqua Pennsylvania	R-2021-3027385	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Service Commission of the State of Montana	NorthWestern Energy	D2021.02.022	Cost of capital, awarded rate of return, capital structure	Montana Consumer Counsel
Pennsylvania Public Utility Commission	PECO Energy Company	R-2021-3024601	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	20-00238-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 202100055	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Pennsylvania Public Utility Commission	Duquesne Light Company	R-2021-3024750	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Columbia Gas of Maryland	9664	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Southern Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45447	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 51415	Depreciation rates, service lives, net salvage	Cities Advocating Reasonable Deregulation
New Mexico Public Regulatory Commission	Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., PNM, and PNM Resources	20-00222-UT	Ring fencing and capital structure	The Albuquerque Bernalillo County Water Utility Authority

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Indiana Utility Regulatory Commission	Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45468	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of Nevada	Nevada Power Company and Sierra Pacific Power Company, d/b/a NV Energy	20-07023	Construction work in progress	MGM Resorts International, Caesars Enterprise Services, LLC, and the Southern Nevada Water Authority
Massachusetts Department of Public Utilities	Boston Gas Company, d/b/a National Grid	D.P.U. 20-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Public Service Commission of the State of Montana	ABACO Energy Services, LLC	D2020.07.082	Cost of capital and authorized rate of return	Montana Consumer Counsel
Maryland Public Service Commission	Washington Gas Light Company	9651	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Florida Public Service Commission	Utilities, Inc. of Florida	20200139-WS	Cost of capital and authorized rate of return	Florida Office of Public Counsel
New Mexico Public Regulatory Commission	El Paso Electric Company	20-00104-UT	Cost of capital, depreciation rates, net salvage	City of Las Cruces and Doña Ana County
Public Utilities Commission of Nevada	Nevada Power Company	20-06003	Cost of capital, awarded rate of return, capital structure, earnings sharing	MGM Resorts International, Caesars Enterprise Services, LLC, Wynn Las Vegas, LLC, Smart Energy Alliance, and Circus Circus Las Vegas, LLC
Wyoming Public Service Commission	Rocky Mountain Power	20000-578-ER-20	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Florida Public Service Commission	Peoples Gas System	20200051-GU 20200166-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Wyoming Public Service Commission	Rocky Mountain Power	20000-539-EA-18	Depreciation rates, service lives, net salvage	Wyoming Industrial Energy Consumers
Public Service Commission of South Carolina	Dominion Energy South Carolina	2020-125-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	The City of Bethlehem	2020-3020256	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	GUD 10928	Depreciation rates, service lives, net salvage	Gulf Coast Service Area Steering Committee
Public Utilities Commission of the State of California	Southern California Edison	A.19-08-013	Depreciation rates, service lives, net salvage	The Utility Reform Network

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Massachusetts Department of Public Utilities	NSTAR Gas Company	D.P.U. 19-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Georgia Public Service Commission	Liberty Utilities (Peach State Natural Gas)	42959	Depreciation rates, service lives, net salvage	Public Interest Advocacy Staff
Florida Public Service Commission	Florida Public Utilities Company	20190155-El 20190156-El 20190174-El	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Illinois Commerce Commission	Commonwealth Edison Company	20-0393	Depreciation rates, service lives, net salvage	The Office of the Illinois Attorney General
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 49831	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Public Service Commission of South Carolina	Blue Granite Water Company	2019-290-WS	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Railroad Commission of Texas	CenterPoint Energy Resources	GUD 10920	Depreciation rates and grouping procedure	Alliance of CenterPoint Municipalities
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / East Norriton Township	A-2019-3009052	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	19-00170-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Indiana Utility Regulatory Commission	Duke Energy Indiana	45253	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Maryland Public Service Commission	Columbia Gas of Maryland	9609	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-190334	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45235	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	18-12-009	Depreciation rates, service lives, net salvage	The Utility Reform Network
Oklahoma Corporation Commission	The Empire District Electric Company	PUD 201800133	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Arkansas Public Service Commission	Southwestern Electric Power Company	19-008-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 49421	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company	D.P.U. 18-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201800140	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2018.9.60	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45159	Depreciation rates, grouping procedure, demolition costs	Indiana Office of Utility Consumer Counselor
Public Service Commission of the State of Montana	NorthWestern Energy	D2018.2.12	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 201800097	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Wal-Mart
Nevada Public Utilities Commission	Southwest Gas Corporation	18-05031	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 48401	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201700496	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Maryland Public Service Commission	Washington Gas Light Company	9481	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Citizens Energy Group	45039	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 48371	Depreciation rates, decommissioning costs	Texas Municipal Group
Washington Utilities & Transportation Commission	Avista Corporation	UE-180167	Depreciation rates, service lives, net salvage	Washington Office of Attorney General

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
New Mexico Public Regulation Commission	Southwestern Public Service Company	17-00255-UT	Cost of capital and authorized rate of return	HollyFrontier Navajo Refining; Occidental Permian
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 47527	Depreciation rates, plant service lives	Alliance of Xcel Municipalities
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2017.9.79	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Florida Public Service Commission	Florida City Gas	20170179-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-170485	Cost of capital and authorized rate of return	Washington Office of Attorney General
Wyoming Public Service Commission	Powder River Energy Corporation	10014-182-CA-17	Credit analysis, cost of capital	Private customer
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201700151	Depreciation, terminal salvage, risk analysis	Oklahoma Industrial Energy Consumers
Public Utility Commission of Texas	Oncor Electric Delivery Company	PUC 46957	Depreciation rates, simulated analysis	Alliance of Oncor Cities
Nevada Public Utilities Commission	Nevada Power Company	17-06004	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	El Paso Electric Company	PUC 46831	Depreciation rates, interim retirements	City of El Paso
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-24	Accelerated depreciation of North Valmy plant	Micron Technology, Inc.
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-23	Depreciation rates, service lives, net salvage	Micron Technology, Inc.
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 46449	Depreciation rates, decommissioning costs	Cities Advocating Reasonable Deregulation
Massachusetts Department of Public Utilities	Eversource Energy	D.P.U. 17-05	Cost of capital, capital structure, and rate of return	Sunrun Inc.; Energy Freedom Coalition of America
Railroad Commission of Texas	Atmos Pipeline - Texas	GUD 10580	Depreciation rates, grouping procedure	City of Dallas

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Utility Commission of Texas	Sharyland Utility Company	PUC 45414	Depreciation rates, simulated analysis	City of Mission
Oklahoma Corporation Commission	Empire District Electric Company	PUD 201600468	Cost of capital, depreciation rates	Oklahoma Industrial Energy Consumers
Railroad Commission of Texas	CenterPoint Energy Texas Gas	GUD 10567	Depreciation rates, simulated plant analysis	Texas Coast Utilities Coalition
Arkansas Public Service Commission	Oklahoma Gas & Electric Company	160-159-GU	Cost of capital, depreciation rates, terminal salvage	Arkansas River Valley Energy Consumers; Wal-Mart
Florida Public Service Commission	Peoples Gas	160-159-GU	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-16-0036	Cost of capital, depreciation rates, terminal salvage	Energy Freedom Coalition of America
Nevada Public Utilities Commission	Sierra Pacific Power Company	16-06008	Depreciation rates, net salvage, theoretical reserve	Northern Nevada Utility Customers
Oklahoma Corporation Commission	Oklahoma Gas & Electric Co.	PUD 201500273	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201500208	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 201500213	Cost of capital, depreciation rates, net salvage	Public Utility Division

Proxy Group Summary

Company	Ticker	Market Cap. ($ millions)	Market Category	Value Line Safety Rank	Financial Strength
Atmos Energy Corporation	ATO	28,500	Large Cap	1	A
Chesapeake Utilities Corporation	CPK	3,100	Mid Cap	2	B++
New Jersey Resources Corporation	NJR	5,200	Mid Cap	2	A
NiSource Inc.	NI	21,300	Large Cap	2	B++
Northwest Natural Holding Company	NWN	2,000	Mid Cap	2	A
ONE Gas, Inc.	OGS	4,900	Mid Cap	2	A
Southwest Gas Holdings, Inc.	SWX	6,000	Mid Cap	2	B++

Value Line Investment Survey

DCF - Stock and Index Prices

Ticker	^GSPC	ATO	CPK	NJR	NI	NWN	OGS	SWX
30-day Average	6704	184.50	129.82	54.12	46.57	52.18	86.37	87.35
Standard Deviation	165.0	2.44	4.13	0.80	0.65	1.14	1.01	1.19
02/20/26	6910	179.97	133.69	52.78	46.37	50.11	85.52	87.60
02/23/26	6838	181.72	134.36	52.91	46.20	50.14	86.21	88.13
02/24/26	6890	182.02	134.34	53.18	46.42	50.12	85.39	88.00
02/25/26	6946	182.06	133.54	52.95	46.53	49.99	85.77	87.07
02/26/26	6909	183.63	133.91	53.09	46.70	50.27	86.54	88.41
02/27/26	6879	186.79	135.26	53.77	47.30	53.04	87.44	88.17
03/02/26	6882	187.07	136.49	54.01	47.05	52.59	87.37	88.50
03/03/26	6817	186.00	136.44	54.77	46.74	52.50	87.26	88.90
03/04/26	6870	186.77	136.94	54.75	47.56	52.53	87.70	89.60
03/05/26	6831	185.38	131.66	53.99	47.04	52.06	86.75	87.71
03/06/26	6740	185.04	131.56	54.05	46.46	52.10	87.05	87.62
03/09/26	6796	185.24	131.32	54.26	47.03	52.29	87.15	87.71
03/10/26	6781	183.44	128.36	53.84	46.57	51.62	86.23	87.01
03/11/26	6776	184.30	127.92	53.91	46.26	51.52	86.14	86.88
03/12/26	6673	186.79	128.54	54.32	46.69	51.94	86.89	87.32
03/13/26	6632	188.58	129.96	55.06	47.39	52.56	87.49	88.01
03/16/26	6699	187.82	130.43	54.90	47.47	52.67	86.99	88.28
03/17/26	6716	186.98	128.79	54.23	47.26	52.40	86.89	87.37
03/18/26	6625	185.25	127.38	53.28	46.62	52.62	85.85	86.28
03/19/26	6606	184.90	127.45	53.79	46.69	53.06	86.15	86.22
03/20/26	6506	180.49	123.55	52.86	45.02	51.42	83.87	83.58
03/23/26	6581	181.03	126.61	53.98	45.47	52.15	85.07	85.83
03/24/26	6556	181.57	124.50	54.21	45.68	52.25	85.57	86.35
03/25/26	6592	181.55	123.44	54.12	45.68	52.47	85.22	85.82
03/26/26	6477	183.18	124.38	54.67	45.44	52.86	85.79	86.57
03/27/26	6369	183.19	124.14	54.59	45.97	52.83	84.95	86.71
03/30/26	6344	185.02	126.16	55.44	46.50	53.62	86.17	87.31
03/31/26	6529	184.72	126.37	54.92	46.66	53.22	86.13	86.90
04/01/26	6775	185.49	127.71	54.99	46.90	53.70	86.56	87.51
04/02/26	6583	188.97	129.46	55.96	47.49	54.66	88.90	89.24

All prices are adjusted closing prices reported by Yahoo! Finance, http://finance.yahoo.com

DCF - Dividend Yields

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield
Atmos Energy Corporation	ATO	2.06	184.50	1.12%
Chesapeake Utilities Corporation	CPK	3.00	129.82	2.31%
New Jersey Resources Corporation	NJR	3.80	54.12	7.02%
NiSource Inc.	NI	1.96	46.57	4.21%
Northwest Natural Holding Company	NWN	2.28	52.18	4.37%
ONE Gas, Inc.	OGS	2.67	86.37	3.09%
Southwest Gas Holdings, Inc.	SWX	2.96	87.35	3.39%
Average		**$2.68**	**$91.56**	**3.64%**

[1] Yahoo Finance

[2] Average stock price from Exhibit DJG-3

[3] = [1] / [2]

DCF - Terminal Growth Rate Determinants

DCF Growth Rate Indicators	Rate
Nominal GDP (2026-2056)	3.8%
Real GDP	1.6%
Long-Term Growth Ceiling	**3.8%**

CBO, The 2026 Long-Term Budget Outlook (nominal annual GDP growth)

DCF - Final Result

Company	Ticker	[1] Dividend Yield	[2] Analyst Growth	[3] Sustainable Growth	[4] DCF Result (Analyst Growth)	[5] DCF Result (Sustainable Growth)
Atmos Energy Corporation	ATO	1.1%	8.0%	3.8%	9.2%	5.0%
Chesapeake Utilities Corporation	CPK	2.3%	6.5%	3.8%	9.0%	6.2%
New Jersey Resources Corporation	NJR	7.0%	6.0%	3.8%	13.4%	11.1%
NiSource Inc.	NI	4.2%	6.0%	3.8%	10.5%	8.2%
Northwest Natural Holding Company	NWN	4.4%	0.5%	3.8%	4.9%	8.3%
ONE Gas, Inc.	OGS	3.1%	2.0%	3.8%	5.2%	7.0%
Southwest Gas Holdings, Inc.	SWX	3.4%	1.5%	3.8%	4.9%	7.3%
Average		**3.6%**	**4.4%**	**3.8%**	**8.2%**	**7.6%**

[1] Dividend Yield from Exhibit DJG-4

[2] Forecasted dividend growth rates - Value Line

[3] Sustainable growth rate from Exhibit DJG-5

[4] Annual Compounding DCF = $D_0 (1 + g) / P_0 + g$ (using analyst growth rate)

[5] Annual Compounding DCF = $D_0 (1 + g) / P_0 + g$ (using sustainable growth rate)

CAPM - Risk-Free Rate Estimate

Date	Rate
04/02/26	4.88%
04/01/26	4.91%
03/31/26	4.88%
03/30/26	4.91%
03/27/26	4.98%
03/26/26	4.93%
03/25/26	4.89%
03/24/26	4.94%
03/23/26	4.91%
03/20/26	4.96%
03/19/26	4.83%
03/18/26	4.88%
03/17/26	4.85%
03/16/26	4.86%
03/13/26	4.90%
03/12/26	4.88%
03/11/26	4.86%
03/10/26	4.78%
03/09/26	4.72%
03/06/26	4.77%
03/05/26	4.74%
03/04/26	4.72%
03/03/26	4.70%
03/02/26	4.70%
02/27/26	4.64%
02/26/26	4.67%
02/25/26	4.70%
02/24/26	4.70%
02/23/26	4.70%
02/20/26	4.72%
Average	**4.82%**

*Daily Treasury Yield Curve Rates on 10-year T-bonds,
http://www.treasury.gov/resources-center/data-chart-center/interest-rates/

CAPM - Beta Coefficients

Company	Ticker	Beta
Atmos Energy Corporation	ATO	0.80
Chesapeake Utilities Corporation	CPK	0.75
New Jersey Resources Corporation	NJR	0.75
NiSource Inc.	NI	0.85
Northwest Natural Holding Company	NWN	0.80
ONE Gas, Inc.	OGS	0.75
Southwest Gas Holdings, Inc.	SWX	0.80
Average		0.79

Value Line Investment Survey

CAPM - Implied Equity Risk Premium Estimate

Year	[1] Market Value	[2] Operating Earnings	[3] Dividends	[4] Buybacks	[5] Earnings Yield	[6] Dividend Yield	[7] Buyback Yield	[8] Gross Cash Yield
2014	18,245	1,004	350	553	5.50%	1.92%	3.03%	4.95%
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%
2020	31,659	1,019	480	520	3.22%	1.52%	1.64%	3.16%
2021	40,356	1,739	511	882	4.31%	1.27%	2.18%	3.45%
2022	32,133	1,656	565	923	5.15%	1.76%	2.87%	4.63%
2023	36,870	1,790	588	795	4.85%	1.60%	2.16%	3.75%
2024	49,805	1,967	630	943	3.95%	1.26%	1.89%	3.16%

Cash Yield	4.36%	[9]
Growth Rate	6.95%	[10]
Risk-free Rate	4.82%	[11]
Current Index Value	6,704	[12]

Year	[13] 1	[14] 2	[15] 3	[16] 4	[17] 5
Expected Dividends	312	334	357	382	409
Expected Terminal Value					8555
Present Value	285	277	270	263	5610
Intrinsic Index Value	6704	[18]			
Required Return on Market	9.8%	[19]			
Implied Equity Risk Premium	**5.0%**	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500 (additional info tab) (all dollar figures are in $ billions)
[1] Market value of S&P 500
[5] = [2] / [1]
[6] = [3] / [1]
[7] = [4] / [1]
[8] = [6] + [7]
[9] = Average of [8]
[10] = Compund annual growth rate of [2] = (end value / beginning value)^ $^{1/10}$-1
[11] Risk-free rate from DJG risk-free rate exhibit
[12] 30-day average of closing index prices from DJG stock price exhibit
[13-16] Expected dividends = [9]*[12]*(1+[10])^{n} ; Present value = expected dividend / (1+[11]+[19])^{n}
[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19])^{n}
[18] = Sum([13-17]) present values.
[19] = [20] + [11]
[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

CAPM - Equity Risk Premium Results

IESE Business School Survey	5.5%	[1]
Kroll (Duff & Phelps) Report	5.0%	[2]
Damodaran (average)	5.0%	[3]
Garrett	5.0%	[4]
Average	**5.1%**	

CAPM - Final Results

Company	Ticker	[1] Beta	[2] CAPM Result
Atmos Energy Corporation	ATO	0.80	8.9%
Chesapeake Utilities Corporation	CPK	0.75	8.7%
New Jersey Resources Corporation	NJR	0.75	8.7%
NiSource Inc.	NI	0.85	9.2%
Northwest Natural Holding Company	NWN	0.80	8.9%
ONE Gas, Inc.	OGS	0.75	8.7%
Southwest Gas Holdings, Inc.	SWX	0.80	8.9%
Average			**8.8%**
Risk-free Rate	[3]	4.8%	
Equity Risk Premium	[4]	5.1%	

[1] From Exhibit DJG-8

[2] = [3] + [1] * [4]

[3] From Exhibit DJG-7

[4] From Exhibit DJG-10

Cost of Equity Summary

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	8.8%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.5%
DCF Model (Analyst Growth)	8.2%
DCF Model (Sustainable Growth)	7.6%
Model Average	**8.3%**
Recommended ROE	**8.8%**

Proxy Company Debt Ratios

Company	Ticker	Debt Ratio
Atmos Energy Corporation	ATO	40%
Chesapeake Utilities Corporation	CPK	49%
New Jersey Resources Corporation	NJR	58%
NiSource Inc.	NI	56%
Northwest Natural Holding Company	NWN	55%
ONE Gas, Inc.	OGS	43%
Southwest Gas Holdings, Inc.	SWX	55%
Average		51%

Debt ratios from Value Line Investment Survey - 2025

Competitive Industry Debt Ratios

Industry	# Firms	Debt Ratio
Retail (Building Supply)	14	97%
Restaurant/Dining	64	95%
Hotel/Gaming	63	82%
Brokerage & Investment Banking	32	79%
Retail (Automotive)	34	77%
Hospitals/Healthcare Facilities	31	76%
Rubber& Tires	3	74%
Bank (Money Center)	15	73%
Recreation	49	72%
Air Transport	23	71%
Food Wholesalers	13	69%
Retail (Grocery and Food)	15	67%
Chemical (Diversified)	4	66%
Cable TV	9	65%
Telecom (Wireless)	12	65%
Advertising	52	64%
Transportation	19	64%
R.E.I.T.	190	63%
Power	46	63%
Oil/Gas Distribution	23	63%
Transportation (Railroads)	4	62%
Computers/Peripherals	36	61%
Telecom. Services	39	61%
Broadcasting	24	61%
Auto & Truck	33	60%
Retail (Special Lines)	94	60%
Software (Internet)	29	60%
Green & Renewable Energy	15	59%
Environmental & Waste Services	53	58%
Office Equipment & Services	14	58%
Utility (General)	14	58%
Beverage (Soft)	27	57%
Apparel	35	56%
Information Services	15	56%
Retail (Distributors)	62	55%
Utility (Water)	14	55%
Farming/Agriculture	35	55%
Aerospace/Defense	79	55%
Packaging & Container	19	54%
Computer Services	64	54%
Retail (REITs)	26	54%
Chemical (Basic)	29	52%
Furn/Home Furnishings	27	52%
Business & Consumer Services	155	51%
Household Products	110	51%
Drugs (Biotechnology)	496	51%
Real Estate (Development)	14	50%
Total / Average	**2,273**	**63%**

http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/dbtfund.htm

Hamada Model Results

Unlevering Beta

Proxy Debt Ratio	51%	[1]
Proxy Equity Ratio	49%	[2]
Proxy Debt / Equity Ratio	1.0	[3]
Tax Rate	21%	[4]
Equity Risk Premium	5.1%	[5]
Risk-free Rate	4.8%	[6]
Proxy Group Beta	0.79	[7]
Unlevered Beta	0.43	[8]

Relevered Betas and Cost of Equity Estimates

[9] Debt Ratio	[10] D/E Ratio	[11] Levered Beta	[12] Cost of Equity
0%	0.0	0.43	7.0%
20%	0.3	0.52	7.5%
25%	0.3	0.54	7.6%
30%	0.4	0.58	7.8%
46%	0.8	0.72	8.5%
51%	1.0	0.79	8.8%
60%	1.5	0.94	9.6%

[1] Proxy group average debt ratio

[2] Proxy group average equity ratio

[3] = [1] / [2]

[4] Company assumed tax rate

[5] Equity risk premium from Exhibit DJG-11

[6] Risk-free rate from Exhibit DJG-11

[7] Average proxy beta from Exhibit DJG-11

[8] = [7] / (1 + (1 - [4]) * [3])

[9] Various debt ratios (Garrett proposed highlighted)

[10] = [9] / (1 - [9])

[11] = [8] * (1 + (1 - [4]) * [10])

[12] = [6] + [11] * [5]

Final Rate of Return Recommendation

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	51.0%	5.17%	2.64%
Common Equity	49.0%	8.80%	4.31%
Total	100.0%		6.95%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, David J. Garrett, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 13, 2026

Signature: */s/ David J. Garrett*
David J. Garrett

Address: 101 Park Avenue
Suite 1125
Oklahoma City, OK 73120

OCA St. 3SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, et al.	**:**	
v.	**:**	**Docket No. R-2025-3059523**
UGI Utilities, Inc. – Gas Division	**:**	

SURREBUTTAL TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2026

Q. State your name and occupation.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting PLLC.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed direct testimony in OCA Statement 3 on April 13, 2026, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). A summary of my qualifications is included in my direct testimony.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the rebuttal testimony of UGI Utilities, Inc. – Gas Division's ("UGI" or the "Company") witness Dylan D'Ascendis regarding rate of return issues.

Q. Did the Company's rebuttal testimony cause you to change any of your positions or recommendations discussed in your direct testimony?

A. No. To the extent I do not specifically address a statement made in the Company's rebuttal testimony filed in this case, it should not constitute my agreement with such testimony.

Q. Are you sponsoring any exhibits to your surrebuttal testimony?

A. No.

Q. Please summarize your surrebuttal testimony directed to the rebuttal testimony of Mr. D'Ascendis.

A. In my surrebuttal testimony, I address Mr. D'Ascendis's updated cost of equity results. I will also address the assertions made in his rebuttal testimony regarding capital structure, the Discounted Cash Flow ("DCF") Model, and the Capital Asset Pricing Model ("CAPM").

A. Updated Cost of Equity Analysis

Q. Please summarize Mr. D'Ascendis's updated cost of equity analysis.

A. Mr. D'Ascendis conducted an updated cost of equity analysis. Based on this analysis, Mr. D'Ascendis concludes his original recommended ROE of 10.75% is reasonable.[1]

Q. Does Mr. D'Ascendis's updated cost of equity analysis indicate a reasonable authorized ROE for UGI?

A. No. Mr. D'Ascendis used substantially similar assumptions and methods in his updated ROE analysis as he did in his original ROE analysis. Thus, the criticisms raised in my direct testimony regarding Mr. D'Ascendis's original ROE analysis also apply to his updated ROE analysis.

Q. Mr. D'Ascendis removed Chesapeake Utilities from the proxy group in his updated analysis. Would removing Chesapeake from your proxy group have any material impact on your results?

A. No. If I conducted the same cost of equity and capital structure analysis without Chesapeake in the proxy group, it would have no impact on my cost of capital estimates or rate of return recommendation.

B. Capital Structure

Q. Please summarize Mr. D'Ascendis's criticisms of your capital structure adjustment.

A. Mr. D'Ascendis claims that UGI's proposed capital structure is reasonable because it is within a range of other operating subsidiary capital structures.[2]

---

[1] Rebuttal Testimony of Dylan D'Ascendis, p. 5.

[2] Rebuttal Testimony of Dylan D'Ascendis, p. 10, lines 5-19.

Q. What is your response to Mr. D'Ascendis's rebuttal testimony on this issue?

A. My capital structure adjustment simply aligns UGI's capital structure with the average capital structure of Mr. D'Ascendis's own proxy group. The average debt ratio of Mr. D'Ascendis's own proxy group is 51%. To accept a debt ratio less than this for the purpose of calculating the ROR essentially amounts to cherry-picking the metrics of the proxy group to obtain a more favorable ROR for the Company. This is because there is a direct relationship between risk and cost of equity. The more financial risk (or debt) a company has in its capital structure, it will have an increasing effect on its cost of equity. The fact that UGI has less debt in its capital structure relative to the proxy group is significant, and it means that UGI has less financial risk than the proxy group. Since we are obtaining all of the other metrics used to estimate UGI's cost of equity from the proxy group, it would be inaccurate to reject the capital structure of that same proxy group as part of the analyses. The Hamada model I used in this case mathematically reconciles the discrepancy between UGI's low debt ratio relative to the proxy group's average. In that regard, the authorized ROE I propose for UGI is very reasonable.

Q. Does your proposed capital structure adjustment acknowledge the issues raised in Governor Shapiro's letter to utility leaders?

A. Yes. In his letter to utility leaders dated April 29, 2026, Governor Shapiro stated:

> [D]ebt should normally represent a clear majority of a utility's proposed ratemaking capital structure, as it does in many other lower-risk industries. As one measure of this approach, any equity share proposed in a rate case in excess of the amount of equity employed by the utility's parent holding company will require extraordinary justification to receive my Administration's support.[3]

In my experience, utilities with parent-subsidiary structures commonly employ a double leverage strategy, in which more debt is held at the parent level, while the subsidiary has more equity. However, the "equity" on the subsidiary's balance sheet is funded by the debt of the parent company, which ultimately allows the regulated subsidiary to earn a high equity return on the parent's low-cost debt. This results in an unfair boon for shareholders at the expense of customers. More specifically, it results in an even higher authorized return above the utility's market based required return (i.e., cost of equity). As discussed in my direct testimony, the following tables show a summary of my capital structure analysis in this case.

[3] Office of the Governor, Letter to Utility Leaders (April 29, 2026).

Figure 1:
Capital Structure Analysis Summary

Industry / Company	Debt Ratio
Cable TV Industry	65%
Power Industry	63%
Telecom Services Industry	61%
UGI Parent Company	**58%**
Proxy Group of Utilities	**51%**
Company Proposed	**46%**

I agree with the Governor's assessment of this issue. In order to more fully eliminate the unfair advantage double leverage provides the utility, the subsidiary's ratemaking debt ratio would be the same as the parent company's debt ratio. In this case, that would mean UGI's ratemaking debt ratio would be 58%. In that regard, my proposed ratemaking debt ratio in this case of only 51% (to match the proxy group average) is very reasonable and would at least partially mitigate the unfair aspects of double leverage.

C. DCF Model.

Q. Please summarize Mr. D'Ascendis's criticisms of your DCF Model

A. Mr. D'Ascendis states "it appears that Mr. Garrett places no weight on his DCF model results in arriving at his recommendation in this proceeding. . . ."[4]

[4] Rebuttal testimony of Dylan W. D'Ascendis, pp. 43-44.

Q. What is your response to Mr. D'Ascendis regarding this issue?

A. While it is correct that my authorized ROE recommendation of 8.8% is the same as the result of my CAPM, this does not mean the DCF Model results of 8.2% and 7.6% (for the analyst-growth and sustainable-growth variations) are irrelevant. The DCF Model results indicate the Company's market-based cost of equity is likely lower than 8.8%. In fact, the average result of my various CAPM and DCF Models is only 8.3%.[5] Thus, if the DCF Model results are viewed as relative measure of reasonableness for the CAPM results, they indicate the CAPM results may actually be too high. Thus, the DCF Model results indicate the Company's authorized ROE should be no higher than 8.8%, because that is the highest reasonable estimate of the Company's market-based cost of equity.

D. CAPM Analysis

Q. Please summarize Mr. D'Ascendis's criticisms of your CAPM analysis.

A. Mr. D'Ascendis primarily disagrees with my equity risk premium ("ERP") estimate, which is a key input to the CAPM. He also disagrees with my application of the Hamada variation of the CAPM.[6]

Q. Please briefly reiterate the sources you considered for the ERP estimate.

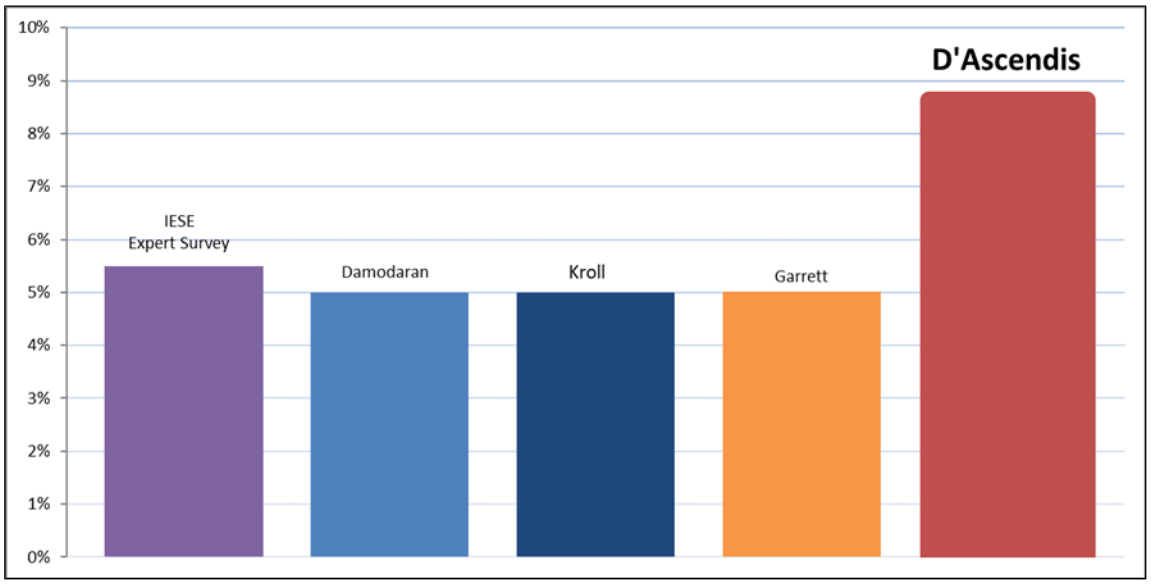
A. The ERP is an important figure for financial and market analysts in all industries, not just utility regulation. Thus, many analysts, managers, investors, and academics are constantly studying and are concerned with obtaining a reliable and accurate estimate of this important number, which can be used in a variety of financial analyses, including the CAPM. All

[5] Exhibit DJG-12.

[6] *Id*. at pp. 44-52.

else held constant, a higher ERP will result in a higher indicated cost of equity and apply upward pressure on the authorized ROE. I considered three reliable and objective sources to include in my overall ERP estimate, including the result of the IESE Business School survey of experts, the estimate published by Kroll (formerly Duff & Phelps), and the estimate published by one of the world's leading experts on the issue, Dr. Aswath Damodaran. I also conducted and presented my own ERP estimate, the result of which is similar to those from the other sources. The figure below contrasts the ERP estimates from these sources with the ERP estimated by Mr. D'Ascendis.[7]

Figure 2:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP (as well as my estimate), which do not have a wide variance, Mr. D'Ascendis's ERP estimate is clearly not within

[7] *See also* Exhibit DJG-10.

the range of reasonableness. Mr. D'Ascendis offers various criticisms of these sources, and basically argues the Commission should accept his estimate over the opinions of hundreds of CEOs, CFOs, scholars, and an international corporate finance advising company. I would argue that investors are more likely to rely on these types of sources for the ERP than Mr. D'Ascendis's personal ERP estimate. Effectively, Mr. D'Ascendis is suggesting the Commission should adopt his ERP estimate over the opinions of thousands of unbiased experts, Kroll (a global financial advisory firm), and one of the world's leading experts on the ERP.

Q. Mr. D'Ascendis argues that the ERP reported by the expert survey, Kroll, and Dr. Damodaran did not accurately predict the return on the market. What is your response?

A. Mr. D'Ascendis's arguments on this issue attempt to conflate two different metrics. An expected return on a stock or index of stocks based on market risk is very different concept than an earned return. An earned return by a company, group of companies, or an entire market may fluctuate widely from year to year, similar to the boom-bust cycle of the economy. However, this does not have a direct impact on the required return of investors, which will be much more stable over time. For example, during the recession of 2008, the market had a negative return of about 40%. However, it would be impossible for an expected return or ERP estimate to ever be negative. According to Mr. D'Ascendis's logic, however, anyone during 2008 who estimated a positive ERP, required return, or cost of equity estimate would have made an error. Earned returns and expected returns are entirely different concepts. An equity risk premium is not a prediction or forecast of market performance.

Q. Mr. D'Ascendis claims your implied ERP model does not take into account capital appreciation, growth in dividends, or buy backs into your calculated growth rate. What is your response.

A. First, the result of my application of the implied ERP model produced the exact same result as recent ERP estimates published by both Dr. Damodaran and Kroll, which are objective, respected sources for ERP. This indicates my ERP estimate is reasonable. Furthermore, my implied ERP model effectively applies a DCF application to the S&P 500, which is not materially different than applying the DCF Model to a single company. Instead of solving for the price, we are solving for the discount rate (i.e., the implied cost of equity). My implied ERP model does in fact take into account stock buybacks in addition to dividends (because failing to account for buybacks could understate the "cash flow" that investors would have received if only dividends were considered).[8] Regarding Mr. D'Ascendis's claim that the model does not account for market appreciation, this is not a valid criticism of the model. Like the DCF Model, the implied ERP model is discounting a stream of cash flows (i.e., dividends and buybacks), which has an annual growth rate, back to the present market value. The result of this model indicates an implied discount rate (i.e., equity risk premium).

Q. Mr. D'Ascendis disagrees with your testimony that investors do not expect a return for assuming firm-specific business risks. What is your response?

A. I thoroughly discuss this issue in my direct testimony. The concept that investors do not expect a return for assuming firm-specific business risk is a cornerstone of modern portfolio theory and the CAPM (as thoroughly discussed and cited in my direct testimony).

[8] Exhibit DJG-9 (column [7] shows the buyback yield).

Moreover, in the case of a regulated monopoly such as UGI, the firm-specific risk is even lower because the utilities do not have the same type of bankruptcy risk or failure risk that a typically company would have. Effectively, utilities such as UGI have a social safety net provided by the government and their customers that would prevent them from experiencing a complete financial failure. In that regard, it is not unreasonable to assume the utility's required return on equity would be materially higher than its cost of debt, because there is no reasonable, foreseeable scenario in which shareholders are standing in line behind bondholders in a bankruptcy proceeding. So to the extent firm-specific risk should be considered, as Mr. D'Ascendis is implying, it would only reduce UGI's cost of equity even further.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, David J. Garrett, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2026

Signature: */s/ David J. Garrett*
David J. Garrett

Address: 101 Park Avenue
Suite 1125
Oklahoma City, OK 73120

BEFORE THE

PENNSYLVANIA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PENNSYLVANIA PUBLIC UTILITY COMMISSION V. UGI UTILITIES, INC. – GAS DIVISION	* * * * *	**DOCKET NUMBER R-2025-3059523, et al.**

DIRECT TESTIMONY AND EXHIBITS

OF

JAMES S. GARREN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

APRIL 13, 2026

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LIST OF EXHIBITS

Exhibit JSG-1. Resume – James S. Garren

Exhibit JSG-2. Calculation of depreciation rates and accruals.

Exhibit JSG-3. Remaining life calculations

I. INTRODUCTION

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

A. My name is James S. Garren. I am a Senior Manager of the firm NewGen Strategies and Solutions LLC ("NewGen"). My business address is 225 Union Boulevard, Suite 450, Lakewood, CO 80228.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Exhibit JSG-1 is a summary of my qualifications and experience.

Q. PLEASE DESCRIBE YOUR BACKGROUND IN UTILITY DEPRECIATION.

A. Since 2010, I have been employed in the utility consulting field, beginning my career as an analyst with Snavely King Majoros & Associates, Inc. My early work focused on depreciation studies, where I supported Michael J. Majoros in preparing testimony and exhibits for depreciation proceedings. In 2014, I became the firm's primary expert on depreciation matters. Since that time, I have presented testimony in numerous depreciation rate cases across the United States, addressing issues such as service life estimation, net salvage analysis, reserve analysis, and related depreciation topics. In 2015, I earned the designation of Certified Depreciation Professional from the Society of Depreciation Professionals.[1] From 2022 to 2025, I served as a Project Manager with GDS Associates, Inc., continuing my work as a depreciation expert. In October 2025, I joined NewGen, where I continue to provide expert analysis and testimony on depreciation issues.

[1] https://www.depr.org/page/Certification

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. UGI Utilities, Inc.'s gas division ("UGI" or "Company") has filed a petition with the Pennsylvania Public Utilities Commission ("Commission") for approval of new rates. As a part of its filing, it has included depreciation testimony and a depreciation study completed by John Wiedmayer of Gannett Fleming. As a result of his study, Mr. Wiedmayer has proposed average service lives and a net salvage allowance, which make up his proposed depreciation rates. The OCA has asked me to review Mr. Wiedmayer's testimony and study to determine whether any adjustments are needed to Mr. Wiedmayer's proposed depreciation rates to ensure that they are appropriate.

II. SUMMARY

Q. CAN YOU SUMMARIZE THE CONCLUSIONS FROM YOUR TESTIMONY?

A. Based on my recommended depreciation parameters, depreciation accruals produce a depreciation expense of $149.7 million for UGI's gas plant. The Company proposes a depreciation expense of $170.5 million. I therefore conclude that the Company has overstated its depreciation expense by $20.8 million. My conclusion is based on UGI's proposed parameters based on data available as of September 30, 2026 plant balances used for the future test year, which is the period on which the service life analysis was conducted. My recommended depreciation rates are lower than those used by UGI witness John Wiedmayer. This is due to my proposed adjustments to the Company's depreciation rate calculation. My adjustments include:

1. Conversion to the use of Average Life Group remaining life procedure for vintages after 1982.

2. Adjustments to service lives for plant account (Account number375 – Structures and Improvements, 376.1 – Mains, Primarily Steel & 378, Measuring and Regulating Equipment, General).

The table below summarizes the impact of my proposed adjustments on the depreciation rates and expenses by function:

Table JSG-1
Summary of Depreciation Rates and Expenses ($) in millions
Based on September 30, 2026Plant Balances

Function	Wiedmeyer Expense	Wiedmeyer Rate	OCA Expense	OCA Rate	Difference
Gas	$140.6	2.75%	$149.7	2.41%	$20.8

Q. WHAT INFORMATION HAVE YOU REVIEWED IN PREPARATION FOR THIS TESTIMONY?

A. I reviewed UGI's gas plant depreciation studies and then prepared data requests, which the OCA served on UGI. I reviewed UGI's responses to discovery, the documents attached to UGI's filing, and the data relied upon by Mr. Wiedmayer to perform his depreciation studies. Utilizing this data and applying my own independent analysis, I recommend adjustments to the depreciation rates and accruals utilized for plant depreciation.

III. DEPRECIATION – GENERAL

Q. WHAT IS DEPRECIATION AS APPLIED TO DEPRECIABLE UTILITY PLANT?

A. In 1958, the National Association of Regulatory Utility Commissioners ("NARUC")

sanctioned the following definition: "Depreciation," as applied to depreciable utility plant, means:

> the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[2]

Another commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:[3]

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

In short, depreciation is the process of recovering the initial investment in tangible capital assets in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. CAN DEPRECIATION BE CALCULATED WITH PRECISION?

A. No. Because it requires an estimation of the total and remaining service life of plant, a determination of depreciation rates cannot be calculated with precision. However, to ensure the analysis is as accurate as is reasonably possible, the determination of depreciation rates

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[2] National Association of Railroad and Utilities Commissioners, *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.

[3] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1.*

requires the knowledge and informed judgment of an expert trained in the field of utility depreciation. The judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements, industry trends, and corporate investment plans.

One of the practical goals of performing a depreciation study is to reduce the negative impact of inevitable errors in the estimation of average service lives and retirement curves over the long run. One reason for the rapid adoption of the remaining life method of depreciation is that it is self-correcting of the inevitable errors made in the process of estimation. One of the dangers of depreciation is in assuming a greater degree of precision in our estimates than is realistic and using methodologies that might over-collect or under-collect depreciation to the point that reserves need to be rebalanced, even with the use of remaining life. When we assume that estimates are precise and commit to procedures and calculations that produce more extreme results based on that assumption of precision, the impact of errors in estimates ultimately produces rate shock for consumers when corrections need to be made. Because these rate shocks are considered particularly harmful for consumers, a principle of moderation is considered preferable to adopting policies or depreciation parameters that result in extreme shifts in depreciation expense over time.

Q. WHAT ARE THE BASIC PARAMETERS USED TO DEVELOP A DEPRECIATION RATE?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the asset being retired. The reciprocal of that number can be used as the depreciation rate (*i.e.*, the number one divided by the estimated service life of the asset).

Virtually all utilities use what is known as "remaining life" depreciation. This "remaining life procedure" computes the depreciation rate by dividing the unrecovered net investment by the estimated remaining years of the asset's (or group of assets') service life. It is intended to ensure that any past under-accruals or over-accruals of depreciation are recovered during the remaining life of the asset.

The remaining life procedure requires an estimate of the dispersion of retirements around an average service life. In the utility industry, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the company's retirements are grouped around the average service life and whether the retirements tend to occur more rapidly before, after, or coincident with the average service life.[4] I discuss Iowa curves in more detail in a later section of this testimony.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATON RATES.

A. Beginning with a simple example, assume a single asset with a 20-year life.[5] Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume the asset is expected to have salvage value equivalent to 5 percent of its investment value.[6] The depreciation rate declines:

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[4] For a complete discussion of Iowa Curves, see Appendix A, part 3 of *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners, August 1996.

[5] This example is only to illustrate basic principles. As I explain in the next section, there are primarily *groups* of assets rather than a single asset, with each asset group assigned to an account. Thus, this example is not illustrative of how depreciation is actually calculated in current practice.

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional points of data: the original cost of the asset, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost less 5 percent positive salvage, or $50,000 so that the total amount yet to be recovered is $550,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life:

$$\frac{\$550{,}000}{10 \text{ years}} = \$55{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this example:

$$\$55{,}000 / \$1{,}000{,}000 = 5.5\%$$

IV. PLANT SERVICE LIFE

Q. PLEASE DEFINE "AVERAGE SERVICE LIFE" AS IT IS USED IN UTILITY DEPRECIATION CALCULATIONS.

A. The "average service life" for a given account is a projection of the number of years that a new unit of plant can be expected to remain used and useful on average. This concept is useful because modern depreciation utilizes what is called "group depreciation." That is,

rather than depreciate the value of an individual unit or units over the lifetime of those units, the value of a collection of units all together is depreciated. This group depreciation assumes that many units in each account will be retired at earlier ages, and thus have shorter than average lives, and many units will retire at later ages, and thus have longer than average lives. Average service life is used to calculate the average remaining life, which, in turn, is the denominator in the calculation of depreciation expense. Group depreciation is also why the lives of units in an account are not studied, but rather, one analyzes the lives of dollars in these accounts.

Q. DOES THE LENGTH OF A UTILITY PLANT'S SERVICE LIFE AFFECT RATES?

A. Yes. As a general matter, shorter service life estimates for utility plant result in higher depreciation rates and expense for customers.

Q. PLEASE DESCRIBE THE PROPER WAY TO DETERMINE THE AVERAGE SERVICE LIFE COMPONENT OF DEPRECIATION RATES.

A. I have analyzed UGI's accounts using an actuarial life analysis process called the Retirement Rate method. Actuarial methodologies were developed initially in the 17th and 18th centuries, primarily by life insurance companies that needed a mathematical means of estimating the mortality risk of individuals over a long period of time. This resulted in the development of "life tables" that show the mortality risk of a group of individuals with similar risk factors at each age.

The Retirement Rate method is an actuarial technique used to study plant lives, much like the actuarial techniques used in the insurance industry to study human lives. It requires an accurate record of the dates of placement and retirement for each asset studied.

Retirement data that includes the date of placement and retirement is referred to as "aged data" because it tells the analyst the age of the plant at the time it was retired. The Retirement Rate method is the most sophisticated of the statistical life analysis methods because it relies on the most refined level of data.

The Retirement Rate method uses (1) the aged retirement data as described in the previous paragraph and (2) total plant in service at a given age (referred to collectively as "exposures") from a company's records to construct an "observed" or "original life table" ("OLT"). I discuss the composition of an observed life table in detail below. Observed life tables are important because they result in data points showing the percentage of a given unit of plant that is expected to survive to a given age. The actuarial analysis smooths and extends the OLT by pairing it with one of a family of 31 standardized survivor curves, which are the Iowa curves that I previously mentioned. The curve-fitting uses the least squared differences approach to find a best fit life for each curve. The "sum of least squared difference" is a common means of fitting curves (in this case the Iowa curves) to a set of data (in this case the observed life table data). The difference between each point of data and a point on a line is squared,[7] and the square of all those differences is summed to provide the total difference between the set of data and the line. The line that produces the least difference from the set of data is considered the "best fit." The purpose of squaring

[7] "Square" in mathematics means you multiply a quantity by itself. This quantity can be a number, variable or even an algebraic expression. When you square a number, the answer will always be positive; thus, the product of a negative number multiplied by another negative number equals a positive number. Squaring is the same as raising to the power 2, and is denoted by a superscript 2; for instance, the square of 3 may be written as 3^2, which is the number 9.

the difference is to ensure that differences both above and below the actual retirement data contribute to the overall fit index, rather than canceling each other out.

Numerous iterative calculations are required for a Retirement Rate analysis. In the end, the analysis produces a life and Iowa curve best fit for a single average vintage. However, finding a mathematical best fit is only the beginning of the process of determining the most appropriate average service life and remaining life curve for a given account.

Q. PLEASE EXPLAIN THE ROLE OF INFORMED JUDGMENT IN DETERMINING THE APPROPRIATE SERVICE LIFE FOR AN ACCOUNT.

A. The term 'informed judgment' is what is used by NARUC's "*Public Utility Depreciation Practices," August 1996, ("Depreciation Practices")* to incorporate a number of different factors of consideration for a depreciation expert in determining appropriate depreciation parameters:

1. Observable trends reflected in historical data,
2. Potential changes in the type of property installed,
3. Changes in the physical environment,
4. Changes in management requirements,
5. Changes in government requirements, and
6. Obsolescence due to the introduction of new technologies.[8]

So, in the first place, we can see the very first factor that is intended to be incorporated into informed judgment is, in fact, the historical analysis of the data.

On the importance of informed judgment, *Depreciation Practices* states:

> The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and

[8] National Association of Regulatory Utility Commissioners, "Public Utility Depreciation Practices," August 1996, at 128.

> weighed by importance. For example, the following forces of retirement need to be considered: Do the past and current service life dispersions represent the future? Will scrap prices rise or fall? What will be the impact of future technological obsolescence? Will the company be in existence in the future? The analyst must rank the factors and decide the relative weight to apply to each. The final estimate might not resemble anyone of the specific factors; however, the result would be a decision based upon a combination of the components.[9]

This makes clear that it is, and should be, impossible to separate the process of determining appropriate depreciation parameters from the subjective factors that a depreciation expert must consider, above and beyond the mathematical analysis.

However, *Depreciation Practices's* discussion of informed judgment should be viewed in its full context. The section of *Depreciation Practices* entitled, "Informed Judgment," which is part of a larger section on the technical interpretation of actuarial analysis, comprises just over one page of a more than three-hundred and fifty page treatise that focuses on the various modes of mathematical analysis considered appropriate for the evaluation of historical data and the mathematical projection of historical trends into the future. Almost the entirety of *Depreciation Practices* focuses on the interpretation of and the outcome of the statistical analysis, which is the foundation of UGI's study. The "Informed Judgement" section of the *Depreciation Practices* is intended to provide *additional* context addressing when adjustments may be necessary *outside* of the historical life analysis. Importantly, when a depreciation expert applies *informed judgment*, it should be clearly explained what factors weighed into the assessment, and rooted, to the extent possible, in concrete data.

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[9] *Id.* at 129.

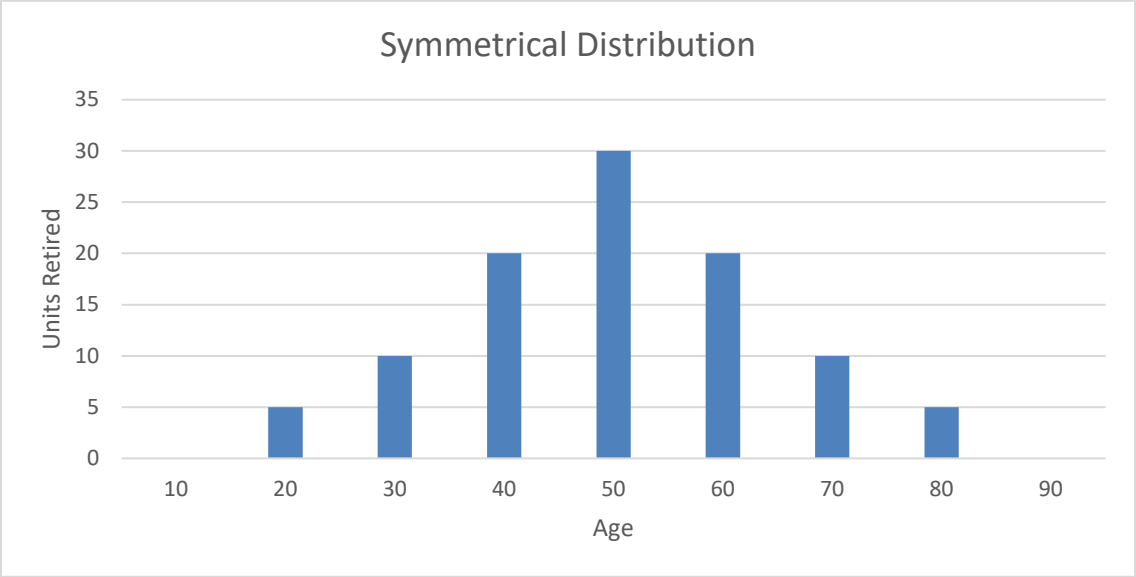
Q. PLEASE FURTHER EXPLAIN IOWA CURVES.

A. An Iowa curve is a surrogate or standardized "OLT" based on a specific pattern of retirements around an average service life. An "OLT" is a table listing the percent surviving (in other words, the "observed life") of a common class of assets, as of a particular calendar year. The Iowa curves are standardized OLTs that provide a set of standard patterns of retirement dispersion. Retirement dispersion recognizes that accounts are comprised of individual assets or units having different lives. Each curve represents a probability distribution and has a series of attributes. The curves are helpful in a variety of ways, including:

- To make realistic forecasts of the remaining useful life of groups of assets.
- To assist in anticipating the potential failure and functional failure of assets.

For example, imagine an account that begins with a new addition of one hundred units. These units are unlikely to all retire at the same time. Rather, different units within the group will retire at different times. Represented graphically, the result might appear as follows:

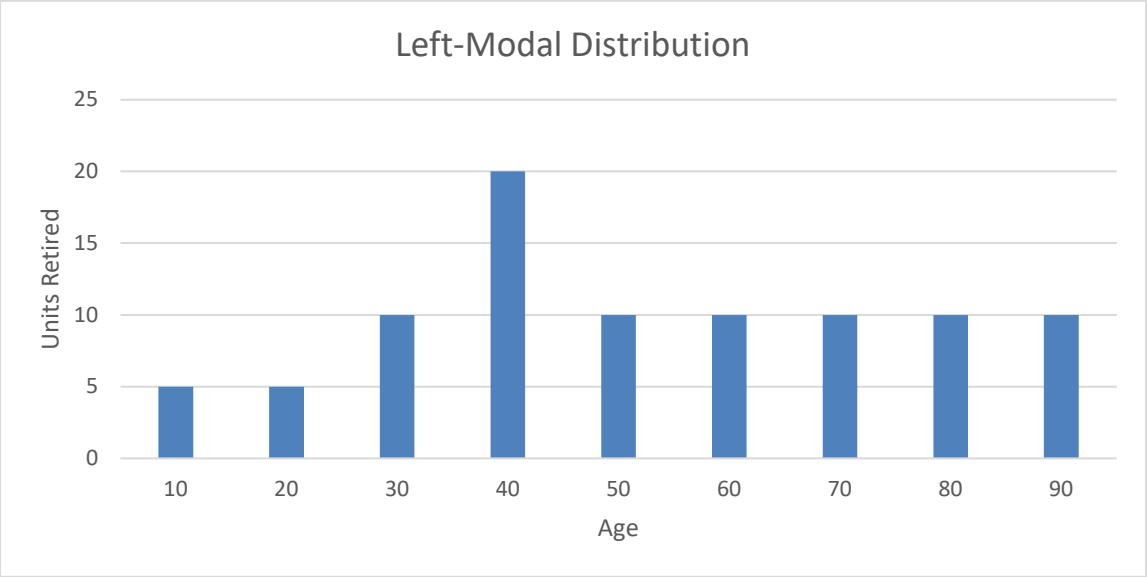
Graph JSG-1



In this example, the average service life would be fifty years, and the retirement dispersion curve would tell us how the retirements are arranged around the average service life. In this example, the distribution of retirements around the average service life is symmetrical, with the "mode" – that is, the age with the highest number of retirements – being at the average service life. In this data, the retirements are also relatively tightly grouped around the average service life.

Iowa curves describe many different patterns of dispersions. Returning to our example, imagine a different pattern of retirements as follows:

Graph JSG-2



In this example, the average service life is still fifty, but the dispersion characteristics are very different. The mode (again, the highest number of retirements) is at age 40, which is an earlier age than the average, and overall, the distribution of retirements is more spread out than in the previous example. By using different types of Iowa curves, an expert can capture these different retirement characteristics evident in retirement data.

One way that Iowa curves illustrate these different patterns is by their orientation as left-skewed ("L curves"), symmetrical ("S curves") or right-skewed curves ("R curves"). The letters describe the location of the "mode," as discussed above, relative to the average service life. Hence, in the first example, I would use an "S curve" because the number of retirements is relatively equal on both sides of the mode. In the second example, however, in which the mode falls before the average service life (that is, the mode falls at a younger

age than the average service life), I would use an "L curve." If the mode were to fall after the average service life, then I would use an "R curve."[10]

In addition to the letter that describes the location of the mode (e.g., L curve), Iowa curves are numbered zero (0) through six (6). The numbering identifies the spread of the retirement dispersion. Lower numbers represent a wider retirement dispersion while higher numbers represent a narrower dispersion. Referring to the first example above, in which the retirements were more tightly grouped around the average service life, a higher number would be used, whereas in the second example, where the retirements were not tightly grouped around the average service life, a lower number would be used.

To combine these two concepts, an appropriate Iowa curve for the first example might be an S5, where the "S" indicates a symmetrical curve to either side of the mode and the 5 indicates a relatively narrow dispersion of retirements. In contrast, for the second example, the data indicate a more likely curve of L2, with an "L" because the mode falls before the average service life and a "2" because there is a relatively wider retirement dispersion. This combination of one letter and one number defines a dispersion pattern. Adding an average service life to an Iowa curve (*e.g.*, 5-S0, where the "5" represents a five-year average service life) provides a survivor curve intended to depict a reasonable expectation of how a group of assets will survive, or conversely be retired, over the expected average service life.

[10] In addition to L, S and R curves, there is a set of Origin Modal, or "O curves," which are so called because the mode for these curves is at age one, or the "origin." Generally speaking, O-shaped Iowa curves are not appropriate for utility plant, although one of them in this particular instance is required.

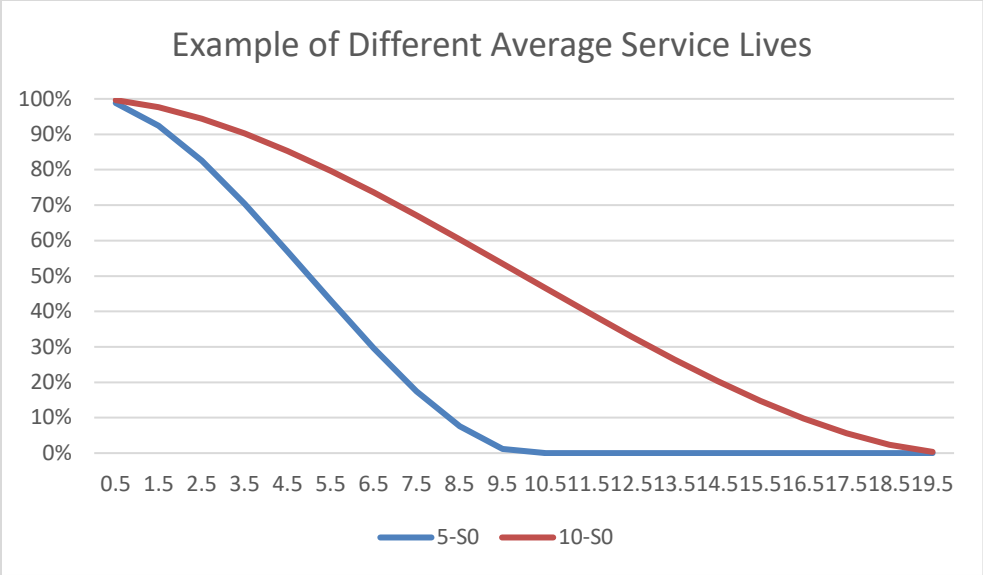
Table JSG-2 below compares curves with the same shape (S0) but different average service lives (5 and 10 years) to illustrate different iterations with the same curve. "Percent Surviving" presents the amount of plant surviving at each age interval shown in the "Age" column. The 5-S0 life and curve sums to the five-year average service life, while the 10-S0 life and curve sums to a ten-year average service life.

Table JSG-2
Sample Survivor Curves

Age	5-S0 Curve Percent Surviving	10-S0 Curve Percent Surviving
0.5	0.99	1.00
1.5	0.92	0.98
2.5	0.83	0.94
3.5	0.70	0.90
4.5	0.57	0.85
5.5	0.43	0.80
6.5	0.30	0.74
7.5	0.17	0.67
8.5	0.08	0.60
9.5	0.01	0.53
10.5		0.47
11.5		0.40
12.5		0.33
13.5		0.26
14.5		0.20
15.5		0.15
16.5		0.10
17.5		0.06
18.5		0.02
19.5		0.00
Total	**5.00**	**10.00**

These are called "curves" because, when plotted on charts with the x-axis representing "age" and the y-axis representing "percent surviving," they appear as shown below in Graph JSG-3:

Graph JSG-3



Q. HOW ARE IOWA CURVES USED IN SERVICE LIFE ANALYSIS?

A. Iowa curves enable the calculation of an average remaining life. Remaining life calculations take the current age of each vintage within an account and then use the retirement rate projected by the appropriate Iowa curve to project the remaining life of each of these vintages of plant. Ultimately, depreciation accruals for plant investment are calculated from remaining lives, so it is important to select the correct average service life and the correct Iowa curve.

Q. IS IT NECESSARY TO FIT ALL OF THE AVAILABLE DATA POINTS TAKEN FROM THE OBSERVED LIFE TABLE?

A. No. In some cases, it is appropriate to disregard some or even many of the oldest aged data. This is because actuarial data the Company keeps is often tied to long-lived assets that are such a small percentage of the total plant as to not be statistically significant. The oldest aged data may also present accounting anomalies, such as retirements that were never recorded. Disregarding oldest aged assets is called a "T-cut." While there is no hard

and fast rule for where a T-cut is required, it is generally appropriate to make a T-cut where the remaining retirement data diverges materially from the established pattern of retirements seen to that point.

The decision to make a T-cut, and at what point in the data set to make the cut, is one of the most important yet most subjective elements to an actuarial analysis. In most cases, making a larger T-cut (that is, one that results in fitting the curve to less of the actuarial data) will result in a shorter estimated average service life because the data eliminated is for the longest-lived assets in the set of data. Therefore, as explained above, a larger T-cut and the resulting shorter estimated average service life will tend to increase customer rates.

Additionally, an inconclusive analysis may occur if a larger T-cut eliminates data points from an observed life table with a limited data set (that is, an account that has a short history of plant exposed to retirement). For most Iowa curve types, the most significant difference between individual curves is seen in the portion of an Iowa curve between 85% surviving and 15% surviving. Except for O curves, Iowa curves follow a parabolic distribution of retirements. That is, Iowa curves tend to have few retirements at the beginnings and ends of their lives. The portion of the curve between 85% and 15% of surviving plant is the most indicative of the appropriate curve shape because that portion of the curve is when the bulk of retirements in a given account happen, and where variation in the pattern of retirements tends to occur. If a T-cut eliminates a portion of the observed life table survivor data between 85% surviving and 15% surviving, the matching of that data to an Iowa curve will be more likely to produce ambiguous and misleading results. The full

set of aged data should be generally used in the service life analysis unless specific circumstances warrant exclusion of the data.

V. COMPARISON OF THE EQUAL LIFE GROUP ("ELG") PROCEDURE AND AVERAGE SERVICE LIFE ("ASL") PROCEDURE

Q. WHAT ARE 'GROUP' PROCEDURES AS PERTAINING TO THE CALCULATION OF REMAINING LIVES?

A. Remaining life grouping procedures are the methods by which subsets of plant with similar life characteristics are bundled together for the purpose of determining the recovery period over which the remaining plant investment should be recovered. Different remaining life grouping procedures arrive at different recovery periods at any given point in time. The two principle grouping procedures used throughout the industry are the Average Service Life procedure (ASL) procedure and the Equal Life Group (ELG) procedure.

Q. WHAT GROUPING PROCEDURE IS MR. WIEDMAYER PROPOSING?

A. Mr. Wiedmayer is proposing to use the ASL procedure for vintages prior to 1982 and the ELG procedure for vintages after 1982.[11]

Q. WHAT IS THE DIFFERENCE BETWEEN THE ELG PROCEDURE AND ASL PROCEDURE FOR CALCULATING REMAINING LIVES?

A. The principal difference between the two procedures is that the ASL procedure assumes that all units within a particular group, typically a vintage, will share an average life.[12] The distribution of retirements is then determined using a weighting procedure across all of the

[11] Depreciation Study (FTY) page I-2.
[12] A 'vintage' refers to all of the plant placed into service in a given year.

vintages. The ELG (Equal Life Group) procedure incorporates the Iowa curve distribution of retirements within each vintage. This allows the projected shortest-lived assets within each vintage to retire simultaneously across all vintages.

Q. WHAT IS THE EFFECT OF USING ASL VS. ELG REMAINING LIFE PROCEDURES?

A. The direct effect of using ELG as opposed to ASL is that ELG depreciation rates are always going to be higher earlier on in the life cycle of a particular group of plant, and lower later in the life cycle of that plant. The following table has been excerpted from NARUC's *Depreciation Practices*, page 178:

EFFECT OF DIFFERENT PROCEDURES ON DEPRECIATION RATES AND ACCRUALS

Activity Year	*ELG*		*VG*	
	Depreciation		*Depreciation*	
	Rate	*Accruals*	*Rate*	*Accruals*
1987	*45.7%*	*$22,850*	*33.3%*	*$16,650*
1988	*33.4*	*40,040*	*25.9*	*31,080*
1989	*27.1*	*54,280*	*21.9*	*43,730*
1990	*21.1*	*35,940*	*21.4*	*36,360*
1991	*18.0*	*25,170*	*20.7*	*28,990*
1992	*15.8*	*17,350*	*19.7*	*21,620*

Note that "VG" in the table refers to "Vintage Group," which means that remaining life groups are calculated by vintage, which is the same as "Average Service Life." The table above illustrates that variation in accruals over just a short period of activity years, the

degree to which depreciation rates will be higher in earlier years and lower in later years. This variation will be greater for longer average service life plant, and the more newer plant investment is made.

Over the life of any given unit of plant, the net effect of the difference between the two procedures is zero. Both procedures recover the full amount of the investment over the service life of the investment. However, *de facto*, the use of ELG is a form of accelerated depreciation. The ELG method potentially better reflects the actual retirement patterns of a group of assets with different vintages at specific point in time, but the ELG method requires constant updating to remain accurate.

Q. WHAT ARE THE ADVANTAGES AND DISADVANTAGES OF THE TWO PROCEDURES?

A. The first and arguably most significant disadvantage of the ELG procedure is the need to frequently update the remaining life calculations. Because ELG shifts a greater portion of the depreciation expense toward the beginning of the life of particular unit of plant, depreciation expense fluctuates substantially over the life of the plant.[13] In order to ensure that the depreciation expense is accurate from year to year, remaining life calculations must be updated regularly, and companies must be obliged to submit regular depreciation studies.

The reason it is necessary to closely monitor and update depreciation rates using ELG is that if a company's remaining lives are not updated for a few years, then the

[13] National Association of Regulatory Utility Commissions *Public Utility Depreciation Practices*, pg. 63, "ELG may be expected to produce greater fluctuations in depreciation expense from year to year than the broad group procedure."

"accelerated" depreciation rates may not be accurately accounted for at the time of the utility's next rate increase request. This results in ratepayers paying those accelerated depreciation rates or for return on an understated depreciation reserve when new rates are set, when ratepayers have already paid depreciation expense during a period when depreciation rates are higher under the ELG procedure.

It is also important to consider that utility plant grows significantly each year. Because of inflation and ever-growing infrastructure needs, a very substantial portion of any given utility's plant is perpetually stuck in the "accelerated" portion of the recovery curve created by the use of ELG rates. The net effect of these factors is that the ELG remaining life procedure results in ratepayers paying more in depreciation expense in perpetuity, provided the utility's plant continues to grow consistently.

In contrast, ASL rates do not attempt to as closely mimic the actual retirement rate of individual vintages, but in doing so, this creates a smoother recovery of costs which may, in the end, more closely map to the retirement rate of the utility's plant overall. Because the remaining life remains more constant over the life of each unit, there is no need to perform annual updates to the company's remaining lives, and utilities can wait intervals of five years or more between performing depreciation studies, which reduces costs to ratepayers over time.

Q. WHAT IS THE ANNUAL IMPACT OF USING THE ELG GROUPING PROCEDURE AS OPPOSED TO THE ASL PROCEDURE?

A. I estimate that the difference in annual expense between using the ASL grouping procedure for all vintages versus using the ELG method is approximately $19.5 million. That impact will remain as long as UGI's gas plant continues to grow.

Q. WHAT DO YOU RECOMMEND REGARDING UGI'S REMAINING LIFE PROCEDURES?

A. I recommend UGI use the ASL procedure for calculating remaining lives. The ASL procedure better fits the actual ongoing investment and retirement patterns of utility plant overall, and it requires significantly less administrative upkeep by utilities and less oversight by the Commission. Mr. Wiedmeyer provided the end of period balances for each account in response to OCA 12-7 and I have used those balances to recalculate the remaining lives using the ASL procedure.

VI. ADJUSTMENTS TO SERVICE LIFE PARAMETERS FOR DISTRIBUTION

Q. PLEASE DISCUSS YOUR APPROACH TO ANALYZING MR. WIEDMEYER'S SERVICE LIFE PROPOSALS.

A. In general, I begin the analysis of a given account by first reviewing the OLT to see the distribution of exposures over time. This is primarily to check for any irregularities in the exposure data. Generally speaking, it is best to give equal weight to different ages, regardless of exposure amount. With that said, in extreme cases, magnitude of exposures may inform the subjective weight given to different periods of exposures.

Next, I review the mathematical curve-fitting routines Mr. Wiedmeyer provided in an attachment to the response to OCA data request 12-19. Taking into consideration the range of fit utilized and the way that data selection impacts the results, I then identify what the best mathematical fit to the historical retirement data is. Then, taking into consideration my experience and informed judgement to apply numerous factors, including, but not limited to, the specifics of the historical data, the type of plant in question, and the maturity

of the retirement data, I determine whether the mathematical best fit life and curve are within the range of reasonable expectations. Based on this curve-fitting analysis, I identified the best-fitting life and curve that is appropriate to the type of plant in question. This process of identifying the best-fitting curve shape to the data available is the beginning of the life-curve selection process.

Once a best-fitting curve to the data has been identified, I review the full range of information provided by Mr. Wiedmeyer pertaining to future expectations of the service life for the account being reviewed. This includes notes from Mr. Wiedmeyer on management interviews and site visits, company-provided information on future plans and projects, reasonably anticipated upcoming technological changes in the type of plant in question, and the experience of other utilities in the region and industry at large. To that end, I have reviewed UGI's responses to data requests aimed at gathering information about Mr. Wiedmeyer's life and net salvage proposals. Finally, I reviewed Part III of UGI Gas Exhibit C (Future), labeled "Service Life Considerations," in which Mr. Wiedmeyer states:

> The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during the field trips and other conversations with management; and the survivor curve estimates from previous studies of this company and other gas companies.

Mr. Wiedmeyer discusses the rationale for his selection of average service lives for a small subsection of the major plant accounts, including 380.00 – Services, 376.1 – Mains, Primarily Steel, 376.2 – Mains, Cast Iron, and 390.00 – Structures and Improvements. Mr. Wiedmayer's notes on these accounts have been incorporated into my judgment, with commentary provided for each account I am proposing to adjust.

Q. COULD YOU PLEASE DISCUSS, IN DETAIL, EACH SERVICE LIFE ADJUSTMENT YOU ARE PROPOSING?

A. Yes, the discussion following discussion explains my analysis of each account for which I am proposing to adjust the average service life. In my discussion of each account, I make extensive reference to Part VI – Service Life Statistics of Mr. Wiedmayer's future test year study. This contains Mr. Wiedmayer's OLTs for each account, as well as graphs that he has provided showing his selected.

Account 375 – Structures and Improvements

Wiedmayer Proposed life and curve; 50-S0.5

OCA Adjusted life and curve:70-O1

Discussion: Mr. Wiedmayer has proposed a 50-S0.5 life and curve for this account. Mr. Wiedmayer's proposed life and curve are a reasonable fit to the historical data through Age 45.5, where Mr Wiedmayer has elected to truncate the data in the displayed graph. However, there is very significant retirement data for this account to about Age 72.5, and the oldest retirement in the account occurs at Age 122.5. It is not clear whether Mr. Wiedmayer considered this segment of the historical data, but the data at these older ages is consistent with a considerably longer life than the 50-S0.5 curve that Mr. Wiedmayer has proposed. For instance, at Age 72.5, Mr. Wiedmayer's selected 50-S0.5 life and curve predict that only 17% of the plant will remain surviving by that age. However, without the need for extrapolation, the historical data predicts that 50% of plant will continue to survive. As a symmetrical curve, Mr. Wiedmayer's selection would predict that all plant will retire by age 100. However, what we see in the data is that by age 100 only 44.7% of plant is predicted to have retired. The best-fitting life and curve of the curves shapes

typically used in the industry is an 80-O1 curve. This is not an unreasonable curve shape for this type of plant, however, I think that an 80-year average service life is longer than I would expect for this type of plant in the future. In consideration of these factors, I am proposing a 70-O1 to conform to the best fit to the historical data, but using an average service life that is moderated slightly from the 80-year life that is the best fit.

Account 376.1 – Mains, Primarily Steel

Wiedmayer Proposed life and curve; 75 – R2.5

OCA Adjusted life and curve: 79-R2

Discussion: Mr. Wiedmayer has proposed a 75-R2.5 life and curve for this account. This curve is a reasonable fit to the company's historical data through Age 80.5, which is where Mr. Wiedmayer's graph cuts off the historical data. However, UGI's retirement data continues until the final retirement at Age 148.5, and the 75-R2.5 life and curve is a less good fit. In fact, the best fit to the full range of data is a 79-R2 life and curve, which is slightly longer, and a slightly wider distribution of retirements. This fits better both to the later period which Mr. Wiedmayer evidently did not include in his analysis, as well as to the earlier period, in which plant in this account experienced somewhat higher retirements than anticipated by the R2.5 curve shape. For these reasons, I am proposing a 79-R2 life and curve for this account.

Account 378 – Measuring and Regulating Equipment

Wiedmayer Proposed life and curve; 48-S0

OCA Adjusted life and curve:53-R0.5

Discussion Mr. Wiedmayer has proposed 48-S0 life and curve for this account. This life and curve combination are really not a particularly good fit to the available data at any segment of ages. Mr. Wiedmayer's graph cuts off at approximately age 54.5 for this account, but the retirement data continues on through age, 91.5 where the oldest retirement was recorded. The best-fitting life and curve for this account are a 60-L0.5 life and curve, but I do not believe that the L-shaped family of curves are a good fit to this type of plant, which certainly will begin to fail as it gets older. An L-shaped curve is really appropriate for types of plant that aren't subject to extensive mechanical use and don't tend to degrade in the same way. From my experience, I think an R-shaped curve makes the most sense for plant in this account. The best-fitting R-shaped curve is an R0.5 curve with a 53-year average service life. This curve is a better fit to the full range of data than Mr. Wiedmayer's proposed S0 curve. For these reasons, I am proposing a 53-R0.5 life and curve.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

JAMES SHAY GARREN

Senior Manager

CONTACT

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Lakewood, CO 80228
jgarren@newgenstrategies.net
www.newgenstrategies.net

EDUCATION

Bachelor of Arts in Literature and Philosophy, Marlboro College

Certified Depreciation Professional, Society of Depreciation Professionals

KEY EXPERTISE

Depreciation Studies and Analysis

Expert Witness Testimony and Regulatory Filings

Rate Case Support and Strategy

Revenue Requirement and Cost-of-Service Analysis

Rate Design and Cost Allocation

SOFTWARE EXPERIENCE

Microsoft Suite: Excel, Word

Adobe: Acrobat

Snavely King: SCIAS Depreciation Analysis Software

Mr. James Garren joined NewGen as a Senior Manager in October 2025. He provides expert witness testimony with a specialized focus on depreciation. He supports clients and project teams through both quantitative and qualitative analysis, the preparation of client presentations, and case management. While his primary expertise lies in depreciation studies, Mr. Garren has also prepared exhibits related to revenue requirements, cost allocation, rate design, and rate of return in regulatory proceedings. In addition, he has assisted in the preparation of valuation studies for municipal water utilities.

Mr. Garren is a member of, and has been made a Certified Depreciation Professional, by the Society of Depreciation Professionals. In addition, Mr. Garren has attended the National Association of Regulated Utility Commissioners' Rate School.

RELEVANT EXPERIENCE

Core Competencies Overview

Mr. Garren has extensive experience providing expert witness testimony and analytical support in regulatory proceedings, with a primary focus on depreciation and cost recovery mechanisms. His work includes performing independent depreciation studies, reviewing and analyzing filings, drafting data requests, and developing settlement positions through the adjustment of depreciation parameters.

He has prepared direct and rebuttal testimony, assisted in cross-examination preparation, and provided live testimony before regulatory commissions. Mr. Garren's experience also encompasses supporting clients through all stages of rate case proceedings, including discovery, testimony preparation, settlement negotiations, and the development of briefs and exhibits.

In addition to his depreciation expertise, Mr. Garren has contributed to analyses involving revenue requirements, cost allocation, rate design, and rate of return. He has also participated in valuation studies for municipal water utilities, combining both quantitative and qualitative approaches to deliver comprehensive analytical support.

JAMES SHAY GARREN

Senior Manager

Regulatory Experience

- Federal Energy Regulatory Commission
- Arizona Corporation Commission
- Barbados Fair Trade Commission
- Colorado Public Service
- Delaware Public Service Commission
- Georgia Public Service Commission
- Hawai'i Public Utilities Commission
- Kansas Corporation Commission
- Maryland Public Service Commission
- New Jersey Board of Public Utilities
- North Dakota Public Service Commission
- Pennsylvania Public Utilities Commission
- South Dakota Public Utilities Commission
- Utah Public Service Commission
- West Virginia Public Service Commission

Expert Testimony and Consulting in Rate Proceedings

- Atlantic City Electric Company – Docket No. ER22-2200 (Depreciation)
- Delmarva Power Company – Docket No. ER22-2201 (Depreciation)
- System Energy Resources – Docket No. ER22-736-000 (Depreciation)
- Potomac Electric Power Company – Docket No. ER21-83 (Depreciation)
- Baltimore Gas and Electric Company – Docket No. ER20-1929 (Depreciation)
- Jersey Central Power & Light Company – Docket No. ER20-227-000 (Depreciation)
- Pacific Gas and Electric Company – Docket No. ER17-2154-000 (Depreciation)

State Commission Utility Cases

Arizona Corporation Commission:

- Tucson Electric Power Company – AZ KCC Docket No, E-01933A-19-0028

Barbados Fair Trade Commission:

- Barbados Light and Power Company – Docket No. FTC-01/2021 BL&P-RRA-20211004

Colorado Public Utilities Commission (On Behalf of Wholesale Customer Clients):

- Public Service Company of Colorado – Proceeding No. 16A-0231E

Delaware Public Service Commission (On Behalf of Wholesale Customer Clients):

- Suez Water Delaware Inc. – DE Docket No. 19-0615

Hawai'i Public Utilities Commission:

- Hawai'i Electric, Hawai'i Electric Light, and Maui Electric – Docket No. 2016-0431

Kansas Corporation Commission:

- Kansas Gas Service – KS KCC Docket No. 18-KGSG-560-RTS
- Empire District Electric Co. – KS KCC Docket No. 19-EPDE-223-RTS

Maryland Public Service Commission:

- Delmarva Power and Light Company – MD Case Nos. 9670, 9424

- Columbia Gas Company – MD Case Nos. 9664, 9480, 9447
- Potomac Edison Company – Maryland Case No. 9490
- Pepco Electric Company – MD Case No. 9385, 9702
- Baltimore Gas and Electric Company – MD Case No. 9355, 9692

New Jersey Board of Public Utilities:

- Public Service Gas and Electric Company – NJ BPU Docket Nos. ER23120924 and GR23120925
- New Jersey American Water Company – NJ BPU Docket Nos. WR24010057
- New Jersey Natural Gas Company – NJ BPU Docket No. GR24010071
- Aqua New Jersey – NJ BPU Docket No. WR24010057
- Elizabethtown Gas Company – NJ BPU Docket No. GR24020158
- Rockland Electric Company – NJ BPU Docket Nos. ER21050823, ER19050552, ER13111135
- New Jersey Natural Gas – NJ BPU Docket No. GR21030679
- Suez Water New Jersey – NJ BPU Docket Nos. WR20110729, WR18050593
- South Jersey Gas Company – NJ BPU Docket No. GR20030243
- Jersey Central Power & Light Company – NJ BPU Docket No. ER 20020146
- Elizabethtown Gas Company – NJ BPU Docket Nos GR19040486, GR16090826
- Public Service Electric and Gas Company – NJ BPU Docket No. ER18010029 & GR18010030
- New Jersey American Water – NJ BPU Docket No WR17090985

North Dakota Public Service Commission:

- Northern States Power – ND OSC Case No. PU-20-441

Pennsylvania Public Utilities Commission:

- UGI Utilities Inc, Electric and Gas Divisions – PA PUC Docket Nos. R-2017-2640058, R-2016-2580030, 2015-2518439
- First Energy Companies – PA PUC Docket Nos. R-2016-2537349, 2537352, 2537355, 2537459

South Dakota Public Utilities Commission:

- Montana Dakota Utilities – SD PUC Docket Nos. EL23-020 and NG23-025
- Northwestern Energy – SD PUC Docket No. EL23-016

Utah Public Service Commission:

- Rocky Mountain Power – UT PSC Docket No. 18-035-036

West Virginia Public Service Commission:

- Mountaineer Gas – Case No. 15-0048-G-D

UGI UTILITIES, INC. - GAS DIVISION

OCA CALCULATED DEPRECIATION DEPRECIATION RATES AND EXPENSES
BASED ON UGI GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT	COMPOSITI REMAININC LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GAS PLANT									
PRODUCTION PLANT									
305	MANUFACTURED GAS PLANT SITE REMEDIATION			0	0	0	-	0	0.0
329	OTHER STRUCTURES			0	0	0	-	0	0.0
332	FIELD LINES			0	0	0	-	0	0.0
335	DRILLING AND CLEANING EQUIPMENT			0	0	0	-	0	0.0
TOTAL PRODUCTION PLANT				**0**	**0**	**0**	**-**	**0**	**0.0**
TRANSMISSION PLANT									
36520	RIGHTS-OF-WAY		70 - R4	868,160	583,277	284,883	1.32%	11,466	24.8
36600	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	156,987	5,229	0.49%	802	6.5
36700	MAINS		75 - R2.5	39,468,181	23,526,057	15,942,124	0.98%	386,460	41.3
36900	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2.5	6,172,834	4,347,592	1,825,242	1.37%	84,414	21.6
37000	COMMUNICATION EQUIPMENT		23 - R0.5	3,505,204	2,549,221	955,983	2.08%	72,969	13.1
37100	OTHER EQUIPMENT		35 - R2.5	140,637	133,995	6,642	0.76%	1,075	6.2
37110	TESTING EQUIPMENT		20 - R3	210,011	172,428	37,583	3.90%	8,194	4.6
TOTAL TRANSMISSION PLANT				**50,527,243**	**31,469,557**	**19,057,686**	1.12%	**565,379**	**33.7**
DISTRIBUTION PLANT									
37420	RIGHTS-OF-WAY		75 - R3	3,374,004	1,551,251	1,822,753	1.16%	39,166	46.5
37500	STRUCTURES AND IMPROVEMENTS		80 - O1	7,923,019	3,693,851	4,229,168	0.96%	75,698	55.9
37610	MAINS - PRIMARILY STEEL		75 - R2.5	787,125,750	211,746,999	575,378,751	1.19%	9,332,960	61.7
37620	MAINS - CAST IRON	09-2027	65 - R1	664,766	664,766	0	0.00%	0	17.6
37630	MAINS - PLASTIC		68 - R3	2,166,671,780	390,033,008	1,776,638,772	1.44%	31,147,466	57.0
37650	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	305,201	261,046	44,155	1.40%	4,260	10.4
37670.	REG AFUDC		40 - SQ	1,322,088	300,224	1,021,864	2.23%	29,534	34.6
37800	MEASURING AND REGULATING STATION EQUIPMENT - GENE		48 - S0	191,451,499	46,205,293	145,246,206	1.62%	3,096,187	46.9
37900	MEASURING AND REGULATING STATION EQUIPMENT - CITY (		45 - R1.5	81,779,825	16,033,091	65,746,734	2.07%	1,692,762	38.8
38000	SERVICES		45 - R2	1,799,933,111	485,016,289	1,314,916,822	2.12%	38,161,905	34.5
38100	METERS		36 - R2	160,820,610	67,493,856	93,326,754	2.39%	3,848,321	24.3
38110	METERS - ERTS		17 - S3	44,949,985	19,347,248	25,602,737	6.42%	2,887,205	8.9
38200	METER INSTALLATIONS		45 - R2	147,330,759	50,079,255	97,251,504	1.99%	2,930,506	33.2
38300	HOUSE REGULATORS		45 - R2	10,274,123	5,133,343	5,140,780	2.28%	233,901	22.0
38400	HOUSE REGULATOR INSTALLATIONS		45 - R2	17,829,357	9,800,803	8,028,554	1.69%	300,816	26.7
38500	INDUSTRIAL MEASURING AND REGULATING STATION EQUIP!		45 - R2	41,443,487	21,130,913	20,312,574	1.77%	733,601	27.7
38600	OTHER PROPERTY ON CUSTOMERS PREMISES		45 - R2	68,824	42,958	25,866	1.93%	1,328	19.5
38610	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R1.5	1,180,774	632,918	547,856	1.91%	22,578	24.3
38620	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,705	0	0.00%	0	1.7
38700	OTHER EQUIPMENT		40 - R2.5	5,308,206	3,316,734	1,991,472	1.78%	94,407	21.1
38710	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,485,147	5,517	3.52%	52,440	0.1
TOTAL DISTRIBUTION PLANT				**5,471,272,537**	**1,333,993,698**	**4,137,278,839**	**1.73%**	**94,685,040**	**43.7**
GENERAL PLANT									
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS*	168,008,808	55,336,908	112,671,900	3.92%	6,589,000	*17.1*
390.3	CNG STATIONS		15 - S3	7,022,614	251,058	6,771,556	7.15%	501,969	13.5
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,843,693	2,231,975	3,611,718	5.62%	328,671	11.0
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	211,671	89,606	122,065	11.21%	23,727	5.1

UGI UTILITIES, INC. - GAS DIVISION

OCA CALCULATED DEPRECIATION DEPRECIATION RATES AND EXPENSES
BASED ON UGI GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT	COMPOSITI REMAININC LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GAS PLANT									
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMEN		5 - SQ	14,016,581	7,096,550	6,920,031	20.83%	2,919,208	2.4
391.41	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS -		10 - SQ	5,446,944	2,343,072	3,103,872	8.95%	487,469	6.4
391.42	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS -		15 - SQ	44,342,195	10,694,286	33,647,909	6.60%	2,925,010	11.5
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	4,647,964	3,148,010	1,499,954	8.49%	394,725	3.8
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARG		10 - L2.5	50,841,189	21,105,714	29,735,475	10.08%	5,126,806	5.8
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILI		12 - L3	7,595,119	3,663,559	3,931,560	7.96%	604,855	6.5
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP		12 - L3	11,013,953	4,673,510	6,340,443	7.89%	868,554	7.3
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	2,932,322	1,338,963	1,593,359	6.17%	181,064	8.8
393	STORES EQUIPMENT		20 - SQ	15,838	7,849	7,989	4.99%	791	10.1
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	45,410,964	17,652,042	27,758,922	5.14%	2,333,105	11.9
395	LABORATORY EQUIPMENT		20 - SQ	437,779	200,930	236,849	5.13%	22,439	10.6
396	POWER OPERATED EQUIPMENT		16 - L2	13,798,162	6,098,760	7,699,402	6.41%	884,989	8.7
397	COMMUNICATION EQUIPMENT		10 - SQ	3,095,450	1,216,151	1,879,299	10.48%	324,268	5.8
398	MISCELLANEOUS EQUIPMENT		15 - SQ	1,936,970	1,208,168	728,802	3.18%	61,603	11.8
399	OTHER TANGIBLE PROPERTY			0	0	0	0.00%	0	0.0
TOTAL GENERAL PLANT				**386,618,216**	**138,357,111**	**248,261,105**	**6.36%**	**24,578,252**	**10.1**
TOTAL DEPRECIABLE GAS PLANT				**5,908,417,996**	**1,503,820,366**	**4,404,597,630**	**2.03%**	**119,828,671**	**36.8**
NONDEPRECIABLE PLANT									
301	ORGANIZATION			166,478					
302	FRANCHISES AND CONSENTS			193,597					
303	MISCELLANEOUS INTANGIBLE PLANT			289,868					
365.1	LAND			47,323					
374.1	LAND AND LAND RIGHTS - LAND			803,858					
374.2	LAND AND LAND RIGHTS - LAND RIGHTS			7,459,999					
389.1	LAND AND LAND RIGHTS - LAND			7,936,471					
389.2	LAND AND LAND RIGHTS - LAND RIGHTS			1,313					
TOTAL NONDEPRECIABLE PLANT				**16,898,907**					
TOTAL GAS PLANT				**5,925,316,903**					
OTHER UTILITY PLANT									

UGI UTILITIES, INC. - GAS DIVISION

OCA CALCULATED DEPRECIATION DEPRECIATION RATES AND EXPENSES
BASED ON UGI GAS PLANT AS OF SEPTEMBER 30, 2026

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE		AMOUNT	COMPOSITI REMAININ LIFE
(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)
GAS PLANT										
COMMON PLANT										
301	ORGANIZATION (NONDEPRECIABLE)			138,964						
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108						
390.1	STRUCTURES AND IMPROVEMENTS									
	UGI HEADQUARTERS BUILDING - DENVER	01-2069	70 - R1	35,116,171	6,755,017	28,361,154	2.55		895,246	31.7
	READING DATA CENTER	09-2073	70 - R1	20,414,469	1,880,978	18,533,491	2.84		580,484	31.9
	KNITTING MILLS OFFICE	06-2050	70 - R1	1,382,240	261,435	1,120,805	3.94		54,514	20.6
	TOTAL ACCOUNT 390.1			*56,912,880*	*8,897,430*	*48,015,450*	*2.69*		*1,530,244*	*31.4*
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,926,544	1,481,740	3,444,804	5.12		252,410	13.6
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	0	0	0	20.00	**	0	
TOTAL COMMON PLANT				**68,925,496**	**10,379,170**	**51,460,254**	**2.88**		**1,782,654**	**28.9**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 89.11%				**61,419,509**	**9,248,878**	**45,856,232**			**1,588,523**	
INFORMATION SERVICES (IS)										
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	17,877,324	9,593,313	8,284,011	19.49		3,483,451	2.4
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE									
	SUCCESS FACTORS	09-2024	SQUARE	2,803,866	2,803,866	0	-		0	0.0
	UNITE ERP	09-2034	SQUARE	10,695,816	4,583,616	6,112,200	7.14		764,025	8.0
	TOTAL ACCOUNT 391.2			*13,499,682*	*7,387,482*	*6,112,200*	*5.66*		*764,025*	*8.0*
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS -		10 - SQ	98,427,853	28,933,224	69,494,629	9.89		9,735,400	7.1
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS -		15 - SQ	134,033,083	73,969,743	60,063,340	6.82		9,134,993	6.6
TOTAL INFORMATION SERVICES				**263,837,942**	**119,883,762**	**143,954,180**	**8.76**		**23,117,869**	**6.2**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 84.82%				**223,787,342**	**101,685,407**	**122,101,935**			**19,608,576**	
EMPIRE YARD BUILDING										
390.1	STRUCTURES AND IMPROVEMENTS			12,568,452	8,904,887	3,663,565	1.50		188,254	19.5
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%				**1,642,697**	**1,163,869**	**478,828**			**24,605**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO GAS DIVISION				**283,564,155**	**109,770,416**	**167,479,340**			**21,172,495**	
TOTAL PLANT IN SERVICE				**6,208,881,057**	**1,613,590,782**	**4,572,076,969**			**141,001,166**	
AMORTIZATION OF NEGATIVE NET SALVAGE									**8,697,564**	
GRAND TOTAL				**6,208,881,057**	**1,613,590,782**	**4,572,076,969**			**149,698,730**	

* SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
** RATE TO APPLY TO FUTURE PLANT IN-SERVICE

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **36520**
Plant Account **RIGHTS-OF-WAY**

Survivor Curve R4
Average Service Life 70
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0100	$ -	69.30
2025	$ -	1.5	2	100.00%	$ -	0.0200	$ -	68.60
2024	$ 114	2.5	4	100.00%	$ 114	0.0400	$ 5	67.20
2023	$ -	3.5	5	100.00%	$ -	0.0499	$ -	66.51
2022	$ -	4.5	6	100.00%	$ -	0.0599	$ -	65.81
2021	$ -	5.5	8	100.00%	$ -	0.0799	$ -	64.41
2020	$ -	6.5	9	100.00%	$ -	0.0899	$ -	63.71
2019	$ -	7.5	11	100.00%	$ -	0.1098	$ -	62.31
2018	$ -	8.5	12	100.00%	$ -	0.1198	$ -	61.61
2017	$ -	9.5	14	100.00%	$ -	0.1397	$ -	60.22
2016	$ -	10.5	15	100.00%	$ -	0.1496	$ -	59.53
2015	$ -	11.5	16	100.00%	$ -	0.1596	$ -	58.83
2014	$ -	12.5	18	100.00%	$ -	0.1795	$ -	57.44
2013	$ -	13.5	19	100.00%	$ -	0.1894	$ -	56.74
2012	$ -	14.5	21	100.00%	$ -	0.2092	$ -	55.36
2011	$ -	15.5	22	100.00%	$ -	0.2191	$ -	54.66
2010	$ -	16.5	24	100.00%	$ -	0.2389	$ -	53.28
2009	$ -	17.5	25	100.00%	$ -	0.2488	$ -	52.58
2008	$ -	18.5	26	100.00%	$ -	0.2586	$ -	51.90
2007	$ 10,611	19.5	28	100.00%	$ 10,611	0.2783	$ 2,953	50.52
2006	$ -	20.5	29	100.00%	$ -	0.2881	$ -	49.83
2005	$ -	21.5	31	100.00%	$ -	0.3077	$ -	48.46
2004	$ 374	22.5	32	100.00%	$ 374	0.3174	$ 119	47.78
2003	$ 1,307	23.5	34	100.00%	$ 1,307	0.3369	$ 440	46.42
2002	$ 551	24.5	35	100.00%	$ 551	0.3466	$ 191	45.74
2001	$ 2,659	25.5	36	100.00%	$ 2,659	0.3562	$ 947	45.07
2000	$ 5,089	26.5	38	100.00%	$ 5,089	0.3755	$ 1,911	43.72
1999	$ 3,898	27.5	39	100.00%	$ 3,898	0.3850	$ 1,501	43.05
1998	$ 16,024	28.5	41	100.00%	$ 16,024	0.4041	$ 6,475	41.71
1997	$ 66,170	29.5	42	100.00%	$ 66,170	0.4136	$ 27,368	41.05
1996	$ 12,902	30.5	44	100.00%	$ 12,902	0.4324	$ 5,579	39.73
1995	$ 12,674	31.5	45	100.00%	$ 12,674	0.4418	$ 5,599	39.07
1994	$ 6,890	32.5	46	100.00%	$ 6,890	0.4511	$ 3,108	38.42
1993	$ 12,460	33.5	48	100.00%	$ 12,460	0.4697	$ 5,853	37.12
1992	$ 25,031	34.5	49	100.00%	$ 25,031	0.4788	$ 11,985	36.48
1991	$ 117,309	35.5	51	100.00%	$ 117,309	0.4971	$ 58,314	35.20
1990	$ 8,000	36.5	52	100.00%	$ 8,000	0.5061	$ 4,049	34.57

1989	$	1,090	37.5	54	100.00%	$	1,090	0.5240	$	571	33.32
1988	$	11,302	38.5	55	100.00%	$	11,302	0.5329	$	6,023	32.70
1987	$	3,342	39.5	56	100.00%	$	3,342	0.5417	$	1,810	32.08
1986	$	14,112	40.5	58	100.00%	$	14,112	0.5591	$	7,890	30.86
1985	$	26,755	41.5	59	100.00%	$	26,755	0.5677	$	15,189	30.26
1984	$	15,251	42.5	61	100.00%	$	15,251	0.5848	$	8,919	29.06
1983	$	9,041	43.5	62	100.00%	$	9,041	0.5932	$	5,363	28.48
1982	$	10,051	44.5	64	100.00%	$	10,051	0.6098	$	6,129	27.31
1981	$	73,749	45.5	65	100.00%	$	73,749	0.6181	$	45,584	26.73
1980	$	4,856	46.5	66	100.00%	$	4,856	0.6262	$	3,041	26.17
1979	$	7,570	47.5	68	100.00%	$	7,570	0.6422	$	4,862	25.05
1978	$	12,918	48.5	69	100.00%	$	12,918	0.6501	$	8,398	24.49
1977	$	11,905	49.5	71	100.00%	$	11,905	0.6657	$	7,925	23.40
1976	$	7,995	50.5	72	100.00%	$	7,995	0.6734	$	5,384	22.86
1975	$	11,481	51.5	74	100.00%	$	11,481	0.6886	$	7,906	21.80
1974	$	8,346	52.5	75	100.00%	$	8,346	0.6960	$	5,809	21.28
1973	$	5,080	53.5	76	100.00%	$	5,080	0.7034	$	3,574	20.76
1972	$	11,935	54.5	78	100.00%	$	11,935	0.7180	$	8,570	19.74
1971	$	1,200	55.5	79	100.00%	$	1,200	0.7251	$	870	19.24
1970	$	18,016	56.5	81	100.00%	$	18,016	0.7392	$	13,317	18.26
1969	$	12,471	57.5	82	100.00%	$	12,471	0.7462	$	9,306	17.77
1968	$	3,797	58.5	84	100.00%	$	3,797	0.7599	$	2,885	16.81
1967	$	22,319	59.5	85	100.00%	$	22,319	0.7667	$	17,112	16.33
1966	$	36,334	60.5	86	100.00%	$	36,334	0.7733	$	28,097	15.87
1965	$	6,573	61.5	88	100.00%	$	6,573	0.7864	$	5,169	14.95
1964	$	5,365	62.5	89	100.00%	$	5,365	0.7928	$	4,254	14.50
1963	$	3,157	63.5	91	100.00%	$	3,157	0.8052	$	2,542	13.64
1962	$	3,222	64.5	92	100.00%	$	3,222	0.8112	$	2,614	13.22
1961	$	2,661	65.5	94	100.00%	$	2,661	0.8228	$	2,189	12.40
1960	$	11,197	66.5	95	100.00%	$	11,197	0.8284	$	9,276	12.01
1959	$	3,405	67.5	96	100.00%	$	3,405	0.8337	$	2,839	11.64
1958	$	3,855	68.5	98	100.00%	$	3,855	0.8440	$	3,253	10.92
1957	$	2,232	69.5	99	100.00%	$	2,232	0.8489	$	1,894	10.58
1956	$	78,472	70.5	101	100.00%	$	78,472	0.8582	$	67,344	9.93
1955	$	8,391	71.5	102	100.00%	$	8,391	0.8627	$	7,239	9.61
1954	$	14,354	72.5	104	100.00%	$	14,354	0.8710	$	12,502	9.03
1953	$	5,401	73.5	105	100.00%	$	5,401	0.8750	$	4,725	8.75
1952	$	198	74.5	106	100.00%	$	198	0.8789	$	174	8.48
1951	$	4,042	75.5	108	100.00%	$	4,042	0.8863	$	3,583	7.96
1950	$	191	76.5	109	100.00%	$	191	0.8898	$	170	7.71
1949	$	1,157	77.5	111	100.00%	$	1,157	0.8965	$	1,038	7.25
1948	$	4,636	78.5	112	100.00%	$	4,636	0.8997	$	4,171	7.02
1947	$	2,508	79.5	114	100.00%	$	2,508	0.9060	$	2,273	6.58
1946	$	3,351	80.5	115	100.00%	$	3,351	0.9090	$	3,046	6.37
1945	$	631	81.5	116	100.00%	$	631	0.9119	$	575	6.17
1944	$	422	82.5	118	100.00%	$	422	0.9177	$	387	5.76
1943	$	60	83.5	119	100.00%	$	60	0.9205	$	55	5.57
1942	$	337	84.5	121	100.00%	$	337	0.9261	$	313	5.17
1941	$	593	85.5	122	100.00%	$	593	0.9288	$	551	4.98
1940	$	6,451	86.5	124	100.00%	$	6,451	0.9342	$	6,026	4.61
1939	$	963	87.5	125	100.00%	$	963	0.9368	$	902	4.42
1938	$	375	88.5	126	100.00%	$	375	0.9394	$	353	4.24
1937	$	203	89.5	128	100.00%	$	203	0.9447	$	192	3.87
1936	$	-	90.5	129	100.00%	$	-	0.9472	$	-	3.70
1935	$	13	91.5	131	100.00%	$	13	0.9523	$	12	3.34

1934	$	813	92.5	132	100.00%	$	813	0.9548	$	776	3.16
1933	$	539	93.5	134	100.00%	$	539	0.9597	$	517	2.82
1932	$	2,641	94.5	135	100.00%	$	2,641	0.9621	$	2,540	2.65
1931	$	27,123	95.5	136	100.00%	$	27,123	0.9645	$	26,160	2.49
1930	$	2,041	96.5	138	100.00%	$	2,041	0.9692	$	1,978	2.16
1929	$	1,806	97.5	139	100.00%	$	1,806	0.9714	$	1,755	2.00
1928	$	-	98.5	141	100.00%	$	-	0.9758	$	-	1.69
1927	$	-	99.5	142	100.00%	$	-	0.9780	$	-	1.54
1926	$	6,472	100.5	144	100.00%	$	6,472	0.9821	$	6,356	1.25
1925	$	-	101.5	145	100.00%	$	-	0.9842	$	-	1.11
1924	$	-	102.5	146	100.00%	$	-	0.9861	$	-	0.97
1923	$	-	103.5	148	100.00%	$	-	0.9899	$	-	0.71
1922	$	-	104.5	149	100.00%	$	-	0.9917	$	-	0.58
1921	$	-	105.5	151	100.00%	$	-	0.9945	$	-	0.38
1920	$	-	106.5	152	100.00%	$	-	0.9950	$	-	0.35
1919	$	-	107.5	154	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	155	100.00%	$	-	1.0000	$	-	0.00
1917	$	64	109.5	156	100.00%	$	64	1.0000	$	64	0.00
1916	$	118	110.5	158	100.00%	$	118	1.0000	$	118	0.00
1915	$	224	111.5	159	100.00%	$	224	1.0000	$	224	0.00
1914	$	15	112.5	161	100.00%	$	15	1.0000	$	15	0.00
1913	$	222	113.5	162	100.00%	$	222	1.0000	$	222	0.00
1912	$	835	114.5	164	100.00%	$	835	1.0000	$	835	0.00
1911	$	-	115.5	165	100.00%	$	-	1.0000	$	-	0.00
1910	$	85	116.5	166	100.00%	$	85	1.0000	$	85	0.00
1909	$	-	117.5	168	100.00%	$	-	1.0000	$	-	0.00
1908	$	44	118.5	169	100.00%	$	44	1.0000	$	44	0.00
1907	$	-	119.5	171	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	172	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	174	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	175	100.00%	$	-	1.0000	$	-	0.00
1903	$	4,111	123.5	176	100.00%	$	4,111	1.0000	$	4,111	0.00
1902	$	3,610	124.5	178	100.00%	$	3,610	1.0000	$	3,610	0.00
1901	$	-	125.5	179	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	181	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	182	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	184	100.00%	$	-	1.0000	$	-	0.00
1897	$	-	129.5	185	100.00%	$	-	1.0000	$	-	0.00
1896	$	-	130.5	186	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	188	100.00%	$	-	1.0000	$	-	0.00
1894	$	-	132.5	189	100.00%	$	-	1.0000	$	-	0.00
1893	$	-	133.5	191	100.00%	$	-	1.0000	$	-	0.00
1892	$	-	134.5	192	100.00%	$	-	1.0000	$	-	0.00
1891	$	-	135.5	194	100.00%	$	-	1.0000	$	-	0.00
1890	$	-	136.5	195	100.00%	$	-	1.0000	$	-	0.00
1889	$	-	137.5	196	100.00%	$	-	1.0000	$	-	0.00
1888	$	-	138.5	198	100.00%	$	-	1.0000	$	-	0.00
1887	$	-	139.5	199	100.00%	$	-	1.0000	$	-	0.00
1886	$	-	140.5	201	100.00%	$	-	1.0000	$	-	0.00
1885	$	-	141.5	202	100.00%	$	-	1.0000	$	-	0.00
1884	$	-	142.5	204	100.00%	$	-	1.0000	$	-	0.00
1883	$	-	143.5	205	100.00%	$	-	1.0000	$	-	0.00
1882	$	-	144.5	206	100.00%	$	-	1.0000	$	-	0.00
Total	$	868,160				$	868,160		$	560,002	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 560,002	
Average Remaining Life		24.85
Theoretical Reserve %	64.50%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **36600**
Plant Account **STRUCTURES AND IMPROVEMENTS**

Survivor Curve R1
Average Service Life 30
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	2	100.00%	$ -	0.0148	$ -	29.56
2025	$ -	1.5	5	100.00%	$ -	0.0369	$ -	28.89
2024	$ -	2.5	8	100.00%	$ -	0.0587	$ -	28.24
2023	$ -	3.5	12	100.00%	$ -	0.0876	$ -	27.37
2022	$ -	4.5	15	100.00%	$ -	0.1090	$ -	26.73
2021	$ -	5.5	18	100.00%	$ -	0.1302	$ -	26.09
2020	$ 138	6.5	22	100.00%	$ 138	0.1583	$ 22	25.25
2019	$ 11,416	7.5	25	100.00%	$ 11,416	0.1792	$ 2,046	24.62
2018	$ -	8.5	28	100.00%	$ -	0.1999	$ -	24.00
2017	$ -	9.5	32	100.00%	$ -	0.2273	$ -	23.18
2016	$ -	10.5	35	100.00%	$ -	0.2477	$ -	22.57
2015	$ -	11.5	38	100.00%	$ -	0.2680	$ -	21.96
2014	$ -	12.5	42	100.00%	$ -	0.2947	$ -	21.16
2013	$ -	13.5	45	100.00%	$ -	0.3146	$ -	20.56
2012	$ -	14.5	48	100.00%	$ -	0.3343	$ -	19.97
2011	$ -	15.5	52	100.00%	$ -	0.3602	$ -	19.19
2010	$ -	16.5	55	100.00%	$ -	0.3794	$ -	18.62
2009	$ -	17.5	58	100.00%	$ -	0.3983	$ -	18.05
2008	$ -	18.5	62	100.00%	$ -	0.4232	$ -	17.30
2007	$ -	19.5	65	100.00%	$ -	0.4415	$ -	16.76
2006	$ -	20.5	68	100.00%	$ -	0.4595	$ -	16.22
2005	$ -	21.5	72	100.00%	$ -	0.4831	$ -	15.51
2004	$ 1,760	22.5	75	100.00%	$ 1,760	0.5004	$ 881	14.99
2003	$ -	23.5	78	100.00%	$ -	0.5174	$ -	14.48
2002	$ -	24.5	82	100.00%	$ -	0.5397	$ -	13.81
2001	$ -	25.5	85	100.00%	$ -	0.5560	$ -	13.32
2000	$ -	26.5	88	100.00%	$ -	0.5719	$ -	12.84
1999	$ -	27.5	92	100.00%	$ -	0.5928	$ -	12.22
1998	$ 1,576	28.5	95	100.00%	$ 1,576	0.6080	$ 958	11.76
1997	$ -	29.5	98	100.00%	$ -	0.6230	$ -	11.31
1996	$ 1,216	30.5	102	100.00%	$ 1,216	0.6424	$ 781	10.73
1995	$ -	31.5	105	100.00%	$ -	0.6566	$ -	10.30
1994	$ 602	32.5	108	100.00%	$ 602	0.6706	$ 404	9.88
1993	$ -	33.5	112	100.00%	$ -	0.6887	$ -	9.34
1992	$ -	34.5	115	100.00%	$ -	0.7019	$ -	8.94
1991	$ -	35.5	118	100.00%	$ -	0.7149	$ -	8.55
1990	$ -	36.5	122	100.00%	$ -	0.7318	$ -	8.05

1989	$	44,845	37.5	125	100.00%	$	44,845	0.7442	$	33,374	7.67
1988	$	31,016	38.5	128	100.00%	$	31,016	0.7563	$	23,457	7.31
1987	$	1,015	39.5	132	100.00%	$	1,015	0.7720	$	783	6.84
1986	$	241	40.5	135	100.00%	$	241	0.7835	$	189	6.50
1985	$	9,821	41.5	138	100.00%	$	9,821	0.7948	$	7,806	6.16
1984	$	369	42.5	142	100.00%	$	369	0.8094	$	299	5.72
1983	$	5,282	43.5	145	100.00%	$	5,282	0.8202	$	4,332	5.39
1982	$	-	44.5	148	100.00%	$	-	0.8307	$	-	5.08
1981	$	-	45.5	152	100.00%	$	-	0.8443	$	-	4.67
1980	$	-	46.5	155	100.00%	$	-	0.8543	$	-	4.37
1979	$	2,204	47.5	158	100.00%	$	2,204	0.8641	$	1,904	4.08
1978	$	2,207	48.5	162	100.00%	$	2,207	0.8769	$	1,936	3.69
1977	$	194	49.5	165	100.00%	$	194	0.8862	$	172	3.41
1976	$	-	50.5	168	100.00%	$	-	0.8954	$	-	3.14
1975	$	-	51.5	172	100.00%	$	-	0.9074	$	-	2.78
1974	$	4,751	52.5	175	100.00%	$	4,751	0.9163	$	4,353	2.51
1973	$	701	53.5	178	100.00%	$	701	0.9252	$	648	2.24
1972	$	-	54.5	182	100.00%	$	-	0.9372	$	-	1.88
1971	$	1,214	55.5	185	100.00%	$	1,214	0.9467	$	1,149	1.60
1970	$	40	56.5	188	100.00%	$	40	0.9567	$	38	1.30
1969	$	545	57.5	192	100.00%	$	545	0.9701	$	528	0.90
1968	$	2,151	58.5	195	100.00%	$	2,151	0.9801	$	2,109	0.60
1967	$	9,978	59.5	198	100.00%	$	9,978	0.9896	$	9,874	0.31
1966	$	2,250	60.5	202	100.00%	$	2,250	1.0000	$	2,250	0.00
1965	$	2,343	61.5	205	100.00%	$	2,343	1.0000	$	2,343	0.00
1964	$	191	62.5	208	100.00%	$	191	1.0000	$	191	0.00
1963	$	736	63.5	212	100.00%	$	736	1.0000	$	736	0.00
1962	$	2,283	64.5	215	100.00%	$	2,283	1.0000	$	2,283	0.00
1961	$	4,353	65.5	218	100.00%	$	4,353	1.0000	$	4,353	0.00
1960	$	6,541	66.5	222	100.00%	$	6,541	1.0000	$	6,541	0.00
1959	$	300	67.5	225	100.00%	$	300	1.0000	$	300	0.00
1958	$	2,058	68.5	228	100.00%	$	2,058	1.0000	$	2,058	0.00
1957	$	310	69.5	232	100.00%	$	310	1.0000	$	310	0.00
1956	$	2,296	70.5	235	100.00%	$	2,296	1.0000	$	2,296	0.00
1955	$	1,082	71.5	238	100.00%	$	1,082	1.0000	$	1,082	0.00
1954	$	399	72.5	242	100.00%	$	399	1.0000	$	399	0.00
1953	$	97	73.5	245	100.00%	$	97	1.0000	$	97	0.00
1952	$	-	74.5	248	100.00%	$	-	1.0000	$	-	0.00
1951	$	-	75.5	252	100.00%	$	-	1.0000	$	-	0.00
1950	$	-	76.5	255	100.00%	$	-	1.0000	$	-	0.00
1949	$	-	77.5	258	100.00%	$	-	1.0000	$	-	0.00
1948	$	-	78.5	262	100.00%	$	-	1.0000	$	-	0.00
1947	$	-	79.5	265	100.00%	$	-	1.0000	$	-	0.00
1946	$	195	80.5	268	100.00%	$	195	1.0000	$	195	0.00
1945	$	-	81.5	272	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	275	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	278	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	282	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	285	100.00%	$	-	1.0000	$	-	0.00
1940	$	343	86.5	288	100.00%	$	343	1.0000	$	343	0.00
1939	$	2,662	87.5	292	100.00%	$	2,662	1.0000	$	2,662	0.00
1938	$	-	88.5	295	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	298	100.00%	$	-	1.0000	$	-	0.00
1936	$	429	90.5	302	100.00%	$	429	1.0000	$	429	0.00
1935	$	-	91.5	305	100.00%	$	-	1.0000	$	-	0.00

1934	$	-	92.5	308	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	312	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	315	100.00%	$	-	1.0000	$	-	0.00
1931	$	22	95.5	318	100.00%	$	22	1.0000	$	22	0.00
1930	$	-	96.5	322	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	325	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	328	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	332	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	335	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	338	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	342	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	345	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	348	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	352	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	355	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	358	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	362	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	365	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	368	100.00%	$	-	1.0000	$	-	0.00
1915	$	44	111.5	372	100.00%	$	44	1.0000	$	44	0.00
1914	$	-	112.5	375	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	378	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	382	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	385	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	388	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	392	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	395	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	398	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	402	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	405	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	408	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	412	100.00%	$	-	0.0000	$	-	30.00
1902	$	-	124.5	415	100.00%	$	-	0.0000	$	-	30.00
1901	$	-	125.5	418	100.00%	$	-	0.0000	$	-	30.00
1900	$	-	126.5	422	100.00%	$	-	0.0000	$	-	30.00
1899	$	-	127.5	425	100.00%	$	-	0.0000	$	-	30.00
1898	$	-	128.5	428	100.00%	$	-	0.0000	$	-	30.00
1897	$	-	129.5	432	100.00%	$	-	0.0000	$	-	30.00
1896	$	-	130.5	435	100.00%	$	-	0.0000	$	-	30.00
1895	$	-	131.5	438	100.00%	$	-	0.0000	$	-	30.00
1894	$	-	132.5	442	100.00%	$	-	0.0000	$	-	30.00
1893	$	-	133.5	445	100.00%	$	-	0.0000	$	-	30.00
1892	$	-	134.5	448	100.00%	$	-	0.0000	$	-	30.00
1891	$	-	135.5	452	100.00%	$	-	0.0000	$	-	30.00
1890	$	-	136.5	455	100.00%	$	-	0.0000	$	-	30.00
1889	$	-	137.5	458	100.00%	$	-	0.0000	$	-	30.00
1888	$	-	138.5	462	100.00%	$	-	0.0000	$	-	30.00
1887	$	-	139.5	465	100.00%	$	-	0.0000	$	-	30.00
1886	$	-	140.5	468	100.00%	$	-	0.0000	$	-	30.00
1885	$	-	141.5	472	100.00%	$	-	0.0000	$	-	30.00
1884	$	-	142.5	475	100.00%	$	-	0.0000	$	-	30.00
1883	$	-	143.5	478	100.00%	$	-	0.0000	$	-	30.00
1882	$	-	144.5	482	100.00%	$	-	0.0000	$	-	30.00
Total	$	162,216				$	162,216		$	126,977	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 126,977	
Average Remaining Life		6.52
Theoretical Reserve %	78.28%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **36700**
Plant Account **MAINS**

Survivor Curve R2.5
Average Service Life 75
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0095	$ -	74.29
2025	$ 643,849	1.5	2	100.00%	$ 643,849	0.0189	$ 12,169	73.58
2024	$ 307,730	2.5	3	100.00%	$ 307,730	0.0283	$ 8,709	72.88
2023	$ -	3.5	5	100.00%	$ -	0.0471	$ -	71.47
2022	$ -	4.5	6	100.00%	$ -	0.0564	$ -	70.77
2021	$ -	5.5	7	100.00%	$ -	0.0658	$ -	70.07
2020	$ -	6.5	9	100.00%	$ -	0.0844	$ -	68.67
2019	$ -	7.5	10	100.00%	$ -	0.0936	$ -	67.98
2018	$ -	8.5	11	100.00%	$ -	0.1029	$ -	67.28
2017	$ -	9.5	13	100.00%	$ -	0.1213	$ -	65.90
2016	$ -	10.5	14	100.00%	$ -	0.1305	$ -	65.21
2015	$ -	11.5	15	100.00%	$ -	0.1396	$ -	64.53
2014	$ -	12.5	17	100.00%	$ -	0.1579	$ -	63.16
2013	$ 41,990	13.5	18	100.00%	$ 41,990	0.1669	$ 7,008	62.48
2012	$ 2,357,531	14.5	19	100.00%	$ 2,357,531	0.1760	$ 414,925	61.80
2011	$ 140,624	15.5	21	100.00%	$ 140,624	0.1940	$ 27,281	60.45
2010	$ 158,385	16.5	22	100.00%	$ 158,385	0.2029	$ 32,136	59.78
2009	$ 74,106	17.5	23	100.00%	$ 74,106	0.2119	$ 15,703	59.11
2008	$ 103,423	18.5	25	100.00%	$ 103,423	0.2296	$ 23,746	57.78
2007	$ 509,992	19.5	26	100.00%	$ 509,992	0.2385	$ 121,633	57.11
2006	$ 169,927	20.5	27	100.00%	$ 169,927	0.2473	$ 42,023	56.45
2005	$ 237,739	21.5	29	100.00%	$ 237,739	0.2648	$ 62,953	55.14
2004	$ 239,158	22.5	30	100.00%	$ 239,158	0.2735	$ 65,410	54.49
2003	$ 537,155	23.5	31	100.00%	$ 537,155	0.2821	$ 151,531	53.84
2002	$ 1,450,386	24.5	33	100.00%	$ 1,450,386	0.2994	$ 434,246	52.55
2001	$ 940,487	25.5	34	100.00%	$ 940,487	0.3079	$ 289,576	51.91
2000	$ 2,093,640	26.5	35	100.00%	$ 2,093,640	0.3164	$ 662,428	51.27
1999	$ 1,080,766	27.5	37	100.00%	$ 1,080,766	0.3334	$ 360,327	50.00
1998	$ 1,718,963	28.5	38	100.00%	$ 1,718,963	0.3418	$ 587,541	49.37
1997	$ 1,997,584	29.5	39	100.00%	$ 1,997,584	0.3502	$ 699,554	48.74
1996	$ 804,324	30.5	41	100.00%	$ 804,324	0.3668	$ 295,026	47.49
1995	$ 571,362	31.5	42	100.00%	$ 571,362	0.3750	$ 214,261	46.88
1994	$ 971,986	32.5	43	100.00%	$ 971,986	0.3832	$ 372,465	46.26
1993	$ 1,136,544	33.5	45	100.00%	$ 1,136,544	0.3995	$ 454,049	45.04
1992	$ 1,177,931	34.5	46	100.00%	$ 1,177,931	0.4076	$ 480,125	44.43
1991	$ 2,298,209	35.5	47	100.00%	$ 2,298,209	0.4156	$ 955,136	43.83
1990	$ 360,151	36.5	49	100.00%	$ 360,151	0.4316	$ 155,441	42.63

1989	$ 207,476	37.5	50	100.00%	$ 207,476	0.4395	$ 91,186	42.04
1988	$ 491,903	38.5	51	100.00%	$ 491,903	0.4473	$ 220,028	41.45
1987	$ 414,536	39.5	53	100.00%	$ 414,536	0.4629	$ 191,889	40.28
1986	$ 565,064	40.5	54	100.00%	$ 565,064	0.4706	$ 265,919	39.71
1985	$ 455,844	41.5	55	100.00%	$ 455,844	0.4783	$ 218,030	39.13
1984	$ 749,802	42.5	57	100.00%	$ 749,802	0.4935	$ 370,028	37.99
1983	$ 524,888	43.5	58	100.00%	$ 524,888	0.5010	$ 262,969	37.43
1982	$ 319,398	44.5	59	100.00%	$ 319,398	0.5084	$ 162,382	36.87
1981	$ 283,712	45.5	61	100.00%	$ 283,712	0.5232	$ 148,438	35.76
1980	$ 243,614	46.5	62	100.00%	$ 243,614	0.5306	$ 129,261	35.21
1979	$ 501,981	47.5	63	100.00%	$ 501,981	0.5378	$ 269,966	34.67
1978	$ 287,058	48.5	65	100.00%	$ 287,058	0.5522	$ 158,513	33.59
1977	$ 134,300	49.5	66	100.00%	$ 134,300	0.5593	$ 75,114	33.05
1976	$ 137,472	50.5	67	100.00%	$ 137,472	0.5663	$ 77,850	32.53
1975	$ 297,092	51.5	69	100.00%	$ 297,092	0.5803	$ 172,403	31.48
1974	$ 485,847	52.5	70	100.00%	$ 485,847	0.5871	$ 285,241	30.97
1973	$ 372,162	53.5	71	100.00%	$ 372,162	0.5940	$ 221,064	30.45
1972	$ 966,536	54.5	73	100.00%	$ 966,536	0.6074	$ 587,074	29.45
1971	$ 453,818	55.5	74	100.00%	$ 453,818	0.6140	$ 278,644	28.95
1970	$ 874,219	56.5	75	100.00%	$ 874,219	0.6206	$ 542,540	28.46
1969	$ 640,488	57.5	77	100.00%	$ 640,488	0.6336	$ 405,813	27.48
1968	$ 370,390	58.5	78	100.00%	$ 370,390	0.6399	$ 237,012	27.01
1967	$ 215,828	59.5	79	100.00%	$ 215,828	0.6463	$ 139,489	26.53
1966	$ 742,304	60.5	81	100.00%	$ 742,304	0.6587	$ 488,956	25.60
1965	$ 701,421	61.5	82	100.00%	$ 701,421	0.6648	$ 466,304	25.14
1964	$ 290,970	62.5	83	100.00%	$ 290,970	0.6708	$ 195,182	24.69
1963	$ 122,061	63.5	85	100.00%	$ 122,061	0.6826	$ 83,319	23.81
1962	$ 190,718	64.5	86	100.00%	$ 190,718	0.6884	$ 131,290	23.37
1961	$ 47,892	65.5	87	100.00%	$ 47,892	0.6941	$ 33,242	22.94
1960	$ 674,920	66.5	89	100.00%	$ 674,920	0.7053	$ 476,021	22.10
1959	$ 613,382	67.5	90	100.00%	$ 613,382	0.7108	$ 435,992	21.69
1958	$ 299,805	68.5	91	100.00%	$ 299,805	0.7162	$ 214,720	21.29
1957	$ 311,182	69.5	93	100.00%	$ 311,182	0.7268	$ 226,167	20.49
1956	$ 1,473,781	70.5	94	100.00%	$ 1,473,781	0.7319	$ 1,078,660	20.11
1955	$ 81,749	71.5	95	100.00%	$ 81,749	0.7370	$ 60,249	19.73
1954	$ 797,824	72.5	97	100.00%	$ 797,824	0.7469	$ 595,895	18.98
1953	$ 200,021	73.5	98	100.00%	$ 200,021	0.7517	$ 150,356	18.62
1952	$ 22,208	74.5	99	100.00%	$ 22,208	0.7564	$ 16,798	18.27
1951	$ 202,177	75.5	101	100.00%	$ 202,177	0.7656	$ 154,787	17.58
1950	$ 2,736	76.5	102	100.00%	$ 2,736	0.7700	$ 2,106	17.25
1949	$ 28,199	77.5	103	100.00%	$ 28,199	0.7744	$ 21,837	16.92
1948	$ 98,837	78.5	105	100.00%	$ 98,837	0.7829	$ 77,380	16.28
1947	$ 24,942	79.5	106	100.00%	$ 24,942	0.7870	$ 19,629	15.98
1946	$ 4,905	80.5	107	100.00%	$ 4,905	0.7910	$ 3,880	15.68
1945	$ 1,498	81.5	109	100.00%	$ 1,498	0.7988	$ 1,197	15.09
1944	$ 48	82.5	110	100.00%	$ 48	0.8026	$ 39	14.81
1943	$ 5,839	83.5	111	100.00%	$ 5,839	0.8063	$ 4,708	14.53
1942	$ 1,216	84.5	113	100.00%	$ 1,216	0.8134	$ 989	14.00
1941	$ 11,634	85.5	114	100.00%	$ 11,634	0.8169	$ 9,503	13.73
1940	$ 11,365	86.5	115	100.00%	$ 11,365	0.8203	$ 9,322	13.48
1939	$ 798	87.5	117	100.00%	$ 798	0.8268	$ 659	12.99
1938	$ 2,798	88.5	118	100.00%	$ 2,798	0.8300	$ 2,322	12.75
1937	$ 2,389	89.5	119	100.00%	$ 2,389	0.8331	$ 1,990	12.52
1936	$ 16,622	90.5	121	100.00%	$ 16,622	0.8391	$ 13,948	12.07
1935	$ 1,411	91.5	122	100.00%	$ 1,411	0.8421	$ 1,188	11.84

1934	$ 10,855	92.5	123	100.00%	$ 10,855	0.8449	$ 9,172	11.63
1933	$ 4,897	93.5	125	100.00%	$ 4,897	0.8505	$ 4,165	11.21
1932	$ 122,819	94.5	126	100.00%	$ 122,819	0.8532	$ 104,789	11.01
1931	$ 297	95.5	127	100.00%	$ 297	0.8559	$ 254	10.81
1930	$ 2,523	96.5	129	100.00%	$ 2,523	0.8612	$ 2,173	10.41
1929	$ 27,529	97.5	130	100.00%	$ 27,529	0.8637	$ 23,777	10.22
1928	$ 180	98.5	131	100.00%	$ 180	0.8663	$ 156	10.03
1927	$ 2,172	99.5	133	100.00%	$ 2,172	0.8712	$ 1,892	9.66
1926	$ 46,464	100.5	134	100.00%	$ 46,464	0.8737	$ 40,596	9.47
1925	$ 1,357	101.5	135	100.00%	$ 1,357	0.8761	$ 1,189	9.29
1924	$ -	102.5	137	100.00%	$ -	0.8809	$ -	8.93
1923	$ -	103.5	138	100.00%	$ -	0.8833	$ -	8.75
1922	$ 36	104.5	139	100.00%	$ 36	0.8856	$ 31	8.58
1921	$ -	105.5	141	100.00%	$ -	0.8902	$ -	8.24
1920	$ -	106.5	142	100.00%	$ -	0.8925	$ -	8.06
1919	$ -	107.5	143	100.00%	$ -	0.8948	$ -	7.89
1918	$ -	108.5	145	100.00%	$ -	0.8993	$ -	7.55
1917	$ -	109.5	146	100.00%	$ -	0.9015	$ -	7.39
1916	$ -	110.5	147	100.00%	$ -	0.9038	$ -	7.22
1915	$ 63	111.5	149	100.00%	$ 63	0.9081	$ 58	6.89
1914	$ -	112.5	150	100.00%	$ -	0.9103	$ -	6.73
1913	$ 1,738	113.5	151	100.00%	$ 1,738	0.9125	$ 1,586	6.56
1912	$ -	114.5	153	100.00%	$ -	0.9169	$ -	6.23
1911	$ -	115.5	154	100.00%	$ -	0.9190	$ -	6.08
1910	$ 749	116.5	155	100.00%	$ 749	0.9212	$ 690	5.91
1909	$ -	117.5	157	100.00%	$ -	0.9256	$ -	5.58
1908	$ -	118.5	158	100.00%	$ -	0.9279	$ -	5.41
1907	$ 8,730	119.5	159	100.00%	$ 8,730	0.9302	$ 8,121	5.24
1906	$ 2,421	120.5	161	100.00%	$ 2,421	0.9349	$ 2,263	4.88
1905	$ -	121.5	162	100.00%	$ -	0.9373	$ -	4.70
1904	$ 1,965	122.5	163	100.00%	$ 1,965	0.9398	$ 1,846	4.52
1903	$ 33,197	123.5	165	100.00%	$ 33,197	0.9450	$ 31,371	4.13
1902	$ 24,056	124.5	166	100.00%	$ 24,056	0.9477	$ 22,798	3.92
1901	$ -	125.5	167	100.00%	$ -	0.9504	$ -	3.72
1900	$ 71,114	126.5	169	100.00%	$ 71,114	0.9559	$ 67,978	3.31
1899	$ -	127.5	170	100.00%	$ -	0.9587	$ -	3.10
1898	$ -	128.5	171	100.00%	$ -	0.9614	$ -	2.90
1897	$ -	129.5	173	100.00%	$ -	0.9668	$ -	2.49
1896	$ -	130.5	174	100.00%	$ -	0.9694	$ -	2.30
1895	$ -	131.5	175	100.00%	$ -	0.9719	$ -	2.11
1894	$ -	132.5	177	100.00%	$ -	0.9772	$ -	1.71
1893	$ -	133.5	178	100.00%	$ -	0.9797	$ -	1.52
1892	$ -	134.5	179	100.00%	$ -	0.9823	$ -	1.33
1891	$ -	135.5	181	100.00%	$ -	0.9865	$ -	1.01
1890	$ -	136.5	182	100.00%	$ -	0.9893	$ -	0.80
1889	$ -	137.5	183	100.00%	$ -	0.9917	$ -	0.62
1888	$ -	138.5	185	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	186	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	187	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	189	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	190	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	191	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	193	100.00%	$ -	1.0000	$ -	0.00
Total	$ 39,468,181				$ 39,468,181		$ 17,759,795	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 17,759,795	
Average Remaining Life		41.25
Theoretical Reserve %	45.00%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **36900**
Plant Account **MEASURING AND REGULATING STATION EQUIPMENT**

Survivor Curve R2.5
Average Service Life 49
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0095	$ -	48.53
2025	$ -	1.5	3	100.00%	$ -	0.0283	$ -	47.61
2024	$ -	2.5	5	100.00%	$ -	0.0471	$ -	46.69
2023	$ -	3.5	7	100.00%	$ -	0.0658	$ -	45.78
2022	$ 23,130	4.5	9	100.00%	$ 23,130	0.0844	$ 1,952	44.86
2021	$ 1,311	5.5	11	100.00%	$ 1,311	0.1029	$ 135	43.96
2020	$ -	6.5	13	100.00%	$ -	0.1213	$ -	43.06
2019	$ -	7.5	15	100.00%	$ -	0.1396	$ -	42.16
2018	$ -	8.5	17	100.00%	$ -	0.1579	$ -	41.26
2017	$ -	9.5	19	100.00%	$ -	0.1760	$ -	40.38
2016	$ -	10.5	21	100.00%	$ -	0.1940	$ -	39.49
2015	$ -	11.5	23	100.00%	$ -	0.2119	$ -	38.62
2014	$ -	12.5	26	100.00%	$ -	0.2385	$ -	37.31
2013	$ 8,571	13.5	28	100.00%	$ 8,571	0.2560	$ 2,194	36.46
2012	$ 21,662	14.5	30	100.00%	$ 21,662	0.2735	$ 5,925	35.60
2011	$ -	15.5	32	100.00%	$ -	0.2908	$ -	34.75
2010	$ -	16.5	34	100.00%	$ -	0.3079	$ -	33.91
2009	$ -	17.5	36	100.00%	$ -	0.3249	$ -	33.08
2008	$ 249,782	18.5	38	100.00%	$ 249,782	0.3418	$ 85,375	32.25
2007	$ 11,729	19.5	40	100.00%	$ 11,729	0.3585	$ 4,205	31.43
2006	$ 82,236	20.5	42	100.00%	$ 82,236	0.3750	$ 30,838	30.63
2005	$ 86,161	21.5	44	100.00%	$ 86,161	0.3914	$ 33,724	29.82
2004	$ 59,853	22.5	46	100.00%	$ 59,853	0.4076	$ 24,396	29.03
2003	$ 301,201	23.5	48	100.00%	$ 301,201	0.4236	$ 127,589	28.24
2002	$ 154,135	24.5	50	100.00%	$ 154,135	0.4395	$ 67,742	27.46
2001	$ 495,273	25.5	52	100.00%	$ 495,273	0.4551	$ 225,399	26.70
2000	$ 174,732	26.5	54	100.00%	$ 174,732	0.4706	$ 82,229	25.94
1999	$ 16,726	27.5	56	100.00%	$ 16,726	0.4859	$ 8,127	25.19
1998	$ 560,594	28.5	58	100.00%	$ 560,594	0.5010	$ 280,858	24.45
1997	$ 728,580	29.5	60	100.00%	$ 728,580	0.5159	$ 375,875	23.72
1996	$ 215,122	30.5	62	100.00%	$ 215,122	0.5306	$ 114,143	23.00
1995	$ 117,236	31.5	64	100.00%	$ 117,236	0.5450	$ 63,893	22.30
1994	$ 349,935	32.5	66	100.00%	$ 349,935	0.5593	$ 195,719	21.59
1993	$ 163,267	33.5	68	100.00%	$ 163,267	0.5733	$ 93,601	20.91
1992	$ 264,884	34.5	70	100.00%	$ 264,884	0.5871	$ 155,513	20.23
1991	$ 147,610	35.5	72	100.00%	$ 147,610	0.6007	$ 88,669	19.57
1990	$ 297,918	36.5	74	100.00%	$ 297,918	0.6140	$ 182,921	18.91

1989	$	41,659	37.5	77	100.00%	$	41,659	0.6336	$	26,395	17.95
1988	$	411,643	38.5	79	100.00%	$	411,643	0.6463	$	266,045	17.33
1987	$	52,185	39.5	81	100.00%	$	52,185	0.6587	$	34,375	16.72
1986	$	86,986	40.5	83	100.00%	$	86,986	0.6708	$	58,350	16.13
1985	$	86,880	41.5	85	100.00%	$	86,880	0.6826	$	59,304	15.55
1984	$	50,678	42.5	87	100.00%	$	50,678	0.6941	$	35,176	14.99
1983	$	24,048	43.5	89	100.00%	$	24,048	0.7053	$	16,961	14.44
1982	$	156,833	44.5	91	100.00%	$	156,833	0.7162	$	112,324	13.91
1981	$	82,437	45.5	93	100.00%	$	82,437	0.7268	$	59,915	13.39
1980	$	13,578	46.5	95	100.00%	$	13,578	0.7370	$	10,007	12.89
1979	$	41,008	47.5	97	100.00%	$	41,008	0.7469	$	30,629	12.40
1978	$	22,161	48.5	99	100.00%	$	22,161	0.7564	$	16,763	11.94
1977	$	14,833	49.5	101	100.00%	$	14,833	0.7656	$	11,356	11.49
1976	$	138,679	50.5	103	100.00%	$	138,679	0.7744	$	107,393	11.05
1975	$	30,468	51.5	105	100.00%	$	30,468	0.7829	$	23,853	10.64
1974	$	18,633	52.5	107	100.00%	$	18,633	0.7910	$	14,738	10.24
1973	$	12,037	53.5	109	100.00%	$	12,037	0.7988	$	9,615	9.86
1972	$	26,694	54.5	111	100.00%	$	26,694	0.8063	$	21,524	9.49
1971	$	26,308	55.5	113	100.00%	$	26,308	0.8134	$	21,399	9.14
1970	$	15,250	56.5	115	100.00%	$	15,250	0.8203	$	12,510	8.81
1969	$	32,278	57.5	117	100.00%	$	32,278	0.8268	$	26,688	8.49
1968	$	18,056	58.5	119	100.00%	$	18,056	0.8331	$	15,042	8.18
1967	$	18,626	59.5	121	100.00%	$	18,626	0.8391	$	15,629	7.88
1966	$	43,116	60.5	123	100.00%	$	43,116	0.8449	$	36,429	7.60
1965	$	16,408	61.5	126	100.00%	$	16,408	0.8532	$	13,999	7.19
1964	$	19,173	62.5	128	100.00%	$	19,173	0.8586	$	16,462	6.93
1963	$	5,203	63.5	130	100.00%	$	5,203	0.8637	$	4,494	6.68
1962	$	12,455	64.5	132	100.00%	$	12,455	0.8688	$	10,821	6.43
1961	$	5,498	65.5	134	100.00%	$	5,498	0.8737	$	4,804	6.19
1960	$	24,067	66.5	136	100.00%	$	24,067	0.8785	$	21,143	5.95
1959	$	9,802	67.5	138	100.00%	$	9,802	0.8833	$	8,658	5.72
1958	$	6,469	68.5	140	100.00%	$	6,469	0.8879	$	5,744	5.49
1957	$	13,575	69.5	142	100.00%	$	13,575	0.8925	$	12,115	5.27
1956	$	39,702	70.5	144	100.00%	$	39,702	0.8971	$	35,617	5.04
1955	$	7,542	71.5	146	100.00%	$	7,542	0.9015	$	6,799	4.83
1954	$	8,509	72.5	148	100.00%	$	8,509	0.9059	$	7,708	4.61
1953	$	5,944	73.5	150	100.00%	$	5,944	0.9103	$	5,411	4.40
1952	$	19	74.5	152	100.00%	$	19	0.9147	$	17	4.18
1951	$	-	75.5	154	100.00%	$	-	0.9190	$	-	3.97
1950	$	8	76.5	156	100.00%	$	8	0.9234	$	7	3.75
1949	$	-	77.5	158	100.00%	$	-	0.9279	$	-	3.53
1948	$	89	78.5	160	100.00%	$	89	0.9325	$	83	3.31
1947	$	277	79.5	162	100.00%	$	277	0.9373	$	260	3.07
1946	$	164	80.5	164	100.00%	$	164	0.9424	$	154	2.82
1945	$	174	81.5	166	100.00%	$	174	0.9477	$	165	2.56
1944	$	84	82.5	168	100.00%	$	84	0.9531	$	80	2.30
1943	$	208	83.5	170	100.00%	$	208	0.9587	$	199	2.02
1942	$	116	84.5	172	100.00%	$	116	0.9641	$	111	1.76
1941	$	-	85.5	174	100.00%	$	-	0.9694	$	-	1.50
1940	$	189	86.5	177	100.00%	$	189	0.9772	$	185	1.12
1939	$	200	87.5	179	100.00%	$	200	0.9823	$	196	0.87
1938	$	130	88.5	181	100.00%	$	130	0.9865	$	128	0.66
1937	$	63	89.5	183	100.00%	$	63	0.9917	$	63	0.41
1936	$	-	90.5	185	100.00%	$	-	1.0000	$	-	0.00
1935	$	1	91.5	187	100.00%	$	1	1.0000	$	1	0.00

1934	$ -	92.5	189	100.00%	$ -	1.0000	$ -	0.00
1933	$ -	93.5	191	100.00%	$ -	1.0000	$ -	0.00
1932	$ -	94.5	193	100.00%	$ -	1.0000	$ -	0.00
1931	$ -	95.5	195	100.00%	$ -	1.0000	$ -	0.00
1930	$ -	96.5	197	100.00%	$ -	1.0000	$ -	0.00
1929	$ -	97.5	199	100.00%	$ -	1.0000	$ -	0.00
1928	$ -	98.5	201	100.00%	$ -	1.0000	$ -	0.00
1927	$ 43	99.5	203	100.00%	$ 43	1.0000	$ 43	0.00
1926	$ -	100.5	205	100.00%	$ -	1.0000	$ -	0.00
1925	$ -	101.5	207	100.00%	$ -	1.0000	$ -	0.00
1924	$ -	102.5	209	100.00%	$ -	1.0000	$ -	0.00
1923	$ -	103.5	211	100.00%	$ -	1.0000	$ -	0.00
1922	$ -	104.5	213	100.00%	$ -	1.0000	$ -	0.00
1921	$ -	105.5	215	100.00%	$ -	1.0000	$ -	0.00
1920	$ -	106.5	217	100.00%	$ -	1.0000	$ -	0.00
1919	$ -	107.5	219	100.00%	$ -	1.0000	$ -	0.00
1918	$ -	108.5	221	100.00%	$ -	1.0000	$ -	0.00
1917	$ -	109.5	223	100.00%	$ -	1.0000	$ -	0.00
1916	$ -	110.5	226	100.00%	$ -	1.0000	$ -	0.00
1915	$ -	111.5	228	100.00%	$ -	1.0000	$ -	0.00
1914	$ -	112.5	230	100.00%	$ -	1.0000	$ -	0.00
1913	$ -	113.5	232	100.00%	$ -	1.0000	$ -	0.00
1912	$ -	114.5	234	100.00%	$ -	1.0000	$ -	0.00
1911	$ -	115.5	236	100.00%	$ -	1.0000	$ -	0.00
1910	$ -	116.5	238	100.00%	$ -	1.0000	$ -	0.00
1909	$ -	117.5	240	100.00%	$ -	1.0000	$ -	0.00
1908	$ -	118.5	242	100.00%	$ -	1.0000	$ -	0.00
1907	$ -	119.5	244	100.00%	$ -	1.0000	$ -	0.00
1906	$ -	120.5	246	100.00%	$ -	1.0000	$ -	0.00
1905	$ -	121.5	248	100.00%	$ -	1.0000	$ -	0.00
1904	$ -	122.5	250	100.00%	$ -	1.0000	$ -	0.00
1903	$ -	123.5	252	100.00%	$ -	1.0000	$ -	0.00
1902	$ -	124.5	254	100.00%	$ -	1.0000	$ -	0.00
1901	$ -	125.5	256	100.00%	$ -	1.0000	$ -	0.00
1900	$ -	126.5	258	100.00%	$ -	1.0000	$ -	0.00
1899	$ -	127.5	260	100.00%	$ -	1.0000	$ -	0.00
1898	$ -	128.5	262	100.00%	$ -	1.0000	$ -	0.00
1897	$ -	129.5	264	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	266	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	268	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	270	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	272	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	274	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	277	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	279	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	281	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	283	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	285	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	287	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	289	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	291	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	293	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	295	100.00%	$ -	1.0000	$ -	0.00
Total	$ 6,172,834				$ 6,172,834		$ 3,448,909	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 3,448,909	
Average Remaining Life		21.62
Theoretical Reserve %	55.87%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37000**
Plant Account **COMMUNICATION EQUIPMENT**

Survivor Curve R0.5
Average Service Life 23
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	2	100.00%	$ -	0.0124	$ -	22.71
2025	$ -	1.5	7	100.00%	$ -	0.0433	$ -	22.00
2024	$ -	2.5	11	100.00%	$ -	0.0679	$ -	21.44
2023	$ -	3.5	15	100.00%	$ -	0.0923	$ -	20.88
2022	$ 19,068	4.5	20	100.00%	$ 19,068	0.1227	$ 2,340	20.18
2021	$ -	5.5	24	100.00%	$ -	0.1468	$ -	19.62
2020	$ -	6.5	28	100.00%	$ -	0.1709	$ -	19.07
2019	$ -	7.5	33	100.00%	$ -	0.2008	$ -	18.38
2018	$ -	8.5	37	100.00%	$ -	0.2246	$ -	17.83
2017	$ -	9.5	41	100.00%	$ -	0.2483	$ -	17.29
2016	$ -	10.5	46	100.00%	$ -	0.2777	$ -	16.61
2015	$ 208,014	11.5	50	100.00%	$ 208,014	0.3010	$ 62,612	16.08
2014	$ 229,453	12.5	54	100.00%	$ 229,453	0.3241	$ 74,366	15.55
2013	$ 552,258	13.5	59	100.00%	$ 552,258	0.3527	$ 194,782	14.89
2012	$ 649,683	14.5	63	100.00%	$ 649,683	0.3753	$ 243,826	14.37
2011	$ 574,467	15.5	67	100.00%	$ 574,467	0.3975	$ 228,351	13.86
2010	$ 158,523	16.5	72	100.00%	$ 158,523	0.4249	$ 67,356	13.23
2009	$ 679,443	17.5	76	100.00%	$ 679,443	0.4465	$ 303,372	12.73
2008	$ -	18.5	80	100.00%	$ -	0.4677	$ -	12.24
2007	$ -	19.5	85	100.00%	$ -	0.4937	$ -	11.64
2006	$ -	20.5	89	100.00%	$ -	0.5141	$ -	11.18
2005	$ -	21.5	93	100.00%	$ -	0.5341	$ -	10.72
2004	$ 19,337	22.5	98	100.00%	$ 19,337	0.5586	$ 10,801	10.15
2003	$ -	23.5	102	100.00%	$ -	0.5778	$ -	9.71
2002	$ -	24.5	107	100.00%	$ -	0.6013	$ -	9.17
2001	$ 21,877	25.5	111	100.00%	$ 21,877	0.6196	$ 13,555	8.75
2000	$ 83,012	26.5	115	100.00%	$ 83,012	0.6377	$ 52,937	8.33
1999	$ -	27.5	120	100.00%	$ -	0.6597	$ -	7.83
1998	$ -	28.5	124	100.00%	$ -	0.6770	$ -	7.43
1997	$ 271	29.5	128	100.00%	$ 271	0.6941	$ 188	7.04
1996	$ 2,815	30.5	133	100.00%	$ 2,815	0.7149	$ 2,012	6.56
1995	$ 53,971	31.5	137	100.00%	$ 53,971	0.7314	$ 39,474	6.18
1994	$ 24,238	32.5	141	100.00%	$ 24,238	0.7476	$ 18,120	5.81
1993	$ 4,989	33.5	146	100.00%	$ 4,989	0.7677	$ 3,830	5.34
1992	$ 11,826	34.5	150	100.00%	$ 11,826	0.7836	$ 9,267	4.98
1991	$ 19,399	35.5	154	100.00%	$ 19,399	0.7994	$ 15,507	4.61
1990	$ 81,478	36.5	159	100.00%	$ 81,478	0.8192	$ 66,747	4.16

1989	$ 6,202	37.5	163	100.00%	$ 6,202	0.8352	$ 5,180	3.79
1988	$ 56,812	38.5	167	100.00%	$ 56,812	0.8513	$ 48,364	3.42
1987	$ 8,236	39.5	172	100.00%	$ 8,236	0.8717	$ 7,180	2.95
1986	$ 1,865	40.5	176	100.00%	$ 1,865	0.8885	$ 1,657	2.56
1985	$ 8,363	41.5	180	100.00%	$ 8,363	0.9058	$ 7,576	2.17
1984	$ 2,339	42.5	185	100.00%	$ 2,339	0.9282	$ 2,171	1.65
1983	$ 1,355	43.5	189	100.00%	$ 1,355	0.9468	$ 1,283	1.22
1982	$ 5,572	44.5	193	100.00%	$ 5,572	0.9657	$ 5,381	0.79
1981	$ -	45.5	198	100.00%	$ -	0.9900	$ -	0.23
1980	$ -	46.5	202	100.00%	$ -	1.0000	$ -	0.00
1979	$ 706	47.5	207	100.00%	$ 706	1.0000	$ 706	0.00
1978	$ -	48.5	211	100.00%	$ -	1.0000	$ -	0.00
1977	$ -	49.5	215	100.00%	$ -	1.0000	$ -	0.00
1976	$ -	50.5	220	100.00%	$ -	1.0000	$ -	0.00
1975	$ -	51.5	224	100.00%	$ -	1.0000	$ -	0.00
1974	$ -	52.5	228	100.00%	$ -	1.0000	$ -	0.00
1973	$ -	53.5	233	100.00%	$ -	1.0000	$ -	0.00
1972	$ 1,946	54.5	237	100.00%	$ 1,946	1.0000	$ 1,946	0.00
1971	$ -	55.5	241	100.00%	$ -	1.0000	$ -	0.00
1970	$ -	56.5	246	100.00%	$ -	1.0000	$ -	0.00
1969	$ -	57.5	250	100.00%	$ -	1.0000	$ -	0.00
1968	$ 2,500	58.5	254	100.00%	$ 2,500	1.0000	$ 2,500	0.00
1967	$ 250	59.5	259	100.00%	$ 250	1.0000	$ 250	0.00
1966	$ 1,743	60.5	263	100.00%	$ 1,743	1.0000	$ 1,743	0.00
1965	$ 7,728	61.5	267	100.00%	$ 7,728	1.0000	$ 7,728	0.00
1964	$ -	62.5	272	100.00%	$ -	1.0000	$ -	0.00
1963	$ -	63.5	276	100.00%	$ -	1.0000	$ -	0.00
1962	$ -	64.5	280	100.00%	$ -	1.0000	$ -	0.00
1961	$ -	65.5	285	100.00%	$ -	1.0000	$ -	0.00
1960	$ -	66.5	289	100.00%	$ -	1.0000	$ -	0.00
1959	$ -	67.5	293	100.00%	$ -	1.0000	$ -	0.00
1958	$ -	68.5	298	100.00%	$ -	1.0000	$ -	0.00
1957	$ -	69.5	302	100.00%	$ -	1.0000	$ -	0.00
1956	$ -	70.5	307	100.00%	$ -	1.0000	$ -	0.00
1955	$ 5,466	71.5	311	100.00%	$ 5,466	1.0000	$ 5,466	0.00
1954	$ -	72.5	315	100.00%	$ -	1.0000	$ -	0.00
1953	$ -	73.5	320	100.00%	$ -	1.0000	$ -	0.00
1952	$ -	74.5	324	100.00%	$ -	1.0000	$ -	0.00
1951	$ -	75.5	328	100.00%	$ -	1.0000	$ -	0.00
1950	$ -	76.5	333	100.00%	$ -	1.0000	$ -	0.00
1949	$ -	77.5	337	100.00%	$ -	1.0000	$ -	0.00
1948	$ -	78.5	341	100.00%	$ -	1.0000	$ -	0.00
1947	$ -	79.5	346	100.00%	$ -	1.0000	$ -	0.00
1946	$ -	80.5	350	100.00%	$ -	1.0000	$ -	0.00
1945	$ -	81.5	354	100.00%	$ -	1.0000	$ -	0.00
1944	$ -	82.5	359	100.00%	$ -	1.0000	$ -	0.00
1943	$ -	83.5	363	100.00%	$ -	1.0000	$ -	0.00
1942	$ -	84.5	367	100.00%	$ -	1.0000	$ -	0.00
1941	$ -	85.5	372	100.00%	$ -	1.0000	$ -	0.00
1940	$ -	86.5	376	100.00%	$ -	1.0000	$ -	0.00
1939	$ -	87.5	380	100.00%	$ -	1.0000	$ -	0.00
1938	$ -	88.5	385	100.00%	$ -	1.0000	$ -	0.00
1937	$ -	89.5	389	100.00%	$ -	1.0000	$ -	0.00
1936	$ -	90.5	393	100.00%	$ -	1.0000	$ -	0.00
1935	$ -	91.5	398	100.00%	$ -	1.0000	$ -	0.00

1934	$ -	92.5	402	100.00%	$ -	1.0000	$ -	0.00
1933	$ -	93.5	407	100.00%	$ -	1.0000	$ -	0.00
1932	$ -	94.5	411	100.00%	$ -	0.0000	$ -	23.00
1931	$ -	95.5	415	100.00%	$ -	0.0000	$ -	23.00
1930	$ -	96.5	420	100.00%	$ -	0.0000	$ -	23.00
1929	$ -	97.5	424	100.00%	$ -	0.0000	$ -	23.00
1928	$ -	98.5	428	100.00%	$ -	0.0000	$ -	23.00
1927	$ -	99.5	433	100.00%	$ -	0.0000	$ -	23.00
1926	$ -	100.5	437	100.00%	$ -	0.0000	$ -	23.00
1925	$ -	101.5	441	100.00%	$ -	0.0000	$ -	23.00
1924	$ -	102.5	446	100.00%	$ -	0.0000	$ -	23.00
1923	$ -	103.5	450	100.00%	$ -	0.0000	$ -	23.00
1922	$ -	104.5	454	100.00%	$ -	0.0000	$ -	23.00
1921	$ -	105.5	459	100.00%	$ -	0.0000	$ -	23.00
1920	$ -	106.5	463	100.00%	$ -	0.0000	$ -	23.00
1919	$ -	107.5	467	100.00%	$ -	0.0000	$ -	23.00
1918	$ -	108.5	472	100.00%	$ -	0.0000	$ -	23.00
1917	$ -	109.5	476	100.00%	$ -	0.0000	$ -	23.00
1916	$ -	110.5	480	100.00%	$ -	0.0000	$ -	23.00
1915	$ -	111.5	485	100.00%	$ -	0.0000	$ -	23.00
1914	$ -	112.5	489	100.00%	$ -	0.0000	$ -	23.00
1913	$ -	113.5	493	100.00%	$ -	0.0000	$ -	23.00
1912	$ -	114.5	498	100.00%	$ -	0.0000	$ -	23.00
1911	$ -	115.5	502	100.00%	$ -	0.0000	$ -	23.00
1910	$ -	116.5	507	100.00%	$ -	0.0000	$ -	23.00
1909	$ -	117.5	511	100.00%	$ -	0.0000	$ -	23.00
1908	$ -	118.5	515	100.00%	$ -	0.0000	$ -	23.00
1907	$ -	119.5	520	100.00%	$ -	0.0000	$ -	23.00
1906	$ -	120.5	524	100.00%	$ -	0.0000	$ -	23.00
1905	$ -	121.5	528	100.00%	$ -	0.0000	$ -	23.00
1904	$ -	122.5	533	100.00%	$ -	0.0000	$ -	23.00
1903	$ -	123.5	537	100.00%	$ -	0.0000	$ -	23.00
1902	$ -	124.5	541	100.00%	$ -	0.0000	$ -	23.00
1901	$ -	125.5	546	100.00%	$ -	0.0000	$ -	23.00
1900	$ -	126.5	550	100.00%	$ -	0.0000	$ -	23.00
1899	$ -	127.5	554	100.00%	$ -	0.0000	$ -	23.00
1898	$ -	128.5	559	100.00%	$ -	0.0000	$ -	23.00
1897	$ -	129.5	563	100.00%	$ -	0.0000	$ -	23.00
1896	$ -	130.5	567	100.00%	$ -	0.0000	$ -	23.00
1895	$ -	131.5	572	100.00%	$ -	0.0000	$ -	23.00
1894	$ -	132.5	576	100.00%	$ -	0.0000	$ -	23.00
1893	$ -	133.5	580	100.00%	$ -	0.0000	$ -	23.00
1892	$ -	134.5	585	100.00%	$ -	0.0000	$ -	23.00
1891	$ -	135.5	589	100.00%	$ -	0.0000	$ -	23.00
1890	$ -	136.5	593	100.00%	$ -	0.0000	$ -	23.00
1889	$ -	137.5	598	100.00%	$ -	0.0000	$ -	23.00
1888	$ -	138.5	602	100.00%	$ -	0.0000	$ -	23.00
1887	$ -	139.5	607	100.00%	$ -	0.0000	$ -	23.00
1886	$ -	140.5	611	100.00%	$ -	0.0000	$ -	23.00
1885	$ -	141.5	615	100.00%	$ -	0.0000	$ -	23.00
1884	$ -	142.5	620	100.00%	$ -	0.0000	$ -	23.00
1883	$ -	143.5	624	100.00%	$ -	0.0000	$ -	23.00
1882	$ -	144.5	628	100.00%	$ -	0.0000	$ -	23.00
Total	$ 3,505,204				$ 3,505,204		$ 1,508,574	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 1,508,574	
Average Remaining Life		13.10
Theoretical Reserve %	43.04%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37100**
Plant Account **OTHER EQUIPMENT**

Survivor Curve R2.5
Average Service Life 35
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0095	$ -	34.67
2025	$ -	1.5	4	100.00%	$ -	0.0377	$ -	33.68
2024	$ -	2.5	7	100.00%	$ -	0.0658	$ -	32.70
2023	$ -	3.5	10	100.00%	$ -	0.0936	$ -	31.72
2022	$ -	4.5	13	100.00%	$ -	0.1213	$ -	30.75
2021	$ -	5.5	16	100.00%	$ -	0.1488	$ -	29.79
2020	$ -	6.5	19	100.00%	$ -	0.1760	$ -	28.84
2019	$ -	7.5	21	100.00%	$ -	0.1940	$ -	28.21
2018	$ -	8.5	24	100.00%	$ -	0.2208	$ -	27.27
2017	$ -	9.5	27	100.00%	$ -	0.2473	$ -	26.34
2016	$ -	10.5	30	100.00%	$ -	0.2735	$ -	25.43
2015	$ -	11.5	33	100.00%	$ -	0.2994	$ -	24.52
2014	$ -	12.5	36	100.00%	$ -	0.3249	$ -	23.63
2013	$ -	13.5	39	100.00%	$ -	0.3502	$ -	22.74
2012	$ -	14.5	41	100.00%	$ -	0.3668	$ -	22.16
2011	$ -	15.5	44	100.00%	$ -	0.3914	$ -	21.30
2010	$ -	16.5	47	100.00%	$ -	0.4156	$ -	20.45
2009	$ -	17.5	50	100.00%	$ -	0.4395	$ -	19.62
2008	$ -	18.5	53	100.00%	$ -	0.4629	$ -	18.80
2007	$ -	19.5	56	100.00%	$ -	0.4859	$ -	17.99
2006	$ -	20.5	59	100.00%	$ -	0.5084	$ -	17.21
2005	$ -	21.5	61	100.00%	$ -	0.5232	$ -	16.69
2004	$ -	22.5	64	100.00%	$ -	0.5450	$ -	15.93
2003	$ -	23.5	67	100.00%	$ -	0.5663	$ -	15.18
2002	$ -	24.5	70	100.00%	$ -	0.5871	$ -	14.45
2001	$ -	25.5	73	100.00%	$ -	0.6074	$ -	13.74
2000	$ -	26.5	76	100.00%	$ -	0.6271	$ -	13.05
1999	$ -	27.5	79	100.00%	$ -	0.6463	$ -	12.38
1998	$ -	28.5	81	100.00%	$ -	0.6587	$ -	11.95
1997	$ -	29.5	84	100.00%	$ -	0.6767	$ -	11.32
1996	$ -	30.5	87	100.00%	$ -	0.6941	$ -	10.71
1995	$ 7,819	31.5	90	100.00%	$ 7,819	0.7108	$ 5,557	10.12
1994	$ 3,880	32.5	93	100.00%	$ 3,880	0.7268	$ 2,820	9.56
1993	$ 9,905	33.5	96	100.00%	$ 9,905	0.7420	$ 7,350	9.03
1992	$ 10,562	34.5	99	100.00%	$ 10,562	0.7564	$ 7,989	8.53
1991	$ 14,350	35.5	101	100.00%	$ 14,350	0.7656	$ 10,987	8.20
1990	$ 14,888	36.5	104	100.00%	$ 14,888	0.7787	$ 11,594	7.75

1989	$	11,463	37.5	107	100.00%	$	11,463	0.7910	$	9,067	7.32
1988	$	7,216	38.5	110	100.00%	$	7,216	0.8026	$	5,791	6.91
1987	$	1,617	39.5	113	100.00%	$	1,617	0.8134	$	1,316	6.53
1986	$	1,467	40.5	116	100.00%	$	1,467	0.8236	$	1,208	6.17
1985	$	5,293	41.5	119	100.00%	$	5,293	0.8331	$	4,409	5.84
1984	$	3,634	42.5	121	100.00%	$	3,634	0.8391	$	3,049	5.63
1983	$	3,348	43.5	124	100.00%	$	3,348	0.8478	$	2,839	5.33
1982	$	4,310	44.5	127	100.00%	$	4,310	0.8559	$	3,689	5.04
1981	$	1,410	45.5	130	100.00%	$	1,410	0.8637	$	1,218	4.77
1980	$	1,157	46.5	133	100.00%	$	1,157	0.8712	$	1,008	4.51
1979	$	1,490	47.5	136	100.00%	$	1,490	0.8785	$	1,309	4.25
1978	$	396	48.5	139	100.00%	$	396	0.8856	$	351	4.00
1977	$	2,372	49.5	141	100.00%	$	2,372	0.8902	$	2,112	3.84
1976	$	667	50.5	144	100.00%	$	667	0.8971	$	598	3.60
1975	$	729	51.5	147	100.00%	$	729	0.9038	$	658	3.37
1974	$	773	52.5	150	100.00%	$	773	0.9103	$	704	3.14
1973	$	2,116	53.5	153	100.00%	$	2,116	0.9169	$	1,940	2.91
1972	$	6,378	54.5	156	100.00%	$	6,378	0.9234	$	5,890	2.68
1971	$	4,402	55.5	159	100.00%	$	4,402	0.9302	$	4,095	2.44
1970	$	2,302	56.5	161	100.00%	$	2,302	0.9349	$	2,153	2.28
1969	$	1,295	57.5	164	100.00%	$	1,295	0.9424	$	1,220	2.02
1968	$	8,185	58.5	167	100.00%	$	8,185	0.9504	$	7,779	1.74
1967	$	1,046	59.5	170	100.00%	$	1,046	0.9587	$	1,003	1.45
1966	$	1,610	60.5	173	100.00%	$	1,610	0.9668	$	1,557	1.16
1965	$	238	61.5	176	100.00%	$	238	0.9745	$	232	0.89
1964	$	542	62.5	179	100.00%	$	542	0.9823	$	533	0.62
1963	$	-	63.5	181	100.00%	$	-	0.9865	$	-	0.47
1962	$	269	64.5	184	100.00%	$	269	0.9950	$	267	0.18
1961	$	-	65.5	187	100.00%	$	-	1.0000	$	-	0.00
1960	$	-	66.5	190	100.00%	$	-	1.0000	$	-	0.00
1959	$	1,631	67.5	193	100.00%	$	1,631	1.0000	$	1,631	0.00
1958	$	54	68.5	196	100.00%	$	54	1.0000	$	54	0.00
1957	$	-	69.5	199	100.00%	$	-	1.0000	$	-	0.00
1956	$	802	70.5	201	100.00%	$	802	1.0000	$	802	0.00
1955	$	-	71.5	204	100.00%	$	-	1.0000	$	-	0.00
1954	$	-	72.5	207	100.00%	$	-	1.0000	$	-	0.00
1953	$	-	73.5	210	100.00%	$	-	1.0000	$	-	0.00
1952	$	193	74.5	213	100.00%	$	193	1.0000	$	193	0.00
1951	$	-	75.5	216	100.00%	$	-	1.0000	$	-	0.00
1950	$	-	76.5	219	100.00%	$	-	1.0000	$	-	0.00
1949	$	-	77.5	221	100.00%	$	-	1.0000	$	-	0.00
1948	$	-	78.5	224	100.00%	$	-	1.0000	$	-	0.00
1947	$	-	79.5	227	100.00%	$	-	1.0000	$	-	0.00
1946	$	-	80.5	230	100.00%	$	-	1.0000	$	-	0.00
1945	$	-	81.5	233	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	236	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	239	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	241	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	244	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	247	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	250	100.00%	$	-	1.0000	$	-	0.00
1938	$	348	88.5	253	100.00%	$	348	1.0000	$	348	0.00
1937	$	76	89.5	256	100.00%	$	76	1.0000	$	76	0.00
1936	$	-	90.5	259	100.00%	$	-	1.0000	$	-	0.00
1935	$	149	91.5	261	100.00%	$	149	1.0000	$	149	0.00

1934	$	160	92.5	264	100.00%	$	160	1.0000	$	160	0.00
1933	$	-	93.5	267	100.00%	$	-	1.0000	$	-	0.00
1932	$	23	94.5	270	100.00%	$	23	1.0000	$	23	0.00
1931	$	73	95.5	273	100.00%	$	73	1.0000	$	73	0.00
1930	$	-	96.5	276	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	279	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	281	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	284	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	287	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	290	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	293	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	296	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	299	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	301	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	304	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	307	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	310	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	313	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	316	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	319	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	321	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	324	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	327	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	330	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	333	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	336	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	339	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	341	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	344	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	347	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	350	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	353	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	356	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	359	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	361	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	364	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	367	100.00%	$	-	1.0000	$	-	0.00
1897	$	-	129.5	370	100.00%	$	-	1.0000	$	-	0.00
1896	$	-	130.5	373	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	376	100.00%	$	-	1.0000	$	-	0.00
1894	$	-	132.5	379	100.00%	$	-	1.0000	$	-	0.00
1893	$	-	133.5	381	100.00%	$	-	1.0000	$	-	0.00
1892	$	-	134.5	384	100.00%	$	-	1.0000	$	-	0.00
1891	$	-	135.5	387	100.00%	$	-	1.0000	$	-	0.00
1890	$	-	136.5	390	100.00%	$	-	1.0000	$	-	0.00
1889	$	-	137.5	393	100.00%	$	-	1.0000	$	-	0.00
1888	$	-	138.5	396	100.00%	$	-	1.0000	$	-	0.00
1887	$	-	139.5	399	100.00%	$	-	1.0000	$	-	0.00
1886	$	-	140.5	401	100.00%	$	-	1.0000	$	-	0.00
1885	$	-	141.5	404	100.00%	$	-	1.0000	$	-	0.00
1884	$	-	142.5	407	100.00%	$	-	1.0000	$	-	0.00
1883	$	-	143.5	410	100.00%	$	-	0.0000	$	-	35.00
1882	$	-	144.5	413	100.00%	$	-	0.0000	$	-	35.00
Total	$	140,637				$	140,637		$	115,801	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 115,801	
Average Remaining Life		6.18
Theoretical Reserve %	82.34%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37110**
Plant Account **TESTING EQUIPMENT**

Survivor Curve R3
Average Service Life 20
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	3	100.00%	$ -	0.0295	$ -	19.41
2025	$ -	1.5	8	100.00%	$ -	0.0784	$ -	18.43
2024	$ -	2.5	13	100.00%	$ -	0.1269	$ -	17.46
2023	$ -	3.5	18	100.00%	$ -	0.1748	$ -	16.50
2022	$ -	4.5	23	100.00%	$ -	0.2221	$ -	15.56
2021	$ -	5.5	28	100.00%	$ -	0.2687	$ -	14.63
2020	$ -	6.5	33	100.00%	$ -	0.3144	$ -	13.71
2019	$ -	7.5	38	100.00%	$ -	0.3591	$ -	12.82
2018	$ -	8.5	43	100.00%	$ -	0.4028	$ -	11.94
2017	$ -	9.5	48	100.00%	$ -	0.4454	$ -	11.09
2016	$ -	10.5	53	100.00%	$ -	0.4868	$ -	10.26
2015	$ 100,389	11.5	58	100.00%	$ 100,389	0.5268	$ 52,885	9.46
2014	$ -	12.5	63	100.00%	$ -	0.5656	$ -	8.69
2013	$ -	13.5	68	100.00%	$ -	0.6029	$ -	7.94
2012	$ -	14.5	73	100.00%	$ -	0.6387	$ -	7.23
2011	$ -	15.5	78	100.00%	$ -	0.6727	$ -	6.55
2010	$ -	16.5	83	100.00%	$ -	0.7049	$ -	5.90
2009	$ -	17.5	88	100.00%	$ -	0.7351	$ -	5.30
2008	$ -	18.5	93	100.00%	$ -	0.7630	$ -	4.74
2007	$ -	19.5	98	100.00%	$ -	0.7887	$ -	4.23
2006	$ -	20.5	103	100.00%	$ -	0.8119	$ -	3.76
2005	$ -	21.5	108	100.00%	$ -	0.8328	$ -	3.34
2004	$ -	22.5	113	100.00%	$ -	0.8515	$ -	2.97
2003	$ -	23.5	118	100.00%	$ -	0.8682	$ -	2.64
2002	$ -	24.5	123	100.00%	$ -	0.8833	$ -	2.33
2001	$ -	25.5	128	100.00%	$ -	0.8972	$ -	2.06
2000	$ -	26.5	133	100.00%	$ -	0.9104	$ -	1.79
1999	$ -	27.5	138	100.00%	$ -	0.9233	$ -	1.53
1998	$ -	28.5	143	100.00%	$ -	0.9362	$ -	1.28
1997	$ -	29.5	148	100.00%	$ -	0.9490	$ -	1.02
1996	$ 494	30.5	153	100.00%	$ 494	0.9616	$ 475	0.77
1995	$ 24,386	31.5	158	100.00%	$ 24,386	0.9737	$ 23,744	0.53
1994	$ -	32.5	163	100.00%	$ -	0.9853	$ -	0.29
1993	$ -	33.5	168	100.00%	$ -	0.9950	$ -	0.10
1992	$ 1,383	34.5	173	100.00%	$ 1,383	1.0000	$ 1,383	0.00
1991	$ 2,200	35.5	178	100.00%	$ 2,200	1.0000	$ 2,200	0.00
1990	$ 11,963	36.5	183	100.00%	$ 11,963	1.0000	$ 11,963	0.00

1989	$	-	37.5	188	100.00%	$	-	1.0000	$	-	0.00
1988	$	-	38.5	193	100.00%	$	-	1.0000	$	-	0.00
1987	$	-	39.5	198	100.00%	$	-	1.0000	$	-	0.00
1986	$	38,022	40.5	203	100.00%	$	38,022	1.0000	$	38,022	0.00
1985	$	4,385	41.5	208	100.00%	$	4,385	1.0000	$	4,385	0.00
1984	$	-	42.5	213	100.00%	$	-	1.0000	$	-	0.00
1983	$	11,125	43.5	218	100.00%	$	11,125	1.0000	$	11,125	0.00
1982	$	15,664	44.5	223	100.00%	$	15,664	1.0000	$	15,664	0.00
1981	$	-	45.5	228	100.00%	$	-	1.0000	$	-	0.00
1980	$	-	46.5	233	100.00%	$	-	1.0000	$	-	0.00
1979	$	-	47.5	238	100.00%	$	-	1.0000	$	-	0.00
1978	$	-	48.5	243	100.00%	$	-	1.0000	$	-	0.00
1977	$	-	49.5	248	100.00%	$	-	1.0000	$	-	0.00
1976	$	-	50.5	253	100.00%	$	-	1.0000	$	-	0.00
1975	$	-	51.5	258	100.00%	$	-	1.0000	$	-	0.00
1974	$	-	52.5	263	100.00%	$	-	1.0000	$	-	0.00
1973	$	-	53.5	268	100.00%	$	-	1.0000	$	-	0.00
1972	$	-	54.5	273	100.00%	$	-	1.0000	$	-	0.00
1971	$	-	55.5	278	100.00%	$	-	1.0000	$	-	0.00
1970	$	-	56.5	283	100.00%	$	-	1.0000	$	-	0.00
1969	$	-	57.5	288	100.00%	$	-	1.0000	$	-	0.00
1968	$	-	58.5	293	100.00%	$	-	1.0000	$	-	0.00
1967	$	-	59.5	298	100.00%	$	-	1.0000	$	-	0.00
1966	$	-	60.5	303	100.00%	$	-	1.0000	$	-	0.00
1965	$	-	61.5	308	100.00%	$	-	1.0000	$	-	0.00
1964	$	-	62.5	313	100.00%	$	-	1.0000	$	-	0.00
1963	$	-	63.5	318	100.00%	$	-	1.0000	$	-	0.00
1962	$	-	64.5	323	100.00%	$	-	1.0000	$	-	0.00
1961	$	-	65.5	328	100.00%	$	-	1.0000	$	-	0.00
1960	$	-	66.5	333	100.00%	$	-	1.0000	$	-	0.00
1959	$	-	67.5	338	100.00%	$	-	1.0000	$	-	0.00
1958	$	-	68.5	343	100.00%	$	-	1.0000	$	-	0.00
1957	$	-	69.5	348	100.00%	$	-	1.0000	$	-	0.00
1956	$	-	70.5	353	100.00%	$	-	1.0000	$	-	0.00
1955	$	-	71.5	358	100.00%	$	-	1.0000	$	-	0.00
1954	$	-	72.5	363	100.00%	$	-	1.0000	$	-	0.00
1953	$	-	73.5	368	100.00%	$	-	1.0000	$	-	0.00
1952	$	-	74.5	373	100.00%	$	-	1.0000	$	-	0.00
1951	$	-	75.5	378	100.00%	$	-	1.0000	$	-	0.00
1950	$	-	76.5	383	100.00%	$	-	1.0000	$	-	0.00
1949	$	-	77.5	388	100.00%	$	-	1.0000	$	-	0.00
1948	$	-	78.5	393	100.00%	$	-	1.0000	$	-	0.00
1947	$	-	79.5	398	100.00%	$	-	1.0000	$	-	0.00
1946	$	-	80.5	403	100.00%	$	-	1.0000	$	-	0.00
1945	$	-	81.5	408	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	413	100.00%	$	-	0.0000	$	-	20.00
1943	$	-	83.5	418	100.00%	$	-	0.0000	$	-	20.00
1942	$	-	84.5	423	100.00%	$	-	0.0000	$	-	20.00
1941	$	-	85.5	428	100.00%	$	-	0.0000	$	-	20.00
1940	$	-	86.5	433	100.00%	$	-	0.0000	$	-	20.00
1939	$	-	87.5	438	100.00%	$	-	0.0000	$	-	20.00
1938	$	-	88.5	443	100.00%	$	-	0.0000	$	-	20.00
1937	$	-	89.5	448	100.00%	$	-	0.0000	$	-	20.00
1936	$	-	90.5	453	100.00%	$	-	0.0000	$	-	20.00
1935	$	-	91.5	458	100.00%	$	-	0.0000	$	-	20.00

1934	$	-	92.5	463	100.00%	$	-	0.0000	$	-	20.00
1933	$	-	93.5	468	100.00%	$	-	0.0000	$	-	20.00
1932	$	-	94.5	473	100.00%	$	-	0.0000	$	-	20.00
1931	$	-	95.5	478	100.00%	$	-	0.0000	$	-	20.00
1930	$	-	96.5	483	100.00%	$	-	0.0000	$	-	20.00
1929	$	-	97.5	488	100.00%	$	-	0.0000	$	-	20.00
1928	$	-	98.5	493	100.00%	$	-	0.0000	$	-	20.00
1927	$	-	99.5	498	100.00%	$	-	0.0000	$	-	20.00
1926	$	-	100.5	503	100.00%	$	-	0.0000	$	-	20.00
1925	$	-	101.5	508	100.00%	$	-	0.0000	$	-	20.00
1924	$	-	102.5	513	100.00%	$	-	0.0000	$	-	20.00
1923	$	-	103.5	518	100.00%	$	-	0.0000	$	-	20.00
1922	$	-	104.5	523	100.00%	$	-	0.0000	$	-	20.00
1921	$	-	105.5	528	100.00%	$	-	0.0000	$	-	20.00
1920	$	-	106.5	533	100.00%	$	-	0.0000	$	-	20.00
1919	$	-	107.5	538	100.00%	$	-	0.0000	$	-	20.00
1918	$	-	108.5	543	100.00%	$	-	0.0000	$	-	20.00
1917	$	-	109.5	548	100.00%	$	-	0.0000	$	-	20.00
1916	$	-	110.5	553	100.00%	$	-	0.0000	$	-	20.00
1915	$	-	111.5	558	100.00%	$	-	0.0000	$	-	20.00
1914	$	-	112.5	563	100.00%	$	-	0.0000	$	-	20.00
1913	$	-	113.5	568	100.00%	$	-	0.0000	$	-	20.00
1912	$	-	114.5	573	100.00%	$	-	0.0000	$	-	20.00
1911	$	-	115.5	578	100.00%	$	-	0.0000	$	-	20.00
1910	$	-	116.5	583	100.00%	$	-	0.0000	$	-	20.00
1909	$	-	117.5	588	100.00%	$	-	0.0000	$	-	20.00
1908	$	-	118.5	593	100.00%	$	-	0.0000	$	-	20.00
1907	$	-	119.5	598	100.00%	$	-	0.0000	$	-	20.00
1906	$	-	120.5	603	100.00%	$	-	0.0000	$	-	20.00
1905	$	-	121.5	608	100.00%	$	-	0.0000	$	-	20.00
1904	$	-	122.5	613	100.00%	$	-	0.0000	$	-	20.00
1903	$	-	123.5	618	100.00%	$	-	0.0000	$	-	20.00
1902	$	-	124.5	623	100.00%	$	-	0.0000	$	-	20.00
1901	$	-	125.5	628	100.00%	$	-	0.0000	$	-	20.00
1900	$	-	126.5	633	100.00%	$	-	0.0000	$	-	20.00
1899	$	-	127.5	638	100.00%	$	-	0.0000	$	-	20.00
1898	$	-	128.5	643	100.00%	$	-	0.0000	$	-	20.00
1897	$	-	129.5	648	100.00%	$	-	0.0000	$	-	20.00
1896	$	-	130.5	653	100.00%	$	-	0.0000	$	-	20.00
1895	$	-	131.5	658	100.00%	$	-	0.0000	$	-	20.00
1894	$	-	132.5	663	100.00%	$	-	0.0000	$	-	20.00
1893	$	-	133.5	668	100.00%	$	-	0.0000	$	-	20.00
1892	$	-	134.5	673	100.00%	$	-	0.0000	$	-	20.00
1891	$	-	135.5	678	100.00%	$	-	0.0000	$	-	20.00
1890	$	-	136.5	683	100.00%	$	-	0.0000	$	-	20.00
1889	$	-	137.5	688	100.00%	$	-	0.0000	$	-	20.00
1888	$	-	138.5	693	100.00%	$	-	0.0000	$	-	20.00
1887	$	-	139.5	698	100.00%	$	-	0.0000	$	-	20.00
1886	$	-	140.5	703	100.00%	$	-	0.0000	$	-	20.00
1885	$	-	141.5	708	100.00%	$	-	0.0000	$	-	20.00
1884	$	-	142.5	713	100.00%	$	-	0.0000	$	-	20.00
1883	$	-	143.5	718	100.00%	$	-	0.0000	$	-	20.00
1882	$	-	144.5	723	100.00%	$	-	0.0000	$	-	20.00
Total	$	210,011				$	210,011		$	161,846	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 161,846	
Average Remaining Life		4.59
Theoretical Reserve %	77.07%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37420**
Plant Account **RIGHTS-OF-WAY**

Survivor Curve R3
Average Service Life 75
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0098	$ -	74.27
2025	$ -	1.5	2	100.00%	$ -	0.0197	$ -	73.52
2024	$ -	2.5	3	100.00%	$ -	0.0295	$ -	72.79
2023	$ -	3.5	5	100.00%	$ -	0.0491	$ -	71.32
2022	$ -	4.5	6	100.00%	$ -	0.0589	$ -	70.58
2021	$ -	5.5	7	100.00%	$ -	0.0686	$ -	69.86
2020	$ -	6.5	9	100.00%	$ -	0.0881	$ -	68.39
2019	$ 189	7.5	10	100.00%	$ 189	0.0978	$ 18	67.67
2018	$ 1,675	8.5	11	100.00%	$ 1,675	0.1075	$ 180	66.94
2017	$ 88,797	9.5	13	100.00%	$ 88,797	0.1269	$ 11,268	65.48
2016	$ 108,947	10.5	14	100.00%	$ 108,947	0.1365	$ 14,871	64.76
2015	$ 2,376	11.5	15	100.00%	$ 2,376	0.1461	$ 347	64.04
2014	$ 11,063	12.5	17	100.00%	$ 11,063	0.1653	$ 1,829	62.60
2013	$ 93,193	13.5	18	100.00%	$ 93,193	0.1748	$ 16,290	61.89
2012	$ 7,944	14.5	19	100.00%	$ 7,944	0.1843	$ 1,464	61.18
2011	$ 20,777	15.5	21	100.00%	$ 20,777	0.2033	$ 4,224	59.75
2010	$ 18,300	16.5	22	100.00%	$ 18,300	0.2127	$ 3,893	59.05
2009	$ 5,977	17.5	23	100.00%	$ 5,977	0.2221	$ 1,328	58.34
2008	$ 132,857	18.5	25	100.00%	$ 132,857	0.2408	$ 31,992	56.94
2007	$ 21,366	19.5	26	100.00%	$ 21,366	0.2501	$ 5,344	56.24
2006	$ 21,099	20.5	27	100.00%	$ 21,099	0.2594	$ 5,473	55.55
2005	$ 99,248	21.5	29	100.00%	$ 99,248	0.2779	$ 27,581	54.16
2004	$ 503,472	22.5	30	100.00%	$ 503,472	0.2871	$ 144,547	53.47
2003	$ 48,988	23.5	31	100.00%	$ 48,988	0.2962	$ 14,510	52.79
2002	$ 51,470	24.5	33	100.00%	$ 51,470	0.3144	$ 16,182	51.42
2001	$ 49,858	25.5	34	100.00%	$ 49,858	0.3234	$ 16,124	50.75
2000	$ 148,696	26.5	35	100.00%	$ 148,696	0.3324	$ 49,426	50.07
1999	$ 109,098	27.5	37	100.00%	$ 109,098	0.3503	$ 38,217	48.73
1998	$ 219,808	28.5	38	100.00%	$ 219,808	0.3591	$ 78,933	48.07
1997	$ 147,067	29.5	39	100.00%	$ 147,067	0.3679	$ 54,106	47.41
1996	$ 101,676	30.5	41	100.00%	$ 101,676	0.3855	$ 39,196	46.09
1995	$ 64,142	31.5	42	100.00%	$ 64,142	0.3942	$ 25,285	45.44
1994	$ 63,759	32.5	43	100.00%	$ 63,759	0.4028	$ 25,682	44.79
1993	$ 94,389	33.5	45	100.00%	$ 94,389	0.4200	$ 39,643	43.50
1992	$ 74,878	34.5	46	100.00%	$ 74,878	0.4285	$ 32,085	42.86

1991	$	69,791	35.5	47	100.00%	$	69,791	0.4370	$	30,499	42.23
1990	$	76,971	36.5	49	100.00%	$	76,971	0.4538	$	34,930	40.97
1989	$	63,294	37.5	50	100.00%	$	63,294	0.4621	$	29,248	40.34
1988	$	64,488	38.5	51	100.00%	$	64,488	0.4704	$	30,335	39.72
1987	$	61,591	39.5	53	100.00%	$	61,591	0.4868	$	29,982	38.49
1986	$	74,675	40.5	54	100.00%	$	74,675	0.4949	$	36,957	37.88
1985	$	70,214	41.5	55	100.00%	$	70,214	0.5029	$	35,311	37.28
1984	$	51,245	42.5	57	100.00%	$	51,245	0.5189	$	26,591	36.08
1983	$	47,020	43.5	58	100.00%	$	47,020	0.5268	$	24,770	35.49
1982	$	29,660	44.5	59	100.00%	$	29,660	0.5347	$	15,859	34.90
1981	$	41,645	45.5	61	100.00%	$	41,645	0.5503	$	22,917	33.73
1980	$	38,526	46.5	62	100.00%	$	38,526	0.5580	$	21,498	33.15
1979	$	27,735	47.5	63	100.00%	$	27,735	0.5656	$	15,687	32.58
1978	$	24,834	48.5	65	100.00%	$	24,834	0.5807	$	14,421	31.45
1977	$	19,182	49.5	66	100.00%	$	19,182	0.5882	$	11,283	30.89
1976	$	13,899	50.5	67	100.00%	$	13,899	0.5956	$	8,278	30.33
1975	$	37,864	51.5	69	100.00%	$	37,864	0.6102	$	23,104	29.24
1974	$	49,273	52.5	70	100.00%	$	49,273	0.6174	$	30,421	28.70
1973	$	38,365	53.5	71	100.00%	$	38,365	0.6245	$	23,959	28.16
1972	$	18,499	54.5	73	100.00%	$	18,499	0.6387	$	11,815	27.10
1971	$	15,534	55.5	74	100.00%	$	15,534	0.6456	$	10,029	26.58
1970	$	6,080	56.5	75	100.00%	$	6,080	0.6525	$	3,967	26.06
1969	$	11,282	57.5	77	100.00%	$	11,282	0.6661	$	7,515	25.04
1968	$	18,362	58.5	78	100.00%	$	18,362	0.6727	$	12,352	24.55
1967	$	36,084	59.5	79	100.00%	$	36,084	0.6793	$	24,512	24.05
1966	$	14,200	60.5	81	100.00%	$	14,200	0.6923	$	9,831	23.08
1965	$	1,905	61.5	82	100.00%	$	1,905	0.6986	$	1,331	22.61
1964	$	2,424	62.5	83	100.00%	$	2,424	0.7049	$	1,709	22.13
1963	$	1,025	63.5	85	100.00%	$	1,025	0.7172	$	735	21.21
1962	$	535	64.5	86	100.00%	$	535	0.7233	$	387	20.75
1961	$	1,740	65.5	87	100.00%	$	1,740	0.7292	$	1,269	20.31
1960	$	1,140	66.5	89	100.00%	$	1,140	0.7409	$	844	19.43
1959	$	1,432	67.5	90	100.00%	$	1,432	0.7465	$	1,069	19.01
1958	$	1,137	68.5	91	100.00%	$	1,137	0.7521	$	855	18.59
1957	$	5,278	69.5	93	100.00%	$	5,278	0.7630	$	4,027	17.78
1956	$	1,794	70.5	94	100.00%	$	1,794	0.7684	$	1,379	17.37
1955	$	3,133	71.5	95	100.00%	$	3,133	0.7736	$	2,424	16.98
1954	$	878	72.5	97	100.00%	$	878	0.7837	$	688	16.22
1953	$	1,145	73.5	98	100.00%	$	1,145	0.7887	$	903	15.85
1952	$	287	74.5	99	100.00%	$	287	0.7935	$	228	15.49
1951	$	360	75.5	101	100.00%	$	360	0.8029	$	289	14.78
1950	$	1,727	76.5	102	100.00%	$	1,727	0.8075	$	1,394	14.44
1949	$	2,078	77.5	103	100.00%	$	2,078	0.8119	$	1,687	14.11
1948	$	51	78.5	105	100.00%	$	51	0.8206	$	42	13.46
1947	$	236	79.5	106	100.00%	$	236	0.8247	$	194	13.15
1946	$	160	80.5	107	100.00%	$	160	0.8288	$	133	12.84
1945	$	60	81.5	109	100.00%	$	60	0.8367	$	50	12.25
1944	$	37	82.5	110	100.00%	$	37	0.8406	$	31	11.96
1943	$	-	83.5	111	100.00%	$	-	0.8443	$	-	11.68
1942	$	19	84.5	113	100.00%	$	19	0.8515	$	17	11.14
1941	$	58	85.5	114	100.00%	$	58	0.8550	$	49	10.88
1940	$	250	86.5	115	100.00%	$	250	0.8584	$	215	10.62
1939	$	286	87.5	117	100.00%	$	286	0.8650	$	247	10.13

1938	$ 179	88.5	118	100.00%	$ 179	0.8682	$ 155	9.89
1937	$ 223	89.5	119	100.00%	$ 223	0.8714	$ 195	9.65
1936	$ 101	90.5	121	100.00%	$ 101	0.8775	$ 88	9.19
1935	$ 533	91.5	122	100.00%	$ 533	0.8804	$ 469	8.97
1934	$ 124	92.5	123	100.00%	$ 124	0.8833	$ 109	8.75
1933	$ 55	93.5	125	100.00%	$ 55	0.8890	$ 49	8.33
1932	$ 39	94.5	126	100.00%	$ 39	0.8918	$ 35	8.12
1931	$ 10,678	95.5	127	100.00%	$ 10,678	0.8945	$ 9,551	7.91
1930	$ 548	96.5	129	100.00%	$ 548	0.8999	$ 493	7.51
1929	$ 410	97.5	130	100.00%	$ 410	0.9026	$ 370	7.31
1928	$ -	98.5	131	100.00%	$ -	0.9052	$ -	7.11
1927	$ -	99.5	133	100.00%	$ -	0.9104	$ -	6.72
1926	$ -	100.5	134	100.00%	$ -	0.9130	$ -	6.53
1925	$ -	101.5	135	100.00%	$ -	0.9156	$ -	6.33
1924	$ -	102.5	137	100.00%	$ -	0.9207	$ -	5.95
1923	$ -	103.5	138	100.00%	$ -	0.9233	$ -	5.75
1922	$ -	104.5	139	100.00%	$ -	0.9259	$ -	5.56
1921	$ -	105.5	141	100.00%	$ -	0.9310	$ -	5.18
1920	$ -	106.5	142	100.00%	$ -	0.9336	$ -	4.98
1919	$ -	107.5	143	100.00%	$ -	0.9362	$ -	4.79
1918	$ -	108.5	145	100.00%	$ -	0.9413	$ -	4.40
1917	$ -	109.5	146	100.00%	$ -	0.9439	$ -	4.21
1916	$ -	110.5	147	100.00%	$ -	0.9465	$ -	4.01
1915	$ -	111.5	149	100.00%	$ -	0.9516	$ -	3.63
1914	$ -	112.5	150	100.00%	$ -	0.9541	$ -	3.44
1913	$ -	113.5	151	100.00%	$ -	0.9566	$ -	3.26
1912	$ -	114.5	153	100.00%	$ -	0.9616	$ -	2.88
1911	$ -	115.5	154	100.00%	$ -	0.9641	$ -	2.69
1910	$ -	116.5	155	100.00%	$ -	0.9665	$ -	2.51
1909	$ -	117.5	157	100.00%	$ -	0.9714	$ -	2.15
1908	$ -	118.5	158	100.00%	$ -	0.9737	$ -	1.97
1907	$ -	119.5	159	100.00%	$ -	0.9761	$ -	1.79
1906	$ -	120.5	161	100.00%	$ -	0.9807	$ -	1.45
1905	$ -	121.5	162	100.00%	$ -	0.9830	$ -	1.28
1904	$ 222	122.5	163	100.00%	$ 222	0.9853	$ 219	1.10
1903	$ 298	123.5	165	100.00%	$ 298	0.9896	$ 295	0.78
1902	$ -	124.5	166	100.00%	$ -	0.9917	$ -	0.62
1901	$ -	125.5	167	100.00%	$ -	0.9936	$ -	0.48
1900	$ -	126.5	169	100.00%	$ -	1.0000	$ -	0.00
1899	$ -	127.5	170	100.00%	$ -	1.0000	$ -	0.00
1898	$ -	128.5	171	100.00%	$ -	1.0000	$ -	0.00
1897	$ -	129.5	173	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	174	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	175	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	177	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	178	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	179	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	181	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	182	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	183	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	185	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	186	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	187	100.00%	$ -	1.0000	$ -	0.00

1885	$ -	141.5	189	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	190	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	191	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	193	100.00%	$ -	1.0000	$ -	0.00
Total	$ 3,374,004				$ 3,374,004		$ 1,280,333	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 1,280,333	
Average Remaining Life		46.54
Theoretical Reserve %	37.95%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37500**
Plant Account **STRUCTURES AND IMPROVEMENTS**

Survivor Curve O1
Average Service Life 70
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 758,949	0.5	1	100.00%	$ 758,949	0.0050	$ 3,795	69.65
2025	$ 171,996	1.5	2	100.00%	$ 171,996	0.0100	$ 1,720	69.30
2024	$ 743,219	2.5	4	100.00%	$ 743,219	0.0200	$ 14,864	68.60
2023	$ 85,693	3.5	5	100.00%	$ 85,693	0.0250	$ 2,142	68.25
2022	$ 36,973	4.5	6	100.00%	$ 36,973	0.0300	$ 1,109	67.90
2021	$ 3,293	5.5	8	100.00%	$ 3,293	0.0400	$ 132	67.20
2020	$ 64,239	6.5	9	100.00%	$ 64,239	0.0450	$ 2,891	66.85
2019	$ 739,627	7.5	11	100.00%	$ 739,627	0.0550	$ 40,680	66.15
2018	$ 150,878	8.5	12	100.00%	$ 150,878	0.0600	$ 9,053	65.80
2017	$ 120,822	9.5	14	100.00%	$ 120,822	0.0700	$ 8,458	65.10
2016	$ 24,794	10.5	15	100.00%	$ 24,794	0.0750	$ 1,860	64.75
2015	$ 14,050	11.5	16	100.00%	$ 14,050	0.0800	$ 1,124	64.40
2014	$ 1,340,293	12.5	18	100.00%	$ 1,340,293	0.0900	$ 120,626	63.70
2013	$ 103,922	13.5	19	100.00%	$ 103,922	0.0950	$ 9,873	63.35
2012	$ 17,221	14.5	21	100.00%	$ 17,221	0.1050	$ 1,808	62.65
2011	$ 30,830	15.5	22	100.00%	$ 30,830	0.1100	$ 3,391	62.30
2010	$ 2,024	16.5	24	100.00%	$ 2,024	0.1200	$ 243	61.60
2009	$ 6,512	17.5	25	100.00%	$ 6,512	0.1250	$ 814	61.25
2008	$ 24,939	18.5	26	100.00%	$ 24,939	0.1300	$ 3,242	60.90
2007	$ 107,366	19.5	28	100.00%	$ 107,366	0.1400	$ 15,031	60.20
2006	$ 23,716	20.5	29	100.00%	$ 23,716	0.1450	$ 3,439	59.85
2005	$ 15,158	21.5	31	100.00%	$ 15,158	0.1550	$ 2,349	59.15
2004	$ 31,980	22.5	32	100.00%	$ 31,980	0.1600	$ 5,117	58.80
2003	$ 46,753	23.5	34	100.00%	$ 46,753	0.1700	$ 7,948	58.10
2002	$ 80,967	24.5	35	100.00%	$ 80,967	0.1750	$ 14,169	57.75
2001	$ 62,098	25.5	36	100.00%	$ 62,098	0.1800	$ 11,178	57.40
2000	$ 44,054	26.5	38	100.00%	$ 44,054	0.1900	$ 8,370	56.70
1999	$ 51,758	27.5	39	100.00%	$ 51,758	0.1950	$ 10,093	56.35
1998	$ 127,721	28.5	41	100.00%	$ 127,721	0.2050	$ 26,183	55.65
1997	$ 108,944	29.5	42	100.00%	$ 108,944	0.2100	$ 22,878	55.30
1996	$ 95,089	30.5	44	100.00%	$ 95,089	0.2200	$ 20,920	54.60

1995	$ 29,146	31.5	45	100.00%	$ 29,146	0.2250	$ 6,558	54.25
1994	$ 32,324	32.5	46	100.00%	$ 32,324	0.2300	$ 7,435	53.90
1993	$ 18,609	33.5	48	100.00%	$ 18,609	0.2400	$ 4,466	53.20
1992	$ -	34.5	49	100.00%	$ -	0.2450	$ -	52.85
1991	$ 5,120	35.5	51	100.00%	$ 5,120	0.2550	$ 1,306	52.15
1990	$ 19,711	36.5	52	100.00%	$ 19,711	0.2600	$ 5,125	51.80
1989	$ 41,624	37.5	54	100.00%	$ 41,624	0.2700	$ 11,238	51.10
1988	$ 13,244	38.5	55	100.00%	$ 13,244	0.2750	$ 3,642	50.75
1987	$ 33,574	39.5	56	100.00%	$ 33,574	0.2800	$ 9,401	50.40
1986	$ 15,835	40.5	58	100.00%	$ 15,835	0.2900	$ 4,592	49.70
1985	$ 69,915	41.5	59	100.00%	$ 69,915	0.2950	$ 20,625	49.35
1984	$ 114,266	42.5	61	100.00%	$ 114,266	0.3050	$ 34,851	48.65
1983	$ 28,862	43.5	62	100.00%	$ 28,862	0.3100	$ 8,947	48.30
1982	$ 59,755	44.5	64	100.00%	$ 59,755	0.3200	$ 19,122	47.60
1981	$ 70,113	45.5	65	100.00%	$ 70,113	0.3250	$ 22,787	47.25
1980	$ 10,177	46.5	66	100.00%	$ 10,177	0.3300	$ 3,358	46.90
1979	$ 6,025	47.5	68	100.00%	$ 6,025	0.3400	$ 2,048	46.20
1978	$ 18,739	48.5	69	100.00%	$ 18,739	0.3450	$ 6,465	45.85
1977	$ 9,842	49.5	71	100.00%	$ 9,842	0.3550	$ 3,494	45.15
1976	$ 4,924	50.5	72	100.00%	$ 4,924	0.3600	$ 1,773	44.80
1975	$ 91,660	51.5	74	100.00%	$ 91,660	0.3700	$ 33,914	44.10
1974	$ 33,094	52.5	75	100.00%	$ 33,094	0.3750	$ 12,410	43.75
1973	$ 55,736	53.5	76	100.00%	$ 55,736	0.3800	$ 21,180	43.40
1972	$ 16,615	54.5	78	100.00%	$ 16,615	0.3900	$ 6,480	42.70
1971	$ 55,787	55.5	79	100.00%	$ 55,787	0.3950	$ 22,036	42.35
1970	$ 130,316	56.5	81	100.00%	$ 130,316	0.4050	$ 52,778	41.65
1969	$ 45,448	57.5	82	100.00%	$ 45,448	0.4100	$ 18,634	41.30
1968	$ 44,275	58.5	84	100.00%	$ 44,275	0.4200	$ 18,595	40.60
1967	$ 54,678	59.5	85	100.00%	$ 54,678	0.4250	$ 23,238	40.25
1966	$ 25,021	60.5	86	100.00%	$ 25,021	0.4300	$ 10,759	39.90
1965	$ 43,822	61.5	88	100.00%	$ 43,822	0.4400	$ 19,281	39.20
1964	$ 38,738	62.5	89	100.00%	$ 38,738	0.4450	$ 17,238	38.85
1963	$ 78,000	63.5	91	100.00%	$ 78,000	0.4550	$ 35,490	38.15
1962	$ 74,248	64.5	92	100.00%	$ 74,248	0.4600	$ 34,154	37.80
1961	$ 48,265	65.5	94	100.00%	$ 48,265	0.4700	$ 22,685	37.10
1960	$ 42,256	66.5	95	100.00%	$ 42,256	0.4750	$ 20,072	36.75
1959	$ 36,478	67.5	96	100.00%	$ 36,478	0.4800	$ 17,510	36.40
1958	$ 20,327	68.5	98	100.00%	$ 20,327	0.4900	$ 9,960	35.70
1957	$ 84,152	69.5	99	100.00%	$ 84,152	0.4950	$ 41,655	35.35
1956	$ 39,160	70.5	101	100.00%	$ 39,160	0.5050	$ 19,776	34.65
1955	$ 22,449	71.5	102	100.00%	$ 22,449	0.5100	$ 11,449	34.30
1954	$ 82,748	72.5	104	100.00%	$ 82,748	0.5200	$ 43,029	33.60
1953	$ 65,775	73.5	105	100.00%	$ 65,775	0.5250	$ 34,532	33.25
1952	$ 23,329	74.5	106	100.00%	$ 23,329	0.5300	$ 12,364	32.90
1951	$ 117,566	75.5	108	100.00%	$ 117,566	0.5400	$ 63,486	32.20
1950	$ 336,891	76.5	109	100.00%	$ 336,891	0.5450	$ 183,606	31.85
1949	$ 156,817	77.5	111	100.00%	$ 156,817	0.5550	$ 87,034	31.15
1948	$ 18,368	78.5	112	100.00%	$ 18,368	0.5600	$ 10,286	30.80
1947	$ 1,626	79.5	114	100.00%	$ 1,626	0.5700	$ 927	30.10

1946	$	24,242	80.5	115	100.00%	$	24,242	0.5750	$	13,939	29.75
1945	$	7,400	81.5	116	100.00%	$	7,400	0.5800	$	4,292	29.40
1944	$	480	82.5	118	100.00%	$	480	0.5900	$	283	28.70
1943	$	3,799	83.5	119	100.00%	$	3,799	0.5950	$	2,260	28.35
1942	$	1,322	84.5	121	100.00%	$	1,322	0.6050	$	800	27.65
1941	$	1,498	85.5	122	100.00%	$	1,498	0.6100	$	914	27.30
1940	$	-	86.5	124	100.00%	$	-	0.6200	$	-	26.60
1939	$	941	87.5	125	100.00%	$	941	0.6250	$	588	26.25
1938	$	33	88.5	126	100.00%	$	33	0.6300	$	21	25.90
1937	$	4,519	89.5	128	100.00%	$	4,519	0.6400	$	2,892	25.20
1936	$	1,080	90.5	129	100.00%	$	1,080	0.6450	$	697	24.85
1935	$	-	91.5	131	100.00%	$	-	0.6550	$	-	24.15
1934	$	599	92.5	132	100.00%	$	599	0.6600	$	395	23.80
1933	$	5,693	93.5	134	100.00%	$	5,693	0.6700	$	3,815	23.10
1932	$	691	94.5	135	100.00%	$	691	0.6750	$	466	22.75
1931	$	887	95.5	136	100.00%	$	887	0.6800	$	603	22.40
1930	$	6,132	96.5	138	100.00%	$	6,132	0.6900	$	4,231	21.70
1929	$	1,787	97.5	139	100.00%	$	1,787	0.6950	$	1,242	21.35
1928	$	983	98.5	141	100.00%	$	983	0.7050	$	693	20.65
1927	$	27,707	99.5	142	100.00%	$	27,707	0.7100	$	19,672	20.30
1926	$	1,438	100.5	144	100.00%	$	1,438	0.7200	$	1,035	19.60
1925	$	9,741	101.5	145	100.00%	$	9,741	0.7250	$	7,063	19.25
1924	$	49,482	102.5	146	100.00%	$	49,482	0.7300	$	36,122	18.90
1923	$	680	103.5	148	100.00%	$	680	0.7400	$	503	18.20
1922	$	5,687	104.5	149	100.00%	$	5,687	0.7450	$	4,237	17.85
1921	$	17,408	105.5	151	100.00%	$	17,408	0.7550	$	13,143	17.15
1920	$	2,532	106.5	152	100.00%	$	2,532	0.7600	$	1,925	16.80
1919	$	2,219	107.5	154	100.00%	$	2,219	0.7700	$	1,709	16.10
1918	$	4,744	108.5	155	100.00%	$	4,744	0.7750	$	3,677	15.75
1917	$	5,255	109.5	156	100.00%	$	5,255	0.7800	$	4,099	15.40
1916	$	122	110.5	158	100.00%	$	122	0.7900	$	96	14.70
1915	$	126	111.5	159	100.00%	$	126	0.7950	$	100	14.35
1914	$	47	112.5	161	100.00%	$	47	0.8050	$	38	13.65
1913	$	-	113.5	162	100.00%	$	-	0.8100	$	-	13.30
1912	$	357	114.5	164	100.00%	$	357	0.8200	$	293	12.60
1911	$	-	115.5	165	100.00%	$	-	0.8250	$	-	12.25
1910	$	4,543	116.5	166	100.00%	$	4,543	0.8300	$	3,770	11.90
1909	$	770	117.5	168	100.00%	$	770	0.8400	$	647	11.20
1908	$	1,115	118.5	169	100.00%	$	1,115	0.8450	$	942	10.85
1907	$	-	119.5	171	100.00%	$	-	0.8550	$	-	10.15
1906	$	2,135	120.5	172	100.00%	$	2,135	0.8600	$	1,836	9.80
1905	$	1,322	121.5	174	100.00%	$	1,322	0.8700	$	1,150	9.10
1904	$	-	122.5	175	100.00%	$	-	0.8750	$	-	8.75
1903	$	-	123.5	176	100.00%	$	-	0.8800	$	-	8.40
1902	$	1,745	124.5	178	100.00%	$	1,745	0.8900	$	1,553	7.70
1901	$	435	125.5	179	100.00%	$	435	0.8950	$	390	7.35
1900	$	-	126.5	181	100.00%	$	-	0.9050	$	-	6.65
1899	$	-	127.5	182	100.00%	$	-	0.9100	$	-	6.30
1898	$	-	128.5	184	100.00%	$	-	0.9200	$	-	5.60

1897	$ -	129.5	185	100.00%	$ -	0.9250	$ -	5.25
1896	$ -	130.5	186	100.00%	$ -	0.9300	$ -	4.90
1895	$ -	131.5	188	100.00%	$ -	0.9400	$ -	4.20
1894	$ -	132.5	189	100.00%	$ -	0.9450	$ -	3.85
1893	$ -	133.5	191	100.00%	$ -	0.9550	$ -	3.15
1892	$ -	134.5	192	100.00%	$ -	0.9600	$ -	2.80
1891	$ -	135.5	194	100.00%	$ -	0.9700	$ -	2.10
1890	$ -	136.5	195	100.00%	$ -	0.9750	$ -	1.75
1889	$ -	137.5	196	100.00%	$ -	0.9800	$ -	1.40
1888	$ -	138.5	198	100.00%	$ -	0.9900	$ -	0.70
1887	$ -	139.5	199	100.00%	$ -	0.9950	$ -	0.35
1886	$ -	140.5	201	100.00%	$ -	0.0000	$ -	70.00
1885	$ -	141.5	202	100.00%	$ -	0.0000	$ -	70.00
1884	$ -	142.5	204	100.00%	$ -	0.0000	$ -	70.00
1883	$ -	143.5	205	100.00%	$ -	0.0000	$ -	70.00
1882	$ -	144.5	206	100.00%	$ -	0.0000	$ -	70.00
Total	$ 7,923,019				$ 7,923,019		$ 1,599,422	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage		$ 1,599,422
Average Remaining Life		55.87
Theoretical Reserve %	20.19%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37610**
Plant Account **MAINS - PRIMARILY STEEL**

Survivor Curve R2
Average Service Life 79
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 28,563,126	0.5	1	100.00%	$ 28,563,126	0.0091	$ 259,924	78.28
2025	$ 26,839,147	1.5	2	100.00%	$ 26,839,147	0.0181	$ 485,789	77.57
2024	$ 24,831,342	2.5	3	100.00%	$ 24,831,342	0.0271	$ 672,929	76.86
2023	$ 38,103,448	3.5	4	100.00%	$ 38,103,448	0.0361	$ 1,375,534	76.15
2022	$ 38,027,392	4.5	6	100.00%	$ 38,027,392	0.0540	$ 2,053,479	74.73
2021	$ 31,747,264	5.5	7	100.00%	$ 31,747,264	0.0629	$ 1,996,903	74.03
2020	$ 31,895,400	6.5	8	100.00%	$ 31,895,400	0.0717	$ 2,286,900	73.34
2019	$ 21,963,198	7.5	9	100.00%	$ 21,963,198	0.0806	$ 1,770,234	72.63
2018	$ 85,094,904	8.5	11	100.00%	$ 85,094,904	0.0982	$ 8,356,320	71.24
2017	$ 38,220,313	9.5	12	100.00%	$ 38,220,313	0.1070	$ 4,089,574	70.55
2016	$ 34,040,458	10.5	13	100.00%	$ 34,040,458	0.1157	$ 3,938,481	69.86
2015	$ 28,310,158	11.5	15	100.00%	$ 28,310,158	0.1331	$ 3,768,082	68.49
2014	$ 21,011,676	12.5	16	100.00%	$ 21,011,676	0.1417	$ 2,977,354	67.81
2013	$ 9,090,229	13.5	17	100.00%	$ 9,090,229	0.1503	$ 1,366,261	67.13
2012	$ 5,486,613	14.5	18	100.00%	$ 5,486,613	0.1589	$ 871,823	66.45
2011	$ 5,411,855	15.5	20	100.00%	$ 5,411,855	0.1760	$ 952,486	65.10
2010	$ 5,395,726	16.5	21	100.00%	$ 5,395,726	0.1845	$ 995,511	64.42
2009	$ 6,221,975	17.5	22	100.00%	$ 6,221,975	0.1930	$ 1,200,841	63.75
2008	$ 5,065,388	18.5	23	100.00%	$ 5,065,388	0.2014	$ 1,020,169	63.09
2007	$ 2,832,037	19.5	25	100.00%	$ 2,832,037	0.2182	$ 617,950	61.76
2006	$ 6,559,171	20.5	26	100.00%	$ 6,559,171	0.2265	$ 1,485,652	61.11
2005	$ 10,072,679	21.5	27	100.00%	$ 10,072,679	0.2348	$ 2,365,065	60.45
2004	$ 8,584,025	22.5	28	100.00%	$ 8,584,025	0.2430	$ 2,085,918	59.80
2003	$ 6,140,852	23.5	30	100.00%	$ 6,140,852	0.2595	$ 1,593,551	58.50
2002	$ 7,613,329	24.5	31	100.00%	$ 7,613,329	0.2676	$ 2,037,327	57.86
2001	$ 8,393,348	25.5	32	100.00%	$ 8,393,348	0.2757	$ 2,314,046	57.22
2000	$ 14,241,295	26.5	34	100.00%	$ 14,241,295	0.2919	$ 4,157,034	55.94
1999	$ 1,901,980	27.5	35	100.00%	$ 1,901,980	0.2999	$ 570,404	55.31
1998	$ 6,790,213	28.5	36	100.00%	$ 6,790,213	0.3079	$ 2,090,707	54.68
1997	$ 10,285,932	29.5	37	100.00%	$ 10,285,932	0.3158	$ 3,248,297	54.05
1996	$ 14,363,614	30.5	39	100.00%	$ 14,363,614	0.3316	$ 4,762,974	52.80
1995	$ 6,262,448	31.5	40	100.00%	$ 6,262,448	0.3394	$ 2,125,475	52.19
1994	$ 2,392,221	32.5	41	100.00%	$ 2,392,221	0.3472	$ 830,579	51.57
1993	$ 2,533,344	33.5	42	100.00%	$ 2,533,344	0.3549	$ 899,084	50.96
1992	$ 6,502,963	34.5	44	100.00%	$ 6,502,963	0.3703	$ 2,408,047	49.75

1991	$ 4,463,115	35.5	45	100.00%	$ 4,463,115	0.3780	$ 1,687,057	49.14
1990	$ 4,651,619	36.5	46	100.00%	$ 4,651,619	0.3855	$ 1,793,199	48.55
1989	$ 5,477,510	37.5	47	100.00%	$ 5,477,510	0.3931	$ 2,153,209	47.95
1988	$ 6,029,714	38.5	49	100.00%	$ 6,029,714	0.4081	$ 2,460,726	46.76
1987	$ 3,806,334	39.5	50	100.00%	$ 3,806,334	0.4155	$ 1,581,532	46.18
1986	$ 6,682,522	40.5	51	100.00%	$ 6,682,522	0.4229	$ 2,826,038	45.59
1985	$ 4,814,873	41.5	53	100.00%	$ 4,814,873	0.4375	$ 2,106,507	44.44
1984	$ 3,865,216	42.5	54	100.00%	$ 3,865,216	0.4447	$ 1,718,861	43.87
1983	$ 2,311,547	43.5	55	100.00%	$ 2,311,547	0.4520	$ 1,044,819	43.29
1982	$ 11,582,725	44.5	56	100.00%	$ 11,582,725	0.4591	$ 5,317,629	42.73
1981	$ 9,341,505	45.5	58	100.00%	$ 9,341,505	0.4733	$ 4,421,334	41.61
1980	$ 9,614,397	46.5	59	100.00%	$ 9,614,397	0.4803	$ 4,617,795	41.06
1979	$ 5,309,012	47.5	60	100.00%	$ 5,309,012	0.4873	$ 2,587,082	40.50
1978	$ 2,969,346	48.5	61	100.00%	$ 2,969,346	0.4942	$ 1,467,451	39.96
1977	$ 3,053,116	49.5	63	100.00%	$ 3,053,116	0.5080	$ 1,550,983	38.87
1976	$ 2,590,308	50.5	64	100.00%	$ 2,590,308	0.5147	$ 1,333,232	38.34
1975	$ 2,900,906	51.5	65	100.00%	$ 2,900,906	0.5215	$ 1,512,823	37.80
1974	$ 3,880,642	52.5	66	100.00%	$ 3,880,642	0.5282	$ 2,049,755	37.27
1973	$ 4,216,924	53.5	68	100.00%	$ 4,216,924	0.5414	$ 2,283,043	36.23
1972	$ 6,383,384	54.5	69	100.00%	$ 6,383,384	0.5479	$ 3,497,456	35.72
1971	$ 5,573,725	55.5	70	100.00%	$ 5,573,725	0.5544	$ 3,090,073	35.20
1970	$ 5,985,545	56.5	72	100.00%	$ 5,985,545	0.5673	$ 3,395,600	34.18
1969	$ 7,200,247	57.5	73	100.00%	$ 7,200,247	0.5736	$ 4,130,062	33.69
1968	$ 7,241,088	58.5	74	100.00%	$ 7,241,088	0.5799	$ 4,199,107	33.19
1967	$ 5,523,084	59.5	75	100.00%	$ 5,523,084	0.5861	$ 3,237,080	32.70
1966	$ 5,560,898	60.5	77	100.00%	$ 5,560,898	0.5984	$ 3,327,641	31.73
1965	$ 5,289,207	61.5	78	100.00%	$ 5,289,207	0.6044	$ 3,196,796	31.25
1964	$ 5,549,857	62.5	79	100.00%	$ 5,549,857	0.6105	$ 3,388,188	30.77
1963	$ 4,369,725	63.5	80	100.00%	$ 4,369,725	0.6164	$ 2,693,499	30.30
1962	$ 2,942,260	64.5	82	100.00%	$ 2,942,260	0.6282	$ 1,848,328	29.37
1961	$ 3,004,293	65.5	83	100.00%	$ 3,004,293	0.6339	$ 1,904,421	28.92
1960	$ 3,473,879	66.5	84	100.00%	$ 3,473,879	0.6397	$ 2,222,240	28.46
1959	$ 2,869,533	67.5	85	100.00%	$ 2,869,533	0.6453	$ 1,851,710	28.02
1958	$ 3,120,933	68.5	87	100.00%	$ 3,120,933	0.6565	$ 2,048,892	27.14
1957	$ 3,096,317	69.5	88	100.00%	$ 3,096,317	0.6620	$ 2,049,762	26.70
1956	$ 2,366,037	70.5	89	100.00%	$ 2,366,037	0.6674	$ 1,579,093	26.28
1955	$ 1,259,297	71.5	91	100.00%	$ 1,259,297	0.6781	$ 853,929	25.43
1954	$ 1,364,050	72.5	92	100.00%	$ 1,364,050	0.6834	$ 932,192	25.01
1953	$ 1,055,736	73.5	93	100.00%	$ 1,055,736	0.6886	$ 726,980	24.60
1952	$ 750,051	74.5	94	100.00%	$ 750,051	0.6938	$ 520,385	24.19
1951	$ 377,441	75.5	96	100.00%	$ 377,441	0.7039	$ 265,680	23.39
1950	$ 1,596,891	76.5	97	100.00%	$ 1,596,891	0.7088	$ 1,131,876	23.00
1949	$ 211,909	77.5	98	100.00%	$ 211,909	0.7137	$ 151,240	22.62
1948	$ 113,888	78.5	99	100.00%	$ 113,888	0.7186	$ 81,840	22.23
1947	$ 77,722	79.5	101	100.00%	$ 77,722	0.7281	$ 56,590	21.48
1946	$ 416,990	80.5	102	100.00%	$ 416,990	0.7328	$ 305,570	21.11
1945	$ 9,377	81.5	103	100.00%	$ 9,377	0.7374	$ 6,915	20.75
1944	$ 11,221	82.5	104	100.00%	$ 11,221	0.7419	$ 8,324	20.39
1943	$ 5,559	83.5	106	100.00%	$ 5,559	0.7508	$ 4,173	19.69
1942	$ 28,390	84.5	107	100.00%	$ 28,390	0.7552	$ 21,440	19.34
1941	$ 64,306	85.5	108	100.00%	$ 64,306	0.7595	$ 48,840	19.00
1940	$ 27,547	86.5	109	100.00%	$ 27,547	0.7638	$ 21,040	18.66
1939	$ 21,394	87.5	111	100.00%	$ 21,394	0.7721	$ 16,519	18.00

1938	$	9,778	88.5	112	100.00%	$	9,778	0.7762	$	7,590	17.68
1937	$	12,619	89.5	113	100.00%	$	12,619	0.7803	$	9,847	17.36
1936	$	21,978	90.5	115	100.00%	$	21,978	0.7882	$	17,323	16.73
1935	$	9,294	91.5	116	100.00%	$	9,294	0.7920	$	7,361	16.43
1934	$	11,320	92.5	117	100.00%	$	11,320	0.7958	$	9,008	16.13
1933	$	16,385	93.5	118	100.00%	$	16,385	0.7996	$	13,101	15.83
1932	$	69,650	94.5	120	100.00%	$	69,650	0.8070	$	56,208	15.25
1931	$	357,854	95.5	121	100.00%	$	357,854	0.8106	$	290,077	14.96
1930	$	363,093	96.5	122	100.00%	$	363,093	0.8142	$	295,630	14.68
1929	$	125,066	97.5	123	100.00%	$	125,066	0.8177	$	102,266	14.40
1928	$	136,881	98.5	125	100.00%	$	136,881	0.8247	$	112,886	13.85
1927	$	56,926	99.5	126	100.00%	$	56,926	0.8281	$	47,141	13.58
1926	$	287,899	100.5	127	100.00%	$	287,899	0.8314	$	239,359	13.32
1925	$	62,818	101.5	128	100.00%	$	62,818	0.8347	$	52,434	13.06
1924	$	137,720	102.5	130	100.00%	$	137,720	0.8413	$	115,864	12.54
1923	$	41,918	103.5	131	100.00%	$	41,918	0.8445	$	35,400	12.28
1922	$	25,265	104.5	132	100.00%	$	25,265	0.8477	$	21,417	12.03
1921	$	36,264	105.5	134	100.00%	$	36,264	0.8539	$	30,966	11.54
1920	$	4,709	106.5	135	100.00%	$	4,709	0.8570	$	4,036	11.30
1919	$	93	107.5	136	100.00%	$	93	0.8601	$	80	11.05
1918	$	3	108.5	137	100.00%	$	3	0.8632	$	3	10.81
1917	$	-	109.5	139	100.00%	$	-	0.8692	$	-	10.33
1916	$	14	110.5	140	100.00%	$	14	0.8722	$	12	10.10
1915	$	-	111.5	141	100.00%	$	-	0.8752	$	-	9.86
1914	$	326	112.5	142	100.00%	$	326	0.8782	$	286	9.62
1913	$	2,267	113.5	144	100.00%	$	2,267	0.8841	$	2,004	9.16
1912	$	-	114.5	145	100.00%	$	-	0.8870	$	-	8.93
1911	$	6	115.5	146	100.00%	$	6	0.8899	$	5	8.70
1910	$	2,877	116.5	147	100.00%	$	2,877	0.8928	$	2,569	8.47
1909	$	434	117.5	149	100.00%	$	434	0.8987	$	390	8.00
1908	$	21,094	118.5	150	100.00%	$	21,094	0.9016	$	19,018	7.77
1907	$	10,487	119.5	151	100.00%	$	10,487	0.9045	$	9,485	7.54
1906	$	4,139	120.5	153	100.00%	$	4,139	0.9103	$	3,768	7.09
1905	$	1,551	121.5	154	100.00%	$	1,551	0.9132	$	1,416	6.86
1904	$	335	122.5	155	100.00%	$	335	0.9161	$	307	6.63
1903	$	515	123.5	156	100.00%	$	515	0.9190	$	473	6.40
1902	$	-	124.5	158	100.00%	$	-	0.9248	$	-	5.94
1901	$	1,996	125.5	159	100.00%	$	1,996	0.9277	$	1,852	5.71
1900	$	-	126.5	160	100.00%	$	-	0.9305	$	-	5.49
1899	$	-	127.5	161	100.00%	$	-	0.9334	$	-	5.26
1898	$	-	128.5	163	100.00%	$	-	0.9391	$	-	4.81
1897	$	-	129.5	164	100.00%	$	-	0.9420	$	-	4.58
1896	$	-	130.5	165	100.00%	$	-	0.9448	$	-	4.36
1895	$	-	131.5	166	100.00%	$	-	0.9476	$	-	4.14
1894	$	-	132.5	168	100.00%	$	-	0.9532	$	-	3.70
1893	$	-	133.5	169	100.00%	$	-	0.9559	$	-	3.48
1892	$	-	134.5	170	100.00%	$	-	0.9587	$	-	3.26
1891	$	-	135.5	172	100.00%	$	-	0.9641	$	-	2.84
1890	$	-	136.5	173	100.00%	$	-	0.9668	$	-	2.62
1889	$	-	137.5	174	100.00%	$	-	0.9695	$	-	2.41
1888	$	-	138.5	175	100.00%	$	-	0.9722	$	-	2.20
1887	$	-	139.5	177	100.00%	$	-	0.9774	$	-	1.79
1886	$	-	140.5	178	100.00%	$	-	0.9800	$	-	1.58

1885	$ -	141.5	179	100.00%	$ -	0.9825	$ -	1.38
1884	$ -	142.5	180	100.00%	$ -	0.9851	$ -	1.18
1883	$ -	143.5	182	100.00%	$ -	0.9900	$ -	0.79
1882	$ -	144.5	183	100.00%	$ -	0.9923	$ -	0.61
Total	$787,125,750				$787,125,750		$172,866,842	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$172,866,842	
Average Remaining Life		61.65
Theoretical Reserve %	21.96%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37620**
Plant Account **MAINS - CAST IRON**

Survivor Curve R1
Average Service Life 65
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0074	$ -	64.52
2025	$ 30,688	1.5	2	100.00%	$ 30,688	0.0148	$ 454	64.04
2024	$ -	2.5	4	100.00%	$ -	0.0295	$ -	63.08
2023	$ -	3.5	5	100.00%	$ -	0.0369	$ -	62.60
2022	$ -	4.5	7	100.00%	$ -	0.0515	$ -	61.65
2021	$ -	5.5	8	100.00%	$ -	0.0587	$ -	61.18
2020	$ -	6.5	10	100.00%	$ -	0.0732	$ -	60.24
2019	$ -	7.5	12	100.00%	$ -	0.0876	$ -	59.31
2018	$ -	8.5	13	100.00%	$ -	0.0947	$ -	58.84
2017	$ -	9.5	15	100.00%	$ -	0.1090	$ -	57.92
2016	$ -	10.5	16	100.00%	$ -	0.1161	$ -	57.45
2015	$ -	11.5	18	100.00%	$ -	0.1302	$ -	56.54
2014	$ -	12.5	19	100.00%	$ -	0.1373	$ -	56.08
2013	$ -	13.5	21	100.00%	$ -	0.1513	$ -	55.17
2012	$ -	14.5	22	100.00%	$ -	0.1583	$ -	54.71
2011	$ -	15.5	24	100.00%	$ -	0.1722	$ -	53.81
2010	$ -	16.5	25	100.00%	$ -	0.1792	$ -	53.35
2009	$ -	17.5	27	100.00%	$ -	0.1930	$ -	52.46
2008	$ -	18.5	28	100.00%	$ -	0.1999	$ -	52.01
2007	$ -	19.5	30	100.00%	$ -	0.2136	$ -	51.12
2006	$ -	20.5	32	100.00%	$ -	0.2273	$ -	50.23
2005	$ -	21.5	33	100.00%	$ -	0.2341	$ -	49.78
2004	$ -	22.5	35	100.00%	$ -	0.2477	$ -	48.90
2003	$ -	23.5	36	100.00%	$ -	0.2545	$ -	48.46
2002	$ -	24.5	38	100.00%	$ -	0.2680	$ -	47.58
2001	$ -	25.5	39	100.00%	$ -	0.2747	$ -	47.14
2000	$ -	26.5	41	100.00%	$ -	0.2881	$ -	46.27
1999	$ -	27.5	42	100.00%	$ -	0.2947	$ -	45.84
1998	$ -	28.5	44	100.00%	$ -	0.3080	$ -	44.98
1997	$ -	29.5	45	100.00%	$ -	0.3146	$ -	44.55
1996	$ -	30.5	47	100.00%	$ -	0.3278	$ -	43.69
1995	$ -	31.5	48	100.00%	$ -	0.3343	$ -	43.27
1994	$ -	32.5	50	100.00%	$ -	0.3473	$ -	42.43
1993	$ -	33.5	52	100.00%	$ -	0.3602	$ -	41.59

1992	$ -	34.5	53	100.00%	$ -	0.3666	$ -	41.17
1991	$ -	35.5	55	100.00%	$ -	0.3794	$ -	40.34
1990	$ -	36.5	56	100.00%	$ -	0.3857	$ -	39.93
1989	$ -	37.5	58	100.00%	$ -	0.3983	$ -	39.11
1988	$ -	38.5	59	100.00%	$ -	0.4046	$ -	38.70
1987	$ -	39.5	61	100.00%	$ -	0.4170	$ -	37.90
1986	$ -	40.5	62	100.00%	$ -	0.4232	$ -	37.49
1985	$ -	41.5	64	100.00%	$ -	0.4354	$ -	36.70
1984	$ -	42.5	65	100.00%	$ -	0.4415	$ -	36.30
1983	$ -	43.5	67	100.00%	$ -	0.4535	$ -	35.52
1982	$ -	44.5	68	100.00%	$ -	0.4595	$ -	35.13
1981	$ -	45.5	70	100.00%	$ -	0.4714	$ -	34.36
1980	$ -	46.5	72	100.00%	$ -	0.4831	$ -	33.60
1979	$ -	47.5	73	100.00%	$ -	0.4889	$ -	33.22
1978	$ -	48.5	75	100.00%	$ -	0.5004	$ -	32.47
1977	$ -	49.5	76	100.00%	$ -	0.5061	$ -	32.10
1976	$ -	50.5	78	100.00%	$ -	0.5174	$ -	31.37
1975	$ -	51.5	79	100.00%	$ -	0.5231	$ -	31.00
1974	$ -	52.5	81	100.00%	$ -	0.5342	$ -	30.28
1973	$ -	53.5	82	100.00%	$ -	0.5397	$ -	29.92
1972	$ -	54.5	84	100.00%	$ -	0.5506	$ -	29.21
1971	$ -	55.5	85	100.00%	$ -	0.5560	$ -	28.86
1970	$ -	56.5	87	100.00%	$ -	0.5667	$ -	28.16
1969	$ -	57.5	88	100.00%	$ -	0.5719	$ -	27.83
1968	$ 316	58.5	90	100.00%	$ 316	0.5824	$ 184	27.14
1967	$ -	59.5	92	100.00%	$ -	0.5928	$ -	26.47
1966	$ -	60.5	93	100.00%	$ -	0.5979	$ -	26.14
1965	$ -	61.5	95	100.00%	$ -	0.6080	$ -	25.48
1964	$ -	62.5	96	100.00%	$ -	0.6130	$ -	25.16
1963	$ -	63.5	98	100.00%	$ -	0.6230	$ -	24.51
1962	$ 3,625	64.5	99	100.00%	$ 3,625	0.6279	$ 2,276	24.19
1961	$ -	65.5	101	100.00%	$ -	0.6376	$ -	23.56
1960	$ 5,230	66.5	102	100.00%	$ 5,230	0.6424	$ 3,360	23.24
1959	$ 34,438	67.5	104	100.00%	$ 34,438	0.6519	$ 22,450	22.63
1958	$ 12,730	68.5	105	100.00%	$ 12,730	0.6566	$ 8,358	22.32
1957	$ 31,202	69.5	107	100.00%	$ 31,202	0.6659	$ 20,778	21.72
1956	$ 22,722	70.5	108	100.00%	$ 22,722	0.6706	$ 15,238	21.41
1955	$ 45,943	71.5	110	100.00%	$ 45,943	0.6797	$ 31,228	20.82
1954	$ 23,733	72.5	112	100.00%	$ 23,733	0.6887	$ 16,345	20.23
1953	$ 13,919	73.5	113	100.00%	$ 13,919	0.6931	$ 9,647	19.95
1952	$ 105,994	74.5	115	100.00%	$ 105,994	0.7019	$ 74,397	19.38
1951	$ 14,465	75.5	116	100.00%	$ 14,465	0.7063	$ 10,216	19.09
1950	$ 9,771	76.5	118	100.00%	$ 9,771	0.7149	$ 6,985	18.53
1949	$ 14,981	77.5	119	100.00%	$ 14,981	0.7192	$ 10,775	18.25
1948	$ 13,944	78.5	121	100.00%	$ 13,944	0.7276	$ 10,146	17.71
1947	$ 4,534	79.5	122	100.00%	$ 4,534	0.7318	$ 3,318	17.43
1946	$ 3,466	80.5	124	100.00%	$ 3,466	0.7401	$ 2,566	16.89
1945	$ 233	81.5	125	100.00%	$ 233	0.7442	$ 174	16.63
1944	$ 2,021	82.5	127	100.00%	$ 2,021	0.7523	$ 1,521	16.10
1943	$ 1,568	83.5	128	100.00%	$ 1,568	0.7563	$ 1,186	15.84
1942	$ 456	84.5	130	100.00%	$ 456	0.7642	$ 348	15.33
1941	$ 6,305	85.5	132	100.00%	$ 6,305	0.7720	$ 4,868	14.82

1940	$	3,443	86.5	133	100.00%	$	3,443	0.7759	$	2,672	14.57
1939	$	4,544	87.5	135	100.00%	$	4,544	0.7835	$	3,560	14.07
1938	$	1,013	88.5	136	100.00%	$	1,013	0.7873	$	798	13.83
1937	$	1,507	89.5	138	100.00%	$	1,507	0.7948	$	1,198	13.34
1936	$	2,220	90.5	139	100.00%	$	2,220	0.7985	$	1,773	13.10
1935	$	1,405	91.5	141	100.00%	$	1,405	0.8058	$	1,132	12.62
1934	$	201	92.5	142	100.00%	$	201	0.8094	$	163	12.39
1933	$	94	93.5	144	100.00%	$	94	0.8166	$	77	11.92
1932	$	1,643	94.5	145	100.00%	$	1,643	0.8202	$	1,348	11.69
1931	$	3,415	95.5	147	100.00%	$	3,415	0.8272	$	2,825	11.23
1930	$	11,104	96.5	148	100.00%	$	11,104	0.8307	$	9,224	11.00
1929	$	22,641	97.5	150	100.00%	$	22,641	0.8376	$	18,964	10.56
1928	$	14,711	98.5	152	100.00%	$	14,711	0.8443	$	12,421	10.12
1927	$	19,332	99.5	153	100.00%	$	19,332	0.8477	$	16,388	9.90
1926	$	16,016	100.5	155	100.00%	$	16,016	0.8543	$	13,682	9.47
1925	$	7,038	101.5	156	100.00%	$	7,038	0.8576	$	6,036	9.26
1924	$	36,316	102.5	158	100.00%	$	36,316	0.8641	$	31,381	8.83
1923	$	8,233	103.5	159	100.00%	$	8,233	0.8674	$	7,141	8.62
1922	$	33,123	104.5	161	100.00%	$	33,123	0.8737	$	28,940	8.21
1921	$	2,271	105.5	162	100.00%	$	2,271	0.8769	$	1,991	8.00
1920	$	5,437	106.5	164	100.00%	$	5,437	0.8831	$	4,802	7.60
1919	$	5,743	107.5	165	100.00%	$	5,743	0.8862	$	5,090	7.40
1918	$	1,613	108.5	167	100.00%	$	1,613	0.8924	$	1,440	6.99
1917	$	2,303	109.5	168	100.00%	$	2,303	0.8954	$	2,062	6.80
1916	$	2,084	110.5	170	100.00%	$	2,084	0.9014	$	1,879	6.41
1915	$	3,725	111.5	172	100.00%	$	3,725	0.9074	$	3,380	6.02
1914	$	3,084	112.5	173	100.00%	$	3,084	0.9104	$	2,807	5.82
1913	$	871	113.5	175	100.00%	$	871	0.9163	$	798	5.44
1912	$	7,799	114.5	176	100.00%	$	7,799	0.9193	$	7,170	5.25
1911	$	16,381	115.5	178	100.00%	$	16,381	0.9252	$	15,155	4.86
1910	$	2,821	116.5	179	100.00%	$	2,821	0.9282	$	2,619	4.67
1909	$	1,516	117.5	181	100.00%	$	1,516	0.9342	$	1,416	4.28
1908	$	4,639	118.5	182	100.00%	$	4,639	0.9372	$	4,348	4.08
1907	$	1,672	119.5	184	100.00%	$	1,672	0.9435	$	1,578	3.67
1906	$	4,427	120.5	185	100.00%	$	4,427	0.9467	$	4,191	3.46
1905	$	990	121.5	187	100.00%	$	990	0.9533	$	944	3.04
1904	$	3,071	122.5	188	100.00%	$	3,071	0.9567	$	2,938	2.81
1903	$	1,489	123.5	190	100.00%	$	1,489	0.9634	$	1,435	2.38
1902	$	1,876	124.5	192	100.00%	$	1,876	0.9701	$	1,820	1.94
1901	$	665	125.5	193	100.00%	$	665	0.9735	$	648	1.72
1900	$	-	126.5	195	100.00%	$	-	0.9801	$	-	1.29
1899	$	-	127.5	196	100.00%	$	-	0.9833	$	-	1.09
1898	$	-	128.5	198	100.00%	$	-	0.9896	$	-	0.68
1897	$	-	129.5	199	100.00%	$	-	0.9925	$	-	0.49
1896	$	-	130.5	201	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	202	100.00%	$	-	1.0000	$	-	0.00
1894	$	-	132.5	204	100.00%	$	-	1.0000	$	-	0.00
1893	$	-	133.5	205	100.00%	$	-	1.0000	$	-	0.00
1892	$	-	134.5	207	100.00%	$	-	1.0000	$	-	0.00
1891	$	-	135.5	208	100.00%	$	-	1.0000	$	-	0.00
1890	$	-	136.5	210	100.00%	$	-	1.0000	$	-	0.00
1889	$	-	137.5	212	100.00%	$	-	1.0000	$	-	0.00

1888	$	-	138.5	213	100.00%	$	-	1.0000	$	-	0.00
1887	$	-	139.5	215	100.00%	$	-	1.0000	$	-	0.00
1886	$	-	140.5	216	100.00%	$	-	1.0000	$	-	0.00
1885	$	-	141.5	218	100.00%	$	-	1.0000	$	-	0.00
1884	$	-	142.5	219	100.00%	$	-	1.0000	$	-	0.00
1883	$	-	143.5	221	100.00%	$	-	1.0000	$	-	0.00
1882	$	-	144.5	222	100.00%	$	-	1.0000	$	-	0.00
Total	$	664,766				$	664,766		$	485,052	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage	$	485,052
Average Remaining Life		17.57
Theoretical Reserve %		72.97%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37630**
Plant Account **MAINS - PLASTIC**

Survivor Curve R3
Average Service Life 68
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 181,975,232	0.5	1	100.00%	$ 181,975,232	0.0098	$ 1,783,357	67.33
2025	$ 163,801,567	1.5	2	100.00%	$ 163,801,567	0.0197	$ 3,226,891	66.66
2024	$ 145,609,486	2.5	4	100.00%	$ 145,609,486	0.0393	$ 5,722,453	65.33
2023	$ 179,949,196	3.5	5	100.00%	$ 179,949,196	0.0491	$ 8,835,506	64.66
2022	$ 156,320,375	4.5	7	100.00%	$ 156,320,375	0.0686	$ 10,723,578	63.34
2021	$ 123,867,639	5.5	8	100.00%	$ 123,867,639	0.0784	$ 9,711,223	62.67
2020	$ 110,623,776	6.5	10	100.00%	$ 110,623,776	0.0978	$ 10,819,005	61.35
2019	$ 107,812,901	7.5	11	100.00%	$ 107,812,901	0.1075	$ 11,589,887	60.69
2018	$ 90,642,394	8.5	13	100.00%	$ 90,642,394	0.1269	$ 11,502,520	59.37
2017	$ 73,154,314	9.5	14	100.00%	$ 73,154,314	0.1365	$ 9,985,564	58.72
2016	$ 74,479,865	10.5	15	100.00%	$ 74,479,865	0.1461	$ 10,881,508	58.07
2015	$ 60,980,960	11.5	17	100.00%	$ 60,980,960	0.1653	$ 10,080,153	56.76
2014	$ 48,690,025	12.5	18	100.00%	$ 48,690,025	0.1748	$ 8,511,016	56.11
2013	$ 40,868,879	13.5	20	100.00%	$ 40,868,879	0.1938	$ 7,920,389	54.82
2012	$ 36,317,463	14.5	21	100.00%	$ 36,317,463	0.2033	$ 7,383,340	54.18
2011	$ 29,433,099	15.5	23	100.00%	$ 29,433,099	0.2221	$ 6,537,091	52.90
2010	$ 22,124,093	16.5	24	100.00%	$ 22,124,093	0.2315	$ 5,121,727	52.26
2009	$ 21,252,097	17.5	26	100.00%	$ 21,252,097	0.2501	$ 5,315,149	50.99
2008	$ 21,354,895	18.5	27	100.00%	$ 21,354,895	0.2594	$ 5,539,460	50.36
2007	$ 25,143,367	19.5	29	100.00%	$ 25,143,367	0.2779	$ 6,987,342	49.10
2006	$ 25,294,038	20.5	30	100.00%	$ 25,294,038	0.2871	$ 7,261,918	48.48
2005	$ 25,607,470	21.5	32	100.00%	$ 25,607,470	0.3053	$ 7,817,961	47.24
2004	$ 26,007,573	22.5	33	100.00%	$ 26,007,573	0.3144	$ 8,176,781	46.62
2003	$ 22,240,360	23.5	35	100.00%	$ 22,240,360	0.3324	$ 7,392,696	45.40
2002	$ 17,475,617	24.5	36	100.00%	$ 17,475,617	0.3413	$ 5,964,428	44.79
2001	$ 20,585,966	25.5	38	100.00%	$ 20,585,966	0.3591	$ 7,392,420	43.58
2000	$ 19,906,259	26.5	39	100.00%	$ 19,906,259	0.3679	$ 7,323,513	42.98
1999	$ 19,045,607	27.5	40	100.00%	$ 19,045,607	0.3767	$ 7,174,480	42.38
1998	$ 23,031,355	28.5	42	100.00%	$ 23,031,355	0.3942	$ 9,078,960	41.19
1997	$ 28,874,042	29.5	43	100.00%	$ 28,874,042	0.4028	$ 11,630,464	40.61
1996	$ 20,343,402	30.5	45	100.00%	$ 20,343,402	0.4200	$ 8,544,229	39.44
1995	$ 24,558,519	31.5	46	100.00%	$ 24,558,519	0.4285	$ 10,523,325	38.86
1994	$ 18,205,758	32.5	48	100.00%	$ 18,205,758	0.4454	$ 8,108,845	37.71

1993	$ 11,233,460	33.5	49	100.00%	$ 11,233,460	0.4538	$ 5,097,744	37.14
1992	$ 11,896,473	34.5	51	100.00%	$ 11,896,473	0.4704	$ 5,596,101	36.01
1991	$ 13,839,235	35.5	52	100.00%	$ 13,839,235	0.4786	$ 6,623,458	35.46
1990	$ 21,968,819	36.5	54	100.00%	$ 21,968,819	0.4949	$ 10,872,368	34.35
1989	$ 19,573,990	37.5	55	100.00%	$ 19,573,990	0.5029	$ 9,843,759	33.80
1988	$ 18,721,477	38.5	57	100.00%	$ 18,721,477	0.5189	$ 9,714,574	32.71
1987	$ 12,186,719	39.5	58	100.00%	$ 12,186,719	0.5268	$ 6,419,963	32.18
1986	$ 8,176,457	40.5	60	100.00%	$ 8,176,457	0.5425	$ 4,435,728	31.11
1985	$ 6,359,899	41.5	61	100.00%	$ 6,359,899	0.5503	$ 3,499,853	30.58
1984	$ 5,692,288	42.5	63	100.00%	$ 5,692,288	0.5656	$ 3,219,558	29.54
1983	$ 4,076,024	43.5	64	100.00%	$ 4,076,024	0.5732	$ 2,336,377	29.02
1982	$ 4,262,345	44.5	65	100.00%	$ 4,262,345	0.5807	$ 2,475,144	28.51
1981	$ 3,794,808	45.5	67	100.00%	$ 3,794,808	0.5956	$ 2,260,187	27.50
1980	$ 3,905,346	46.5	68	100.00%	$ 3,905,346	0.6029	$ 2,354,533	27.00
1979	$ 2,944,635	47.5	70	100.00%	$ 2,944,635	0.6174	$ 1,818,018	26.02
1978	$ 2,914,278	48.5	71	100.00%	$ 2,914,278	0.6245	$ 1,819,967	25.53
1977	$ 2,450,481	49.5	73	100.00%	$ 2,450,481	0.6387	$ 1,565,122	24.57
1976	$ 1,889,464	50.5	74	100.00%	$ 1,889,464	0.6456	$ 1,219,838	24.10
1975	$ 2,208,562	51.5	76	100.00%	$ 2,208,562	0.6593	$ 1,456,105	23.17
1974	$ 1,233,811	52.5	77	100.00%	$ 1,233,811	0.6661	$ 821,841	22.71
1973	$ 769,344	53.5	79	100.00%	$ 769,344	0.6793	$ 522,616	21.81
1972	$ 576,773	54.5	80	100.00%	$ 576,773	0.6858	$ 395,551	21.37
1971	$ 367,004	55.5	82	100.00%	$ 367,004	0.6986	$ 256,389	20.50
1970	$ 26,078	56.5	83	100.00%	$ 26,078	0.7049	$ 18,382	20.07
1969	$ 7,114	57.5	85	100.00%	$ 7,114	0.7172	$ 5,102	19.23
1968	$ 12,972	58.5	86	100.00%	$ 12,972	0.7233	$ 9,383	18.82
1967	$ 6,336	59.5	88	100.00%	$ 6,336	0.7351	$ 4,657	18.01
1966	$ -	60.5	89	100.00%	$ -	0.7409	$ -	17.62
1965	$ -	61.5	90	100.00%	$ -	0.7465	$ -	17.24
1964	$ -	62.5	92	100.00%	$ -	0.7576	$ -	16.48
1963	$ -	63.5	93	100.00%	$ -	0.7630	$ -	16.12
1962	$ -	64.5	95	100.00%	$ -	0.7736	$ -	15.40
1961	$ -	65.5	96	100.00%	$ -	0.7787	$ -	15.05
1960	$ -	66.5	98	100.00%	$ -	0.7887	$ -	14.37
1959	$ -	67.5	99	100.00%	$ -	0.7935	$ -	14.04
1958	$ -	68.5	101	100.00%	$ -	0.8029	$ -	13.40
1957	$ -	69.5	102	100.00%	$ -	0.8075	$ -	13.09
1956	$ -	70.5	104	100.00%	$ -	0.8163	$ -	12.49
1955	$ -	71.5	105	100.00%	$ -	0.8206	$ -	12.20
1954	$ -	72.5	107	100.00%	$ -	0.8288	$ -	11.64
1953	$ -	73.5	108	100.00%	$ -	0.8328	$ -	11.37
1952	$ -	74.5	110	100.00%	$ -	0.8406	$ -	10.84
1951	$ -	75.5	111	100.00%	$ -	0.8443	$ -	10.59
1950	$ -	76.5	113	100.00%	$ -	0.8515	$ -	10.10
1949	$ -	77.5	114	100.00%	$ -	0.8550	$ -	9.86
1948	$ -	78.5	115	100.00%	$ -	0.8584	$ -	9.63
1947	$ -	79.5	117	100.00%	$ -	0.8650	$ -	9.18
1946	$ -	80.5	118	100.00%	$ -	0.8682	$ -	8.96
1945	$ -	81.5	120	100.00%	$ -	0.8744	$ -	8.54
1944	$ -	82.5	121	100.00%	$ -	0.8775	$ -	8.33
1943	$ -	83.5	123	100.00%	$ -	0.8833	$ -	7.94

1942	$	-	84.5	124	100.00%	$	-	0.8862	$	-	7.74
1941	$	-	85.5	126	100.00%	$	-	0.8918	$	-	7.36
1940	$	-	86.5	127	100.00%	$	-	0.8945	$	-	7.17
1939	$	-	87.5	129	100.00%	$	-	0.8999	$	-	6.81
1938	$	-	88.5	130	100.00%	$	-	0.9026	$	-	6.62
1937	$	-	89.5	132	100.00%	$	-	0.9078	$	-	6.27
1936	$	-	90.5	133	100.00%	$	-	0.9104	$	-	6.09
1935	$	-	91.5	135	100.00%	$	-	0.9156	$	-	5.74
1934	$	-	92.5	136	100.00%	$	-	0.9182	$	-	5.56
1933	$	-	93.5	138	100.00%	$	-	0.9233	$	-	5.22
1932	$	-	94.5	139	100.00%	$	-	0.9259	$	-	5.04
1931	$	-	95.5	140	100.00%	$	-	0.9285	$	-	4.86
1930	$	-	96.5	142	100.00%	$	-	0.9336	$	-	4.52
1929	$	-	97.5	143	100.00%	$	-	0.9362	$	-	4.34
1928	$	-	98.5	145	100.00%	$	-	0.9413	$	-	3.99
1927	$	-	99.5	146	100.00%	$	-	0.9439	$	-	3.81
1926	$	-	100.5	148	100.00%	$	-	0.9490	$	-	3.47
1925	$	-	101.5	149	100.00%	$	-	0.9516	$	-	3.29
1924	$	-	102.5	151	100.00%	$	-	0.9566	$	-	2.95
1923	$	-	103.5	152	100.00%	$	-	0.9591	$	-	2.78
1922	$	-	104.5	154	100.00%	$	-	0.9641	$	-	2.44
1921	$	-	105.5	155	100.00%	$	-	0.9665	$	-	2.28
1920	$	-	106.5	157	100.00%	$	-	0.9714	$	-	1.94
1919	$	-	107.5	158	100.00%	$	-	0.9737	$	-	1.79
1918	$	-	108.5	160	100.00%	$	-	0.9784	$	-	1.47
1917	$	-	109.5	161	100.00%	$	-	0.9807	$	-	1.31
1916	$	-	110.5	163	100.00%	$	-	0.9853	$	-	1.00
1915	$	-	111.5	164	100.00%	$	-	0.9875	$	-	0.85
1914	$	-	112.5	165	100.00%	$	-	0.9896	$	-	0.71
1913	$	-	113.5	167	100.00%	$	-	0.9936	$	-	0.44
1912	$	-	114.5	168	100.00%	$	-	0.9950	$	-	0.34
1911	$	-	115.5	170	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	171	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	173	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	174	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	176	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	177	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	179	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	180	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	182	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	183	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	185	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	186	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	188	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	189	100.00%	$	-	1.0000	$	-	0.00
1897	$	-	129.5	190	100.00%	$	-	1.0000	$	-	0.00
1896	$	-	130.5	192	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	193	100.00%	$	-	1.0000	$	-	0.00
1894	$	-	132.5	195	100.00%	$	-	1.0000	$	-	0.00
1893	$	-	133.5	196	100.00%	$	-	1.0000	$	-	0.00
1892	$	-	134.5	198	100.00%	$	-	1.0000	$	-	0.00

1891	$ -	135.5	199	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	201	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	202	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	204	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	205	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	207	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	208	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	210	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	211	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	213	100.00%	$ -	1.0000	$ -	0.00
Total	$ 2,166,671,780				$ 2,166,671,780		$ 349,229,497	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 349,229,497	
Average Remaining Life		57.04
Theoretical Reserve %	16.12%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37650**
Plant Account **MAINS - PRIMARILY WROUGHT IRON**

Survivor Curve R1
Average Service Life 70
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0074	$ -	69.48
2025	$ 4,828	1.5	2	100.00%	$ 4,828	0.0148	$ 71	68.96
2024	$ -	2.5	4	100.00%	$ -	0.0295	$ -	67.94
2023	$ -	3.5	5	100.00%	$ -	0.0369	$ -	67.42
2022	$ -	4.5	6	100.00%	$ -	0.0442	$ -	66.91
2021	$ -	5.5	8	100.00%	$ -	0.0587	$ -	65.89
2020	$ -	6.5	9	100.00%	$ -	0.0660	$ -	65.38
2019	$ -	7.5	11	100.00%	$ -	0.0804	$ -	64.37
2018	$ -	8.5	12	100.00%	$ -	0.0876	$ -	63.87
2017	$ -	9.5	14	100.00%	$ -	0.1019	$ -	62.87
2016	$ -	10.5	15	100.00%	$ -	0.1090	$ -	62.37
2015	$ -	11.5	16	100.00%	$ -	0.1161	$ -	61.87
2014	$ -	12.5	18	100.00%	$ -	0.1302	$ -	60.89
2013	$ -	13.5	19	100.00%	$ -	0.1373	$ -	60.39
2012	$ -	14.5	21	100.00%	$ -	0.1513	$ -	59.41
2011	$ -	15.5	22	100.00%	$ -	0.1583	$ -	58.92
2010	$ -	16.5	24	100.00%	$ -	0.1722	$ -	57.95
2009	$ -	17.5	25	100.00%	$ -	0.1792	$ -	57.46
2008	$ -	18.5	26	100.00%	$ -	0.1861	$ -	56.97
2007	$ -	19.5	28	100.00%	$ -	0.1999	$ -	56.01
2006	$ -	20.5	29	100.00%	$ -	0.2068	$ -	55.52
2005	$ -	21.5	31	100.00%	$ -	0.2205	$ -	54.57
2004	$ -	22.5	32	100.00%	$ -	0.2273	$ -	54.09
2003	$ -	23.5	34	100.00%	$ -	0.2409	$ -	53.14
2002	$ -	24.5	35	100.00%	$ -	0.2477	$ -	52.66
2001	$ -	25.5	36	100.00%	$ -	0.2545	$ -	52.19
2000	$ -	26.5	38	100.00%	$ -	0.2680	$ -	51.24
1999	$ -	27.5	39	100.00%	$ -	0.2747	$ -	50.77
1998	$ -	28.5	41	100.00%	$ -	0.2881	$ -	49.83
1997	$ -	29.5	42	100.00%	$ -	0.2947	$ -	49.37
1996	$ -	30.5	44	100.00%	$ -	0.3080	$ -	48.44

1995	$	-	31.5	45	100.00%	$	-	0.3146	$	-	47.98
1994	$	-	32.5	46	100.00%	$	-	0.3212	$	-	47.52
1993	$	-	33.5	48	100.00%	$	-	0.3343	$	-	46.60
1992	$	-	34.5	49	100.00%	$	-	0.3408	$	-	46.14
1991	$	-	35.5	51	100.00%	$	-	0.3538	$	-	45.23
1990	$	-	36.5	52	100.00%	$	-	0.3602	$	-	44.79
1989	$	-	37.5	54	100.00%	$	-	0.3730	$	-	43.89
1988	$	-	38.5	55	100.00%	$	-	0.3794	$	-	43.44
1987	$	-	39.5	56	100.00%	$	-	0.3857	$	-	43.00
1986	$	-	40.5	58	100.00%	$	-	0.3983	$	-	42.12
1985	$	-	41.5	59	100.00%	$	-	0.4046	$	-	41.68
1984	$	-	42.5	61	100.00%	$	-	0.4170	$	-	40.81
1983	$	-	43.5	62	100.00%	$	-	0.4232	$	-	40.38
1982	$	-	44.5	64	100.00%	$	-	0.4354	$	-	39.52
1981	$	-	45.5	65	100.00%	$	-	0.4415	$	-	39.10
1980	$	-	46.5	66	100.00%	$	-	0.4475	$	-	38.68
1979	$	-	47.5	68	100.00%	$	-	0.4595	$	-	37.84
1978	$	-	48.5	69	100.00%	$	-	0.4655	$	-	37.42
1977	$	-	49.5	71	100.00%	$	-	0.4772	$	-	36.60
1976	$	-	50.5	72	100.00%	$	-	0.4831	$	-	36.18
1975	$	-	51.5	74	100.00%	$	-	0.4947	$	-	35.37
1974	$	-	52.5	75	100.00%	$	-	0.5004	$	-	34.97
1973	$	-	53.5	76	100.00%	$	-	0.5061	$	-	34.57
1972	$	-	54.5	78	100.00%	$	-	0.5174	$	-	33.78
1971	$	-	55.5	79	100.00%	$	-	0.5231	$	-	33.38
1970	$	-	56.5	81	100.00%	$	-	0.5342	$	-	32.61
1969	$	-	57.5	82	100.00%	$	-	0.5397	$	-	32.22
1968	$	-	58.5	84	100.00%	$	-	0.5506	$	-	31.46
1967	$	-	59.5	85	100.00%	$	-	0.5560	$	-	31.08
1966	$	-	60.5	86	100.00%	$	-	0.5613	$	-	30.71
1965	$	-	61.5	88	100.00%	$	-	0.5719	$	-	29.97
1964	$	-	62.5	89	100.00%	$	-	0.5772	$	-	29.60
1963	$	-	63.5	91	100.00%	$	-	0.5876	$	-	28.87
1962	$	-	64.5	92	100.00%	$	-	0.5928	$	-	28.50
1961	$	-	65.5	94	100.00%	$	-	0.6030	$	-	27.79
1960	$	-	66.5	95	100.00%	$	-	0.6080	$	-	27.44
1959	$	-	67.5	96	100.00%	$	-	0.6130	$	-	27.09
1958	$	-	68.5	98	100.00%	$	-	0.6230	$	-	26.39
1957	$	-	69.5	99	100.00%	$	-	0.6279	$	-	26.05
1956	$	-	70.5	101	100.00%	$	-	0.6376	$	-	25.37
1955	$	-	71.5	102	100.00%	$	-	0.6424	$	-	25.03
1954	$	-	72.5	104	100.00%	$	-	0.6519	$	-	24.37
1953	$	-	73.5	105	100.00%	$	-	0.6566	$	-	24.04
1952	$	-	74.5	106	100.00%	$	-	0.6613	$	-	23.71
1951	$	-	75.5	108	100.00%	$	-	0.6706	$	-	23.06
1950	$	-	76.5	109	100.00%	$	-	0.6751	$	-	22.74
1949	$	-	77.5	111	100.00%	$	-	0.6842	$	-	22.11
1948	$	-	78.5	112	100.00%	$	-	0.6887	$	-	21.79
1947	$	-	79.5	114	100.00%	$	-	0.6976	$	-	21.17

1946	$	-	80.5	115	100.00%	$	-	0.7019	$	-	20.87
1945	$	-	81.5	116	100.00%	$	-	0.7063	$	-	20.56
1944	$	-	82.5	118	100.00%	$	-	0.7149	$	-	19.96
1943	$	25	83.5	119	100.00%	$	25	0.7192	$	18	19.66
1942	$	-	84.5	121	100.00%	$	-	0.7276	$	-	19.07
1941	$	-	85.5	122	100.00%	$	-	0.7318	$	-	18.77
1940	$	30	86.5	124	100.00%	$	30	0.7401	$	22	18.19
1939	$	126	87.5	125	100.00%	$	126	0.7442	$	94	17.91
1938	$	-	88.5	126	100.00%	$	-	0.7482	$	-	17.63
1937	$	-	89.5	128	100.00%	$	-	0.7563	$	-	17.06
1936	$	-	90.5	129	100.00%	$	-	0.7602	$	-	16.79
1935	$	-	91.5	131	100.00%	$	-	0.7681	$	-	16.23
1934	$	-	92.5	132	100.00%	$	-	0.7720	$	-	15.96
1933	$	-	93.5	134	100.00%	$	-	0.7797	$	-	15.42
1932	$	-	94.5	135	100.00%	$	-	0.7835	$	-	15.16
1931	$	-	95.5	136	100.00%	$	-	0.7873	$	-	14.89
1930	$	-	96.5	138	100.00%	$	-	0.7948	$	-	14.36
1929	$	-	97.5	139	100.00%	$	-	0.7985	$	-	14.11
1928	$	52	98.5	141	100.00%	$	52	0.8058	$	42	13.59
1927	$	-	99.5	142	100.00%	$	-	0.8094	$	-	13.34
1926	$	-	100.5	144	100.00%	$	-	0.8166	$	-	12.84
1925	$	-	101.5	145	100.00%	$	-	0.8202	$	-	12.59
1924	$	43,150	102.5	146	100.00%	$	43,150	0.8237	$	35,543	12.34
1923	$	14,827	103.5	148	100.00%	$	14,827	0.8307	$	12,316	11.85
1922	$	14,231	104.5	149	100.00%	$	14,231	0.8341	$	11,870	11.61
1921	$	9,356	105.5	151	100.00%	$	9,356	0.8410	$	7,869	11.13
1920	$	2,322	106.5	152	100.00%	$	2,322	0.8443	$	1,961	10.90
1919	$	5,274	107.5	154	100.00%	$	5,274	0.8510	$	4,488	10.43
1918	$	4,098	108.5	155	100.00%	$	4,098	0.8543	$	3,501	10.20
1917	$	3,880	109.5	156	100.00%	$	3,880	0.8576	$	3,327	9.97
1916	$	19,757	110.5	158	100.00%	$	19,757	0.8641	$	17,072	9.51
1915	$	28,580	111.5	159	100.00%	$	28,580	0.8674	$	24,790	9.28
1914	$	52,718	112.5	161	100.00%	$	52,718	0.8737	$	46,060	8.84
1913	$	19,952	113.5	162	100.00%	$	19,952	0.8769	$	17,496	8.62
1912	$	15,375	114.5	164	100.00%	$	15,375	0.8831	$	13,578	8.18
1911	$	20,101	115.5	165	100.00%	$	20,101	0.8862	$	17,814	7.97
1910	$	8,993	116.5	166	100.00%	$	8,993	0.8893	$	7,997	7.75
1909	$	6,566	117.5	168	100.00%	$	6,566	0.8954	$	5,879	7.32
1908	$	6,471	118.5	169	100.00%	$	6,471	0.8984	$	5,813	7.11
1907	$	3,012	119.5	171	100.00%	$	3,012	0.9044	$	2,724	6.69
1906	$	5,140	120.5	172	100.00%	$	5,140	0.9074	$	4,664	6.48
1905	$	2,829	121.5	174	100.00%	$	2,829	0.9134	$	2,584	6.06
1904	$	8,043	122.5	175	100.00%	$	8,043	0.9163	$	7,370	5.86
1903	$	2,784	123.5	176	100.00%	$	2,784	0.9193	$	2,559	5.65
1902	$	858	124.5	178	100.00%	$	858	0.9252	$	794	5.24
1901	$	1,823	125.5	179	100.00%	$	1,823	0.9282	$	1,693	5.03
1900	$	-	126.5	181	100.00%	$	-	0.9342	$	-	4.61
1899	$	-	127.5	182	100.00%	$	-	0.9372	$	-	4.40
1898	$	-	128.5	184	100.00%	$	-	0.9435	$	-	3.96

1897	$ -	129.5	185	100.00%	$ -	0.9467	$ -	3.73
1896	$ -	130.5	186	100.00%	$ -	0.9499	$ -	3.51
1895	$ -	131.5	188	100.00%	$ -	0.9567	$ -	3.03
1894	$ -	132.5	189	100.00%	$ -	0.9601	$ -	2.79
1893	$ -	133.5	191	100.00%	$ -	0.9668	$ -	2.32
1892	$ -	134.5	192	100.00%	$ -	0.9701	$ -	2.09
1891	$ -	135.5	194	100.00%	$ -	0.9768	$ -	1.62
1890	$ -	136.5	195	100.00%	$ -	0.9801	$ -	1.39
1889	$ -	137.5	196	100.00%	$ -	0.9833	$ -	1.17
1888	$ -	138.5	198	100.00%	$ -	0.9896	$ -	0.73
1887	$ -	139.5	199	100.00%	$ -	0.9925	$ -	0.52
1886	$ -	140.5	201	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	202	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	204	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	205	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	206	100.00%	$ -	1.0000	$ -	0.00
Total	$ 305,201				$ 305,201		$ 260,009	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage		$ 260,009
Average Remaining Life		10.37
Theoretical Reserve %		85.19%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37670**
Plant Account **REG AFUDC**

Survivor Curve SQ
Average Service Life 40
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0050	$ -	39.80
2025	$ -	1.5	4	100.00%	$ -	0.0350	$ -	38.60
2024	$ -	2.5	6	100.00%	$ -	0.0550	$ -	37.80
2023	$ -	3.5	9	100.00%	$ -	0.0850	$ -	36.60
2022	$ -	4.5	11	100.00%	$ -	0.1050	$ -	35.80
2021	$ 1,322,088	5.5	14	100.00%	$ 1,322,088	0.1350	$ 178,482	34.60
2020	$ -	6.5	16	100.00%	$ -	0.1550	$ -	33.80
2019	$ -	7.5	19	100.00%	$ -	0.1850	$ -	32.60
2018	$ -	8.5	21	100.00%	$ -	0.2050	$ -	31.80
2017	$ -	9.5	24	100.00%	$ -	0.2350	$ -	30.60
2016	$ -	10.5	26	100.00%	$ -	0.2550	$ -	29.80
2015	$ -	11.5	29	100.00%	$ -	0.2850	$ -	28.60
2014	$ -	12.5	31	100.00%	$ -	0.3050	$ -	27.80
2013	$ -	13.5	34	100.00%	$ -	0.3350	$ -	26.60
2012	$ -	14.5	36	100.00%	$ -	0.3550	$ -	25.80
2011	$ -	15.5	39	100.00%	$ -	0.3850	$ -	24.60
2010	$ -	16.5	41	100.00%	$ -	0.4050	$ -	23.80
2009	$ -	17.5	44	100.00%	$ -	0.4350	$ -	22.60
2008	$ -	18.5	46	100.00%	$ -	0.4550	$ -	21.80
2007	$ -	19.5	49	100.00%	$ -	0.4850	$ -	20.60
2006	$ -	20.5	51	100.00%	$ -	0.5050	$ -	19.80
2005	$ -	21.5	54	100.00%	$ -	0.5350	$ -	18.60
2004	$ -	22.5	56	100.00%	$ -	0.5550	$ -	17.80
2003	$ -	23.5	59	100.00%	$ -	0.5850	$ -	16.60
2002	$ -	24.5	61	100.00%	$ -	0.6050	$ -	15.80
2001	$ -	25.5	64	100.00%	$ -	0.6350	$ -	14.60
2000	$ -	26.5	66	100.00%	$ -	0.6550	$ -	13.80
1999	$ -	27.5	69	100.00%	$ -	0.6850	$ -	12.60
1998	$ -	28.5	71	100.00%	$ -	0.7050	$ -	11.80
1997	$ -	29.5	74	100.00%	$ -	0.7350	$ -	10.60
1996	$ -	30.5	76	100.00%	$ -	0.7550	$ -	9.80

1995	$	-	31.5	79	100.00%	$	-	0.7850	$	-	8.60
1994	$	-	32.5	81	100.00%	$	-	0.8050	$	-	7.80
1993	$	-	33.5	84	100.00%	$	-	0.8350	$	-	6.60
1992	$	-	34.5	86	100.00%	$	-	0.8550	$	-	5.80
1991	$	-	35.5	89	100.00%	$	-	0.8850	$	-	4.60
1990	$	-	36.5	91	100.00%	$	-	0.9050	$	-	3.80
1989	$	-	37.5	94	100.00%	$	-	0.9350	$	-	2.60
1988	$	-	38.5	96	100.00%	$	-	0.9550	$	-	1.80
1987	$	-	39.5	99	100.00%	$	-	0.9850	$	-	0.60
1986	$	-	40.5	101	100.00%	$	-	1.0000	$	-	0.00
1985	$	-	41.5	104	100.00%	$	-	1.0000	$	-	0.00
1984	$	-	42.5	106	100.00%	$	-	1.0000	$	-	0.00
1983	$	-	43.5	109	100.00%	$	-	1.0000	$	-	0.00
1982	$	-	44.5	111	100.00%	$	-	1.0000	$	-	0.00
1981	$	-	45.5	114	100.00%	$	-	1.0000	$	-	0.00
1980	$	-	46.5	116	100.00%	$	-	1.0000	$	-	0.00
1979	$	-	47.5	119	100.00%	$	-	1.0000	$	-	0.00
1978	$	-	48.5	121	100.00%	$	-	1.0000	$	-	0.00
1977	$	-	49.5	124	100.00%	$	-	1.0000	$	-	0.00
1976	$	-	50.5	126	100.00%	$	-	1.0000	$	-	0.00
1975	$	-	51.5	129	100.00%	$	-	1.0000	$	-	0.00
1974	$	-	52.5	131	100.00%	$	-	1.0000	$	-	0.00
1973	$	-	53.5	134	100.00%	$	-	1.0000	$	-	0.00
1972	$	-	54.5	136	100.00%	$	-	1.0000	$	-	0.00
1971	$	-	55.5	139	100.00%	$	-	1.0000	$	-	0.00
1970	$	-	56.5	141	100.00%	$	-	1.0000	$	-	0.00
1969	$	-	57.5	144	100.00%	$	-	1.0000	$	-	0.00
1968	$	-	58.5	146	100.00%	$	-	1.0000	$	-	0.00
1967	$	-	59.5	149	100.00%	$	-	1.0000	$	-	0.00
1966	$	-	60.5	151	100.00%	$	-	1.0000	$	-	0.00
1965	$	-	61.5	154	100.00%	$	-	1.0000	$	-	0.00
1964	$	-	62.5	156	100.00%	$	-	1.0000	$	-	0.00
1963	$	-	63.5	159	100.00%	$	-	1.0000	$	-	0.00
1962	$	-	64.5	161	100.00%	$	-	1.0000	$	-	0.00
1961	$	-	65.5	164	100.00%	$	-	1.0000	$	-	0.00
1960	$	-	66.5	166	100.00%	$	-	1.0000	$	-	0.00
1959	$	-	67.5	169	100.00%	$	-	1.0000	$	-	0.00
1958	$	-	68.5	171	100.00%	$	-	1.0000	$	-	0.00
1957	$	-	69.5	174	100.00%	$	-	1.0000	$	-	0.00
1956	$	-	70.5	176	100.00%	$	-	1.0000	$	-	0.00
1955	$	-	71.5	179	100.00%	$	-	1.0000	$	-	0.00
1954	$	-	72.5	181	100.00%	$	-	1.0000	$	-	0.00
1953	$	-	73.5	184	100.00%	$	-	1.0000	$	-	0.00
1952	$	-	74.5	186	100.00%	$	-	1.0000	$	-	0.00
1951	$	-	75.5	189	100.00%	$	-	1.0000	$	-	0.00
1950	$	-	76.5	191	100.00%	$	-	1.0000	$	-	0.00
1949	$	-	77.5	194	100.00%	$	-	1.0000	$	-	0.00
1948	$	-	78.5	196	100.00%	$	-	1.0000	$	-	0.00
1947	$	-	79.5	199	100.00%	$	-	1.0000	$	-	0.00

1946	$	-	80.5	201	100.00%	$	-	1.0000	$	-	0.00
1945	$	-	81.5	204	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	206	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	209	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	211	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	214	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	216	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	219	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	221	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	224	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	226	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	229	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	231	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	234	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	236	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	239	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	241	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	244	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	246	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	249	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	251	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	254	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	256	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	259	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	261	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	264	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	266	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	269	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	271	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	274	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	276	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	279	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	281	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	284	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	286	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	289	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	291	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	294	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	296	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	299	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	301	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	304	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	306	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	309	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	311	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	314	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	316	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	319	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	321	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	324	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	326	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	329	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	331	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	334	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	336	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	339	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	341	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	344	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	346	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	349	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	351	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	354	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	356	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	359	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	361	100.00%	$ -	1.0000	$ -	0.00
Total	$ 1,322,088				$ 1,322,088		$ 178,482	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage	$	178,482
Average Remaining Life		34.60
Theoretical Reserve %		13.50%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37800**
Plant Account **MEASURING AND REGULATING STATION EQUIPMENT - GENERAL**

Survivor Curve R0.5
Average Service Life 53
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 27,442,457	0.5	1	100.00%	$ 27,442,457	0.0062	$ 170,143	52.67
2025	$ 7,709,676	1.5	3	100.00%	$ 7,709,676	0.0186	$ 143,400	52.01
2024	$ 9,268,243	2.5	5	100.00%	$ 9,268,243	0.0310	$ 287,316	51.36
2023	$ 12,678,211	3.5	7	100.00%	$ 12,678,211	0.0433	$ 548,967	50.71
2022	$ 19,173,789	4.5	8	100.00%	$ 19,173,789	0.0495	$ 949,103	50.38
2021	$ 14,768,466	5.5	10	100.00%	$ 14,768,466	0.0617	$ 911,214	49.73
2020	$ 9,022,482	6.5	12	100.00%	$ 9,022,482	0.0740	$ 667,664	49.08
2019	$ 9,622,541	7.5	14	100.00%	$ 9,622,541	0.0862	$ 829,463	48.43
2018	$ 12,728,766	8.5	16	100.00%	$ 12,728,766	0.0984	$ 1,252,511	47.78
2017	$ 5,681,927	9.5	18	100.00%	$ 5,681,927	0.1105	$ 627,853	47.14
2016	$ 5,406,679	10.5	20	100.00%	$ 5,406,679	0.1227	$ 663,399	46.50
2015	$ 9,336,473	11.5	22	100.00%	$ 9,336,473	0.1347	$ 1,257,623	45.86
2014	$ 6,308,219	12.5	24	100.00%	$ 6,308,219	0.1468	$ 926,047	45.22
2013	$ 1,879,405	13.5	25	100.00%	$ 1,879,405	0.1528	$ 287,173	44.90
2012	$ 3,222,882	14.5	27	100.00%	$ 3,222,882	0.1649	$ 531,453	44.26
2011	$ 4,706,889	15.5	29	100.00%	$ 4,706,889	0.1769	$ 832,649	43.62
2010	$ 790,434	16.5	31	100.00%	$ 790,434	0.1888	$ 149,234	42.99
2009	$ 995,661	17.5	33	100.00%	$ 995,661	0.2008	$ 199,929	42.36
2008	$ 2,639,761	18.5	35	100.00%	$ 2,639,761	0.2127	$ 561,477	41.73
2007	$ 2,009,227	19.5	37	100.00%	$ 2,009,227	0.2246	$ 451,272	41.10
2006	$ 1,325,314	20.5	39	100.00%	$ 1,325,314	0.2365	$ 313,437	40.47
2005	$ 1,613,337	21.5	41	100.00%	$ 1,613,337	0.2483	$ 400,591	39.84
2004	$ 1,976,733	22.5	42	100.00%	$ 1,976,733	0.2542	$ 502,486	39.53
2003	$ 2,538,791	23.5	44	100.00%	$ 2,538,791	0.2660	$ 675,319	38.90
2002	$ 734,299	24.5	46	100.00%	$ 734,299	0.2777	$ 203,915	38.28
2001	$ 1,314,212	25.5	48	100.00%	$ 1,314,212	0.2894	$ 380,333	37.66
2000	$ 1,247,730	26.5	50	100.00%	$ 1,247,730	0.3010	$ 375,567	37.05
1999	$ 422,444	27.5	52	100.00%	$ 422,444	0.3126	$ 132,056	36.43
1998	$ 1,210,639	28.5	54	100.00%	$ 1,210,639	0.3241	$ 392,368	35.82
1997	$ 882,778	29.5	56	100.00%	$ 882,778	0.3356	$ 296,260	35.21
1996	$ 1,195,234	30.5	58	100.00%	$ 1,195,234	0.3470	$ 414,746	34.61

1995	$ 924,951	31.5	59	100.00%	$ 924,951	0.3527	$ 326,230	34.31
1994	$ 738,214	32.5	61	100.00%	$ 738,214	0.3640	$ 268,710	33.71
1993	$ 368,369	33.5	63	100.00%	$ 368,369	0.3753	$ 138,249	33.11
1992	$ 571,598	34.5	65	100.00%	$ 571,598	0.3865	$ 220,923	32.52
1991	$ 402,560	35.5	67	100.00%	$ 402,560	0.3975	$ 160,018	31.93
1990	$ 319,972	36.5	69	100.00%	$ 319,972	0.4086	$ 130,740	31.34
1989	$ 645,224	37.5	71	100.00%	$ 645,224	0.4195	$ 270,671	30.77
1988	$ 348,440	38.5	73	100.00%	$ 348,440	0.4304	$ 149,969	30.19
1987	$ 490,227	39.5	75	100.00%	$ 490,227	0.4411	$ 216,239	29.62
1986	$ 416,036	40.5	76	100.00%	$ 416,036	0.4465	$ 185,760	29.34
1985	$ 381,537	41.5	78	100.00%	$ 381,537	0.4571	$ 174,400	28.77
1984	$ 188,694	42.5	80	100.00%	$ 188,694	0.4677	$ 88,252	28.21
1983	$ 321,442	43.5	82	100.00%	$ 321,442	0.4782	$ 153,713	27.66
1982	$ 585,832	44.5	84	100.00%	$ 585,832	0.4885	$ 286,179	27.11
1981	$ 738,217	45.5	86	100.00%	$ 738,217	0.4988	$ 368,223	26.56
1980	$ 255,105	46.5	88	100.00%	$ 255,105	0.5090	$ 129,848	26.02
1979	$ 90,220	47.5	90	100.00%	$ 90,220	0.5191	$ 46,833	25.49
1978	$ 83,461	48.5	92	100.00%	$ 83,461	0.5291	$ 44,159	24.96
1977	$ 252,122	49.5	93	100.00%	$ 252,122	0.5341	$ 134,658	24.69
1976	$ 144,728	50.5	95	100.00%	$ 144,728	0.5440	$ 78,732	24.17
1975	$ 80,397	51.5	97	100.00%	$ 80,397	0.5538	$ 44,524	23.65
1974	$ 163,376	52.5	99	100.00%	$ 163,376	0.5634	$ 92,046	23.14
1973	$ 188,372	53.5	101	100.00%	$ 188,372	0.5730	$ 107,937	22.63
1972	$ 131,240	54.5	103	100.00%	$ 131,240	0.5825	$ 76,447	22.13
1971	$ 374,667	55.5	105	100.00%	$ 374,667	0.5919	$ 221,766	21.63
1970	$ 401,009	56.5	107	100.00%	$ 401,009	0.6013	$ 241,127	21.13
1969	$ 458,182	57.5	108	100.00%	$ 458,182	0.6059	$ 277,612	20.89
1968	$ 207,200	58.5	110	100.00%	$ 207,200	0.6151	$ 127,449	20.40
1967	$ 167,928	59.5	112	100.00%	$ 167,928	0.6242	$ 104,820	19.92
1966	$ 133,402	60.5	114	100.00%	$ 133,402	0.6332	$ 84,470	19.44
1965	$ 153,781	61.5	116	100.00%	$ 153,781	0.6421	$ 98,743	18.97
1964	$ 83,503	62.5	118	100.00%	$ 83,503	0.6510	$ 54,360	18.50
1963	$ 88,772	63.5	120	100.00%	$ 88,772	0.6597	$ 58,563	18.04
1962	$ 70,556	64.5	122	100.00%	$ 70,556	0.6684	$ 47,160	17.57
1961	$ 63,356	65.5	124	100.00%	$ 63,356	0.6770	$ 42,892	17.12
1960	$ 67,538	66.5	125	100.00%	$ 67,538	0.6813	$ 46,014	16.89
1959	$ 18,763	67.5	127	100.00%	$ 18,763	0.6898	$ 12,943	16.44
1958	$ 93,865	68.5	129	100.00%	$ 93,865	0.6983	$ 65,546	15.99
1957	$ 103,189	69.5	131	100.00%	$ 103,189	0.7066	$ 72,913	15.55
1956	$ 100,928	70.5	133	100.00%	$ 100,928	0.7149	$ 72,154	15.11
1955	$ 31,268	71.5	135	100.00%	$ 31,268	0.7232	$ 22,613	14.67
1954	$ 60,238	72.5	137	100.00%	$ 60,238	0.7314	$ 44,058	14.24
1953	$ 17,353	73.5	139	100.00%	$ 17,353	0.7395	$ 12,832	13.81
1952	$ 20,724	74.5	141	100.00%	$ 20,724	0.7476	$ 15,493	13.38
1951	$ 9,061	75.5	142	100.00%	$ 9,061	0.7517	$ 6,811	13.16
1950	$ 12,290	76.5	144	100.00%	$ 12,290	0.7597	$ 9,336	12.74
1949	$ 1,343	77.5	146	100.00%	$ 1,343	0.7677	$ 1,031	12.31
1948	$ 2,253	78.5	148	100.00%	$ 2,253	0.7757	$ 1,748	11.89
1947	$ 3,047	79.5	150	100.00%	$ 3,047	0.7836	$ 2,388	11.47

1946	$	828	80.5	152	100.00%	$	828	0.7915	$	656	11.05
1945	$	762	81.5	154	100.00%	$	762	0.7994	$	609	10.63
1944	$	-	82.5	156	100.00%	$	-	0.8074	$	-	10.21
1943	$	942	83.5	158	100.00%	$	942	0.8153	$	768	9.79
1942	$	2,229	84.5	159	100.00%	$	2,229	0.8192	$	1,826	9.58
1941	$	313	85.5	161	100.00%	$	313	0.8272	$	259	9.16
1940	$	277	86.5	163	100.00%	$	277	0.8352	$	231	8.73
1939	$	442	87.5	165	100.00%	$	442	0.8432	$	372	8.31
1938	$	456	88.5	167	100.00%	$	456	0.8513	$	389	7.88
1937	$	2,403	89.5	169	100.00%	$	2,403	0.8594	$	2,065	7.45
1936	$	830	90.5	171	100.00%	$	830	0.8676	$	720	7.02
1935	$	328	91.5	173	100.00%	$	328	0.8759	$	288	6.58
1934	$	271	92.5	175	100.00%	$	271	0.8843	$	240	6.13
1933	$	-	93.5	176	100.00%	$	-	0.8885	$	-	5.91
1932	$	303	94.5	178	100.00%	$	303	0.8971	$	271	5.45
1931	$	2,358	95.5	180	100.00%	$	2,358	0.9058	$	2,136	4.99
1930	$	882	96.5	182	100.00%	$	882	0.9146	$	807	4.53
1929	$	759	97.5	184	100.00%	$	759	0.9236	$	701	4.05
1928	$	1,864	98.5	186	100.00%	$	1,864	0.9328	$	1,739	3.56
1927	$	2,645	99.5	188	100.00%	$	2,645	0.9421	$	2,491	3.07
1926	$	1,340	100.5	190	100.00%	$	1,340	0.9515	$	1,275	2.57
1925	$	-	101.5	192	100.00%	$	-	0.9610	$	-	2.07
1924	$	953	102.5	193	100.00%	$	953	0.9657	$	920	1.82
1923	$	340	103.5	195	100.00%	$	340	0.9753	$	332	1.31
1922	$	244	104.5	197	100.00%	$	244	0.9851	$	240	0.79
1921	$	61	105.5	199	100.00%	$	61	0.9949	$	60	0.27
1920	$	204	106.5	201	100.00%	$	204	1.0000	$	204	0.00
1919	$	855	107.5	203	100.00%	$	855	1.0000	$	855	0.00
1918	$	-	108.5	205	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	207	100.00%	$	-	1.0000	$	-	0.00
1916	$	179	110.5	208	100.00%	$	179	1.0000	$	179	0.00
1915	$	-	111.5	210	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	212	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	214	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	216	100.00%	$	-	1.0000	$	-	0.00
1911	$	76	115.5	218	100.00%	$	76	1.0000	$	76	0.00
1910	$	112	116.5	220	100.00%	$	112	1.0000	$	112	0.00
1909	$	-	117.5	222	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	224	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	225	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	227	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	229	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	231	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	233	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	235	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	237	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	239	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	241	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	242	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	244	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	246	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	248	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	250	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	252	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	254	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	256	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	258	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	259	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	261	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	263	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	265	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	267	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	269	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	271	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	273	100.00%	$ -	1.0000	$ -	0.00
Total	$191,451,498				$191,451,498		$ 21,994,091	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage		$ 21,994,091
Average Remaining Life		46.91
Theoretical Reserve %	11.49%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **37900**
Plant Account **MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE**

Survivor Curve R1.5
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0083	$ -	44.63
2025	$ 15,684,607	1.5	3	100.00%	$ 15,684,607	0.0247	$ 387,410	43.89
2024	$ 2,841,977	2.5	6	100.00%	$ 2,841,977	0.0492	$ 139,825	42.79
2023	$ 17,158,423	3.5	8	100.00%	$ 17,158,423	0.0653	$ 1,120,445	42.06
2022	$ 21,436,668	4.5	10	100.00%	$ 21,436,668	0.0814	$ 1,744,945	41.34
2021	$ 1,952,033	5.5	12	100.00%	$ 1,952,033	0.0974	$ 190,128	40.62
2020	$ 542,593	6.5	14	100.00%	$ 542,593	0.1133	$ 61,476	39.90
2019	$ 2,419,389	7.5	17	100.00%	$ 2,419,389	0.1370	$ 331,456	38.84
2018	$ 1	8.5	19	100.00%	$ 1	0.1527	$ -	38.13
2017	$ 32,074	9.5	21	100.00%	$ 32,074	0.1683	$ 5,398	37.43
2016	$ 168,831	10.5	23	100.00%	$ 168,831	0.1837	$ 31,014	36.73
2015	$ 784,772	11.5	26	100.00%	$ 784,772	0.2068	$ 162,291	35.69
2014	$ 7,929,732	12.5	28	100.00%	$ 7,929,732	0.2220	$ 1,760,401	35.01
2013	$ 309,792	13.5	30	100.00%	$ 309,792	0.2372	$ 73,483	34.33
2012	$ 964,736	14.5	32	100.00%	$ 964,736	0.2522	$ 243,307	33.65
2011	$ 1,348,202	15.5	34	100.00%	$ 1,348,202	0.2672	$ 360,240	32.98
2010	$ 265,810	16.5	37	100.00%	$ 265,810	0.2894	$ 76,925	31.98
2009	$ 77,274	17.5	39	100.00%	$ 77,274	0.3041	$ 23,499	31.32
2008	$ 460,996	18.5	41	100.00%	$ 460,996	0.3187	$ 146,919	30.66
2007	$ 9,462	19.5	43	100.00%	$ 9,462	0.3331	$ 3,152	30.01
2006	$ 162,734	20.5	46	100.00%	$ 162,734	0.3546	$ 57,705	29.04
2005	$ 48,588	21.5	48	100.00%	$ 48,588	0.3687	$ 17,914	28.41
2004	$ 75,956	22.5	50	100.00%	$ 75,956	0.3827	$ 29,069	27.78
2003	$ 453,985	23.5	52	100.00%	$ 453,985	0.3966	$ 180,051	27.15
2002	$ 184,889	24.5	54	100.00%	$ 184,889	0.4104	$ 75,878	26.53
2001	$ 173,987	25.5	57	100.00%	$ 173,987	0.4307	$ 74,936	25.62
2000	$ 69,704	26.5	59	100.00%	$ 69,704	0.4441	$ 30,956	25.02
1999	$ 58,548	27.5	61	100.00%	$ 58,548	0.4573	$ 26,774	24.42
1998	$ 126,465	28.5	63	100.00%	$ 126,465	0.4703	$ 59,476	23.84
1997	$ 515,666	29.5	66	100.00%	$ 515,666	0.4896	$ 252,470	22.97
1996	$ 434,624	30.5	68	100.00%	$ 434,624	0.5023	$ 218,312	22.40

1995	$	307,818	31.5	70	100.00%	$	307,818	0.5147	$	158,434	21.84
1994	$	89,128	32.5	72	100.00%	$	89,128	0.5270	$	46,970	21.29
1993	$	82,155	33.5	74	100.00%	$	82,155	0.5391	$	44,290	20.74
1992	$	199,536	34.5	77	100.00%	$	199,536	0.5569	$	111,122	19.94
1991	$	273,309	35.5	79	100.00%	$	273,309	0.5686	$	155,404	19.41
1990	$	136,693	36.5	81	100.00%	$	136,693	0.5800	$	79,282	18.90
1989	$	43,574	37.5	83	100.00%	$	43,574	0.5913	$	25,766	18.39
1988	$	249,268	38.5	86	100.00%	$	249,268	0.6078	$	151,505	17.65
1987	$	794,036	39.5	88	100.00%	$	794,036	0.6185	$	491,111	17.17
1986	$	266,532	40.5	90	100.00%	$	266,532	0.6290	$	167,649	16.70
1985	$	466,515	41.5	92	100.00%	$	466,515	0.6394	$	298,290	16.23
1984	$	201,775	42.5	94	100.00%	$	201,775	0.6495	$	131,053	15.77
1983	$	13,339	43.5	97	100.00%	$	13,339	0.6643	$	8,861	15.11
1982	$	255,982	44.5	99	100.00%	$	255,982	0.6739	$	172,506	14.67
1981	$	769,867	45.5	101	100.00%	$	769,867	0.6833	$	526,050	14.25
1980	$	52,352	46.5	103	100.00%	$	52,352	0.6925	$	36,254	13.84
1979	$	2,896	47.5	106	100.00%	$	2,896	0.7059	$	2,044	13.23
1978	$	17,858	48.5	108	100.00%	$	17,858	0.7145	$	12,760	12.85
1977	$	2,192	49.5	110	100.00%	$	2,192	0.7230	$	1,585	12.47
1976	$	16,445	50.5	112	100.00%	$	16,445	0.7313	$	12,026	12.09
1975	$	62,366	51.5	114	100.00%	$	62,366	0.7393	$	46,107	11.73
1974	$	41,739	52.5	117	100.00%	$	41,739	0.7511	$	31,350	11.20
1973	$	40,179	53.5	119	100.00%	$	40,179	0.7587	$	30,483	10.86
1972	$	40,456	54.5	121	100.00%	$	40,456	0.7661	$	30,993	10.53
1971	$	13,946	55.5	123	100.00%	$	13,946	0.7733	$	10,784	10.20
1970	$	19,306	56.5	126	100.00%	$	19,306	0.7798	$	15,055	9.91
1969	$	132,498	57.5	128	100.00%	$	132,498	0.7905	$	104,740	9.43
1968	$	123,199	58.5	130	100.00%	$	123,199	0.7972	$	98,214	9.13
1967	$	21,446	59.5	132	100.00%	$	21,446	0.8038	$	17,238	8.83
1966	$	137,158	60.5	134	100.00%	$	137,158	0.8102	$	111,126	8.54
1965	$	59,628	61.5	137	100.00%	$	59,628	0.8197	$	48,877	8.11
1964	$	1,611	62.5	139	100.00%	$	1,611	0.8258	$	1,330	7.84
1963	$	28,748	63.5	141	100.00%	$	28,748	0.8319	$	23,915	7.56
1962	$	30,650	64.5	143	100.00%	$	30,650	0.8379	$	25,681	7.29
1961	$	1,916	65.5	146	100.00%	$	1,916	0.8466	$	1,622	6.90
1960	$	47,097	66.5	148	100.00%	$	47,097	0.8524	$	40,146	6.64
1959	$	4,745	67.5	150	100.00%	$	4,745	0.8581	$	4,072	6.39
1958	$	9,673	68.5	152	100.00%	$	9,673	0.8637	$	8,355	6.13
1957	$	5,372	69.5	154	100.00%	$	5,372	0.8692	$	4,670	5.89
1956	$	22,710	70.5	157	100.00%	$	22,710	0.8772	$	19,921	5.53
1955	$	-	71.5	159	100.00%	$	-	0.8825	$	-	5.29
1954	$	1,597	72.5	161	100.00%	$	1,597	0.8876	$	1,417	5.06
1953	$	-	73.5	163	100.00%	$	-	0.8926	$	-	4.83
1952	$	-	74.5	166	100.00%	$	-	0.8999	$	-	4.50
1951	$	-	75.5	168	100.00%	$	-	0.9046	$	-	4.29
1950	$	-	76.5	170	100.00%	$	-	0.9091	$	-	4.09
1949	$	-	77.5	172	100.00%	$	-	0.9136	$	-	3.89
1948	$	-	78.5	174	100.00%	$	-	0.9181	$	-	3.69
1947	$	-	79.5	177	100.00%	$	-	0.9250	$	-	3.38

1946	$	-	80.5	179	100.00%	$	-	0.9298	$	-	3.16
1945	$	-	81.5	181	100.00%	$	-	0.9349	$	-	2.93
1944	$	-	82.5	183	100.00%	$	-	0.9405	$	-	2.68
1943	$	-	83.5	186	100.00%	$	-	0.9500	$	-	2.25
1942	$	-	84.5	188	100.00%	$	-	0.9567	$	-	1.95
1941	$	-	85.5	190	100.00%	$	-	0.9635	$	-	1.64
1940	$	-	86.5	192	100.00%	$	-	0.9703	$	-	1.34
1939	$	-	87.5	194	100.00%	$	-	0.9769	$	-	1.04
1938	$	-	88.5	197	100.00%	$	-	0.9868	$	-	0.59
1937	$	-	89.5	199	100.00%	$	-	0.9928	$	-	0.32
1936	$	-	90.5	201	100.00%	$	-	0.0000	$	-	45.00
1935	$	-	91.5	203	100.00%	$	-	0.0000	$	-	45.00
1934	$	-	92.5	206	100.00%	$	-	0.0000	$	-	45.00
1933	$	-	93.5	208	100.00%	$	-	0.0000	$	-	45.00
1932	$	-	94.5	210	100.00%	$	-	0.0000	$	-	45.00
1931	$	-	95.5	212	100.00%	$	-	0.0000	$	-	45.00
1930	$	-	96.5	214	100.00%	$	-	0.0000	$	-	45.00
1929	$	-	97.5	217	100.00%	$	-	0.0000	$	-	45.00
1928	$	-	98.5	219	100.00%	$	-	0.0000	$	-	45.00
1927	$	-	99.5	221	100.00%	$	-	0.0000	$	-	45.00
1926	$	-	100.5	223	100.00%	$	-	0.0000	$	-	45.00
1925	$	-	101.5	226	100.00%	$	-	0.0000	$	-	45.00
1924	$	-	102.5	228	100.00%	$	-	0.0000	$	-	45.00
1923	$	-	103.5	230	100.00%	$	-	0.0000	$	-	45.00
1922	$	-	104.5	232	100.00%	$	-	0.0000	$	-	45.00
1921	$	-	105.5	234	100.00%	$	-	0.0000	$	-	45.00
1920	$	-	106.5	237	100.00%	$	-	0.0000	$	-	45.00
1919	$	-	107.5	239	100.00%	$	-	0.0000	$	-	45.00
1918	$	-	108.5	241	100.00%	$	-	0.0000	$	-	45.00
1917	$	-	109.5	243	100.00%	$	-	0.0000	$	-	45.00
1916	$	-	110.5	246	100.00%	$	-	0.0000	$	-	45.00
1915	$	-	111.5	248	100.00%	$	-	0.0000	$	-	45.00
1914	$	-	112.5	250	100.00%	$	-	0.0000	$	-	45.00
1913	$	-	113.5	252	100.00%	$	-	0.0000	$	-	45.00
1912	$	-	114.5	254	100.00%	$	-	0.0000	$	-	45.00
1911	$	-	115.5	257	100.00%	$	-	0.0000	$	-	45.00
1910	$	-	116.5	259	100.00%	$	-	0.0000	$	-	45.00
1909	$	-	117.5	261	100.00%	$	-	0.0000	$	-	45.00
1908	$	-	118.5	263	100.00%	$	-	0.0000	$	-	45.00
1907	$	-	119.5	266	100.00%	$	-	0.0000	$	-	45.00
1906	$	-	120.5	268	100.00%	$	-	0.0000	$	-	45.00
1905	$	-	121.5	270	100.00%	$	-	0.0000	$	-	45.00
1904	$	-	122.5	272	100.00%	$	-	0.0000	$	-	45.00
1903	$	-	123.5	274	100.00%	$	-	0.0000	$	-	45.00
1902	$	-	124.5	277	100.00%	$	-	0.0000	$	-	45.00
1901	$	-	125.5	279	100.00%	$	-	0.0000	$	-	45.00
1900	$	-	126.5	281	100.00%	$	-	0.0000	$	-	45.00
1899	$	-	127.5	283	100.00%	$	-	0.0000	$	-	45.00
1898	$	-	128.5	286	100.00%	$	-	0.0000	$	-	45.00

1897	$ -	129.5	288	100.00%	$ -	0.0000	$ -	45.00
1896	$ -	130.5	290	100.00%	$ -	0.0000	$ -	45.00
1895	$ -	131.5	292	100.00%	$ -	0.0000	$ -	45.00
1894	$ -	132.5	294	100.00%	$ -	0.0000	$ -	45.00
1893	$ -	133.5	297	100.00%	$ -	0.0000	$ -	45.00
1892	$ -	134.5	299	100.00%	$ -	0.0000	$ -	45.00
1891	$ -	135.5	301	100.00%	$ -	0.0000	$ -	45.00
1890	$ -	136.5	303	100.00%	$ -	0.0000	$ -	45.00
1889	$ -	137.5	306	100.00%	$ -	0.0000	$ -	45.00
1888	$ -	138.5	308	100.00%	$ -	0.0000	$ -	45.00
1887	$ -	139.5	310	100.00%	$ -	0.0000	$ -	45.00
1886	$ -	140.5	312	100.00%	$ -	0.0000	$ -	45.00
1885	$ -	141.5	314	100.00%	$ -	0.0000	$ -	45.00
1884	$ -	142.5	317	100.00%	$ -	0.0000	$ -	45.00
1883	$ -	143.5	319	100.00%	$ -	0.0000	$ -	45.00
1882	$ -	144.5	321	100.00%	$ -	0.0000	$ -	45.00
Total	$ 81,779,824				$ 81,779,824		$ 11,194,913	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 11,194,913
Average Remaining Life	38.84
Theoretical Reserve %	13.69%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38000**
Plant Account **SERVICES**

Survivor Curve R2
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 134,032,544	0.5	1	100.00%	$ 134,032,544	0.0091	$ 1,219,696	44.59
2025	$ 80,573,640	1.5	3	100.00%	$ 80,573,640	0.0271	$ 2,183,546	43.78
2024	$ 95,769,253	2.5	6	100.00%	$ 95,769,253	0.0540	$ 5,171,540	42.57
2023	$ 130,556,986	3.5	8	100.00%	$ 130,556,986	0.0717	$ 9,360,936	41.77
2022	$ 129,987,104	4.5	10	100.00%	$ 129,987,104	0.0894	$ 11,620,847	40.98
2021	$ 115,386,660	5.5	12	100.00%	$ 115,386,660	0.1070	$ 12,346,373	40.19
2020	$ 79,437,898	6.5	14	100.00%	$ 79,437,898	0.1244	$ 9,882,074	39.40
2019	$ 93,887,568	7.5	17	100.00%	$ 93,887,568	0.1503	$ 14,111,301	38.24
2018	$ 69,437,921	8.5	19	100.00%	$ 69,437,921	0.1675	$ 11,630,852	37.46
2017	$ 64,931,515	9.5	21	100.00%	$ 64,931,515	0.1845	$ 11,979,864	36.70
2016	$ 65,389,958	10.5	23	100.00%	$ 65,389,958	0.2014	$ 13,169,538	35.94
2015	$ 61,715,195	11.5	26	100.00%	$ 61,715,195	0.2265	$ 13,978,492	34.81
2014	$ 55,939,710	12.5	28	100.00%	$ 55,939,710	0.2430	$ 13,593,349	34.07
2013	$ 56,668,298	13.5	30	100.00%	$ 56,668,298	0.2595	$ 14,705,423	33.32
2012	$ 45,866,475	14.5	32	100.00%	$ 45,866,475	0.2757	$ 12,645,387	32.59
2011	$ 34,487,638	15.5	34	100.00%	$ 34,487,638	0.2919	$ 10,066,941	31.86
2010	$ 21,392,855	16.5	37	100.00%	$ 21,392,855	0.3158	$ 6,755,864	30.79
2009	$ 22,796,428	17.5	39	100.00%	$ 22,796,428	0.3316	$ 7,559,296	30.08
2008	$ 23,113,776	18.5	41	100.00%	$ 23,113,776	0.3472	$ 8,025,103	29.38
2007	$ 18,414,003	19.5	43	100.00%	$ 18,414,003	0.3627	$ 6,678,759	28.68
2006	$ 16,648,370	20.5	46	100.00%	$ 16,648,370	0.3855	$ 6,417,947	27.65
2005	$ 18,899,125	21.5	48	100.00%	$ 18,899,125	0.4006	$ 7,570,990	26.97
2004	$ 24,540,130	22.5	50	100.00%	$ 24,540,130	0.4155	$ 10,196,424	26.30
2003	$ 15,936,563	23.5	52	100.00%	$ 15,936,563	0.4302	$ 6,855,910	25.64
2002	$ 17,394,076	24.5	54	100.00%	$ 17,394,076	0.4447	$ 7,735,146	24.99
2001	$ 17,363,761	25.5	57	100.00%	$ 17,363,761	0.4662	$ 8,094,985	24.02
2000	$ 15,242,498	26.5	59	100.00%	$ 15,242,498	0.4803	$ 7,320,972	23.39
1999	$ 15,476,324	27.5	61	100.00%	$ 15,476,324	0.4942	$ 7,648,399	22.76
1998	$ 17,103,536	28.5	63	100.00%	$ 17,103,536	0.5080	$ 8,688,596	22.14
1997	$ 20,245,652	29.5	66	100.00%	$ 20,245,652	0.5282	$ 10,693,753	21.23
1996	$ 17,636,395	30.5	68	100.00%	$ 17,636,395	0.5414	$ 9,548,344	20.64
1995	$ 19,789,594	31.5	70	100.00%	$ 19,789,594	0.5544	$ 10,971,351	20.05
1994	$ 18,472,257	32.5	72	100.00%	$ 18,472,257	0.5673	$ 10,479,311	19.47

1993	$ 12,352,511	33.5	74	100.00%	$ 12,352,511	0.5799	$ 7,163,221	18.90
1992	$ 13,901,863	34.5	77	100.00%	$ 13,901,863	0.5984	$ 8,318,875	18.07
1991	$ 13,556,497	35.5	79	100.00%	$ 13,556,497	0.6105	$ 8,276,242	17.53
1990	$ 15,071,733	36.5	81	100.00%	$ 15,071,733	0.6223	$ 9,379,140	17.00
1989	$ 13,850,074	37.5	83	100.00%	$ 13,850,074	0.6339	$ 8,779,562	16.47
1988	$ 11,466,893	38.5	86	100.00%	$ 11,466,893	0.6510	$ 7,464,948	15.71
1987	$ 8,589,672	39.5	88	100.00%	$ 8,589,672	0.6620	$ 5,686,363	15.21
1986	$ 7,076,543	40.5	90	100.00%	$ 7,076,543	0.6728	$ 4,761,098	14.72
1985	$ 6,125,350	41.5	92	100.00%	$ 6,125,350	0.6834	$ 4,186,064	14.25
1984	$ 5,153,661	42.5	94	100.00%	$ 5,153,661	0.6938	$ 3,575,610	13.78
1983	$ 4,413,037	43.5	97	100.00%	$ 4,413,037	0.7088	$ 3,127,960	13.10
1982	$ 5,665,735	44.5	99	100.00%	$ 5,665,735	0.7186	$ 4,071,397	12.66
1981	$ 6,551,613	45.5	101	100.00%	$ 6,551,613	0.7281	$ 4,770,230	12.24
1980	$ 6,640,175	46.5	103	100.00%	$ 6,640,175	0.7374	$ 4,896,465	11.82
1979	$ 4,417,924	47.5	106	100.00%	$ 4,417,924	0.7508	$ 3,316,978	11.21
1978	$ 2,783,967	48.5	108	100.00%	$ 2,783,967	0.7595	$ 2,114,423	10.82
1977	$ 3,304,874	49.5	110	100.00%	$ 3,304,874	0.7680	$ 2,538,143	10.44
1976	$ 2,176,706	50.5	112	100.00%	$ 2,176,706	0.7762	$ 1,689,559	10.07
1975	$ 1,903,052	51.5	114	100.00%	$ 1,903,052	0.7842	$ 1,492,373	9.71
1974	$ 2,499,356	52.5	117	100.00%	$ 2,499,356	0.7958	$ 1,988,988	9.19
1973	$ 2,375,024	53.5	119	100.00%	$ 2,375,024	0.8033	$ 1,907,857	8.85
1972	$ 1,546,172	54.5	121	100.00%	$ 1,546,172	0.8106	$ 1,253,327	8.52
1971	$ 1,053,967	55.5	123	100.00%	$ 1,053,967	0.8177	$ 861,829	8.20
1970	$ 1,741,877	56.5	126	100.00%	$ 1,741,877	0.8281	$ 1,442,448	7.74
1969	$ 1,575,722	57.5	128	100.00%	$ 1,575,722	0.8347	$ 1,315,255	7.44
1968	$ 1,485,177	58.5	130	100.00%	$ 1,485,177	0.8413	$ 1,249,479	7.14
1967	$ 1,188,222	59.5	132	100.00%	$ 1,188,222	0.8477	$ 1,007,256	6.85
1966	$ 1,106,057	60.5	134	100.00%	$ 1,106,057	0.8539	$ 944,462	6.57
1965	$ 896,718	61.5	137	100.00%	$ 896,718	0.8632	$ 774,047	6.16
1964	$ 737,350	62.5	139	100.00%	$ 737,350	0.8692	$ 640,905	5.89
1963	$ 617,519	63.5	141	100.00%	$ 617,519	0.8752	$ 540,452	5.62
1962	$ 502,620	64.5	143	100.00%	$ 502,620	0.8811	$ 442,858	5.35
1961	$ 381,800	65.5	146	100.00%	$ 381,800	0.8899	$ 339,764	4.95
1960	$ 329,750	66.5	148	100.00%	$ 329,750	0.8958	$ 295,390	4.69
1959	$ 284,057	67.5	150	100.00%	$ 284,057	0.9016	$ 256,106	4.43
1958	$ 164,037	68.5	152	100.00%	$ 164,037	0.9074	$ 148,847	4.17
1957	$ 111,000	69.5	154	100.00%	$ 111,000	0.9132	$ 101,365	3.91
1956	$ 79,759	70.5	157	100.00%	$ 79,759	0.9219	$ 73,530	3.51
1955	$ 54,089	71.5	159	100.00%	$ 54,089	0.9277	$ 50,179	3.25
1954	$ 24,979	72.5	161	100.00%	$ 24,979	0.9334	$ 23,315	3.00
1953	$ 15,509	73.5	163	100.00%	$ 15,509	0.9391	$ 14,564	2.74
1952	$ 1,476,667	74.5	166	100.00%	$ 1,476,667	0.9476	$ 1,399,290	2.36
1951	$ 19,454	75.5	168	100.00%	$ 19,454	0.9532	$ 18,544	2.11
1950	$ 25,469	76.5	170	100.00%	$ 25,469	0.9587	$ 24,417	1.86
1949	$ 17,692	77.5	172	100.00%	$ 17,692	0.9641	$ 17,057	1.62
1948	$ 19,487	78.5	174	100.00%	$ 19,487	0.9695	$ 18,893	1.37
1947	$ 15,798	79.5	177	100.00%	$ 15,798	0.9774	$ 15,441	1.02
1946	$ 14,473	80.5	179	100.00%	$ 14,473	0.9825	$ 14,220	0.79
1945	$ 8,342	81.5	181	100.00%	$ 8,342	0.9876	$ 8,239	0.56
1944	$ 4,922	82.5	183	100.00%	$ 4,922	0.9923	$ 4,884	0.35
1943	$ 2,912	83.5	186	100.00%	$ 2,912	1.0000	$ 2,912	0.00

1942	$	3,854	84.5	188	100.00%	$	3,854	1.0000	$	3,854	0.00
1941	$	5,821	85.5	190	100.00%	$	5,821	1.0000	$	5,821	0.00
1940	$	5,622	86.5	192	100.00%	$	5,622	1.0000	$	5,622	0.00
1939	$	5,042	87.5	194	100.00%	$	5,042	1.0000	$	5,042	0.00
1938	$	1,209	88.5	197	100.00%	$	1,209	1.0000	$	1,209	0.00
1937	$	-	89.5	199	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	201	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	203	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	206	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	208	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	210	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	212	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	214	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	217	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	219	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	221	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	223	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	226	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	228	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	230	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	232	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	234	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	237	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	239	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	241	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	243	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	246	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	248	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	250	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	252	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	254	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	257	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	259	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	261	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	263	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	266	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	268	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	270	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	272	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	274	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	277	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	279	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	281	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	283	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	286	100.00%	$	-	1.0000	$	-	0.00
1897	$	-	129.5	288	100.00%	$	-	1.0000	$	-	0.00
1896	$	-	130.5	290	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	292	100.00%	$	-	1.0000	$	-	0.00
1894	$	-	132.5	294	100.00%	$	-	1.0000	$	-	0.00
1893	$	-	133.5	297	100.00%	$	-	1.0000	$	-	0.00
1892	$	-	134.5	299	100.00%	$	-	1.0000	$	-	0.00

1891	$ -	135.5	301	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	303	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	306	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	308	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	310	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	312	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	314	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	317	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	319	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	321	100.00%	$ -	1.0000	$ -	0.00
Total	$ 1,799,933,111				$ 1,799,933,111		$ 421,733,628	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 421,733,628
Average Remaining Life	34.46
Theoretical Reserve %	23.43%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38100**
Plant Account **METERS**

Survivor Curve R2
Average Service Life 36
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 10,355,855	0.5	1	100.00%	$ 10,355,855	0.0091	$ 94,238	35.67
2025	$ 12,573,109	1.5	4	100.00%	$ 12,573,109	0.0361	$ 453,889	34.70
2024	$ 8,088,119	2.5	7	100.00%	$ 8,088,119	0.0629	$ 508,743	33.74
2023	$ 7,908,064	3.5	10	100.00%	$ 7,908,064	0.0894	$ 706,981	32.78
2022	$ 10,100,694	4.5	13	100.00%	$ 10,100,694	0.1157	$ 1,168,650	31.83
2021	$ 4,779,219	5.5	15	100.00%	$ 4,779,219	0.1331	$ 636,114	31.21
2020	$ 4,973,512	6.5	18	100.00%	$ 4,973,512	0.1589	$ 790,291	30.28
2019	$ 3,723,340	7.5	21	100.00%	$ 3,723,340	0.1845	$ 686,956	29.36
2018	$ 10,808,504	8.5	24	100.00%	$ 10,808,504	0.2098	$ 2,267,624	28.45
2017	$ 4,705,313	9.5	26	100.00%	$ 4,705,313	0.2265	$ 1,065,753	27.85
2016	$ 4,018,152	10.5	29	100.00%	$ 4,018,152	0.2513	$ 1,009,762	26.95
2015	$ 3,758,178	11.5	32	100.00%	$ 3,758,178	0.2757	$ 1,036,130	26.07
2014	$ 4,323,554	12.5	35	100.00%	$ 4,323,554	0.2999	$ 1,296,634	25.20
2013	$ 4,014,936	13.5	38	100.00%	$ 4,014,936	0.3237	$ 1,299,635	24.35
2012	$ 2,559,296	14.5	40	100.00%	$ 2,559,296	0.3394	$ 868,625	23.78
2011	$ 2,789,165	15.5	43	100.00%	$ 2,789,165	0.3627	$ 1,011,630	22.94
2010	$ 1,193,302	16.5	46	100.00%	$ 1,193,302	0.3855	$ 460,018	22.12
2009	$ 1,804,987	17.5	49	100.00%	$ 1,804,987	0.4081	$ 736,615	21.31
2008	$ 3,200,666	18.5	51	100.00%	$ 3,200,666	0.4229	$ 1,353,562	20.78
2007	$ 1,668,711	19.5	54	100.00%	$ 1,668,711	0.4447	$ 742,076	19.99
2006	$ 7,659,395	20.5	57	100.00%	$ 7,659,395	0.4662	$ 3,570,810	19.22
2005	$ 2,350,728	21.5	60	100.00%	$ 2,350,728	0.4873	$ 1,145,510	18.46
2004	$ 2,828,709	22.5	63	100.00%	$ 2,828,709	0.5080	$ 1,436,984	17.71
2003	$ 1,753,939	23.5	65	100.00%	$ 1,753,939	0.5215	$ 914,679	17.23
2002	$ 2,298,044	24.5	68	100.00%	$ 2,298,044	0.5414	$ 1,244,161	16.51
2001	$ 2,521,907	25.5	71	100.00%	$ 2,521,907	0.5609	$ 1,414,538	15.81
2000	$ 2,001,767	26.5	74	100.00%	$ 2,001,767	0.5799	$ 1,160,825	15.12
1999	$ 1,887,097	27.5	76	100.00%	$ 1,887,097	0.5923	$ 1,117,728	14.68
1998	$ 2,361,774	28.5	79	100.00%	$ 2,361,774	0.6105	$ 1,441,863	14.02
1997	$ 2,031,917	29.5	82	100.00%	$ 2,031,917	0.6282	$ 1,276,450	13.38
1996	$ 1,903,230	30.5	85	100.00%	$ 1,903,230	0.6453	$ 1,228,154	12.77

1995	$	1,445,042	31.5	88	100.00%	$	1,445,042	0.6620	$ 956,618	12.17
1994	$	3,113,717	32.5	90	100.00%	$	3,113,717	0.6728	$ 2,094,909	11.78
1993	$	1,933,184	33.5	93	100.00%	$	1,933,184	0.6886	$ 1,331,190	11.21
1992	$	1,862,608	34.5	96	100.00%	$	1,862,608	0.7039	$ 1,311,090	10.66
1991	$	1,605,631	35.5	99	100.00%	$	1,605,631	0.7186	$ 1,153,807	10.13
1990	$	1,469,069	36.5	101	100.00%	$	1,469,069	0.7281	$ 1,069,629	9.79
1989	$	1,099,151	37.5	104	100.00%	$	1,099,151	0.7419	$ 815,460	9.29
1988	$	923,997	38.5	107	100.00%	$	923,997	0.7552	$ 697,803	8.81
1987	$	814,930	39.5	110	100.00%	$	814,930	0.7680	$ 625,866	8.35
1986	$	820,140	40.5	113	100.00%	$	820,140	0.7803	$ 639,955	7.91
1985	$	846,396	41.5	115	100.00%	$	846,396	0.7882	$ 667,130	7.62
1984	$	386,973	42.5	118	100.00%	$	386,973	0.7996	$ 309,424	7.21
1983	$	114,453	43.5	121	100.00%	$	114,453	0.8106	$ 92,775	6.82
1982	$	291,105	44.5	124	100.00%	$	291,105	0.8212	$ 239,056	6.44
1981	$	1,541,420	45.5	126	100.00%	$	1,541,420	0.8281	$ 1,276,450	6.19
1980	$	1,295,909	46.5	129	100.00%	$	1,295,909	0.8380	$ 1,085,971	5.83
1979	$	290,025	47.5	132	100.00%	$	290,025	0.8477	$ 245,854	5.48
1978	$	134,550	48.5	135	100.00%	$	134,550	0.8570	$ 115,309	5.15
1977	$	80,542	49.5	138	100.00%	$	80,542	0.8662	$ 69,766	4.82
1976	$	61,922	50.5	140	100.00%	$	61,922	0.8722	$ 54,008	4.60
1975	$	125,540	51.5	143	100.00%	$	125,540	0.8811	$ 110,613	4.28
1974	$	127,884	52.5	146	100.00%	$	127,884	0.8899	$ 113,804	3.96
1973	$	197,868	53.5	149	100.00%	$	197,868	0.8987	$ 177,824	3.65
1972	$	360,558	54.5	151	100.00%	$	360,558	0.9045	$ 326,125	3.44
1971	$	337,939	55.5	154	100.00%	$	337,939	0.9132	$ 308,606	3.12
1970	$	460,102	56.5	157	100.00%	$	460,102	0.9219	$ 424,168	2.81
1969	$	531,591	57.5	160	100.00%	$	531,591	0.9305	$ 494,646	2.50
1968	$	393,488	58.5	163	100.00%	$	393,488	0.9391	$ 369,524	2.19
1967	$	301,872	59.5	165	100.00%	$	301,872	0.9448	$ 285,208	1.99
1966	$	348,624	60.5	168	100.00%	$	348,624	0.9532	$ 332,308	1.68
1965	$	227,212	61.5	171	100.00%	$	227,212	0.9614	$ 218,442	1.39
1964	$	127,167	62.5	174	100.00%	$	127,167	0.9695	$ 123,289	1.10
1963	$	60,934	63.5	176	100.00%	$	60,934	0.9748	$ 59,399	0.91
1962	$	52,821	64.5	179	100.00%	$	52,821	0.9825	$ 51,897	0.63
1961	$	31,936	65.5	182	100.00%	$	31,936	0.9900	$ 31,616	0.36
1960	$	12,995	66.5	185	100.00%	$	12,995	1.0000	$ 12,995	0.00
1959	$	6,668	67.5	188	100.00%	$	6,668	1.0000	$ 6,668	0.00
1958	$	9,449	68.5	190	100.00%	$	9,449	1.0000	$ 9,449	0.00
1957	$	3,771	69.5	193	100.00%	$	3,771	1.0000	$ 3,771	0.00
1956	$	6,387	70.5	196	100.00%	$	6,387	1.0000	$ 6,387	0.00
1955	$	3,509	71.5	199	100.00%	$	3,509	1.0000	$ 3,509	0.00
1954	$	1,449	72.5	201	100.00%	$	1,449	1.0000	$ 1,449	0.00
1953	$	3,740	73.5	204	100.00%	$	3,740	1.0000	$ 3,740	0.00
1952	$	4,439	74.5	207	100.00%	$	4,439	1.0000	$ 4,439	0.00
1951	$	2,803	75.5	210	100.00%	$	2,803	1.0000	$ 2,803	0.00
1950	$	1,998	76.5	213	100.00%	$	1,998	1.0000	$ 1,998	0.00
1949	$	1,638	77.5	215	100.00%	$	1,638	1.0000	$ 1,638	0.00
1948	$	278	78.5	218	100.00%	$	278	1.0000	$ 278	0.00
1947	$	-	79.5	221	100.00%	$	-	1.0000	$ -	0.00

1946	$	-	80.5	224	100.00%	$	-	1.0000	$	-	0.00
1945	$	-	81.5	226	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	229	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	232	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	235	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	238	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	240	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	243	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	246	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	249	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	251	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	254	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	257	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	260	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	263	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	265	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	268	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	271	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	274	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	276	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	279	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	282	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	285	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	288	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	290	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	293	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	296	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	299	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	301	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	304	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	307	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	310	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	313	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	315	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	318	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	321	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	324	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	326	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	329	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	332	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	335	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	338	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	340	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	343	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	346	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	349	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	351	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	354	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	357	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	360	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	363	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	365	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	368	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	371	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	374	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	376	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	379	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	382	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	385	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	388	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	390	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	393	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	396	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	399	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	401	100.00%	$ -	1.0000	$ -	0.00
Total	$160,820,610				$160,820,610		$ 52,484,291	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 52,484,291
Average Remaining Life	24.25
Theoretical Reserve %	32.64%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38110**
Plant Account **METERS - ERTS**

Survivor Curve S3
Average Service Life 17
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 5,182,232	0.5	3	100.00%	$ 5,182,232	0.0300	$ 155,467	16.49
2025	$ 985,737	1.5	9	100.00%	$ 985,737	0.0900	$ 88,716	15.47
2024	$ 2,843,622	2.5	15	100.00%	$ 2,843,622	0.1499	$ 426,259	14.45
2023	$ 3,460,545	3.5	21	100.00%	$ 3,460,545	0.2099	$ 726,368	13.43
2022	$ 2,442,480	4.5	26	100.00%	$ 2,442,480	0.2598	$ 634,556	12.58
2021	$ 2,942,654	5.5	32	100.00%	$ 2,942,654	0.3192	$ 939,295	11.57
2020	$ 3,016,232	6.5	38	100.00%	$ 3,016,232	0.3778	$ 1,139,532	10.58
2019	$ 2,537,648	7.5	44	100.00%	$ 2,537,648	0.4349	$ 1,103,623	9.61
2018	$ 1,455,239	8.5	50	100.00%	$ 1,455,239	0.4896	$ 712,485	8.68
2017	$ 2,070,928	9.5	56	100.00%	$ 2,070,928	0.5413	$ 1,120,993	7.80
2016	$ 882,348	10.5	62	100.00%	$ 882,348	0.5893	$ 519,968	6.98
2015	$ 1,085,289	11.5	68	100.00%	$ 1,085,289	0.6332	$ 687,205	6.24
2014	$ 249,378	12.5	74	100.00%	$ 249,378	0.6731	$ 167,856	5.56
2013	$ 1,326,472	13.5	79	100.00%	$ 1,326,472	0.7031	$ 932,643	5.05
2012	$ 2,595,357	14.5	85	100.00%	$ 2,595,357	0.7357	$ 1,909,404	4.49
2011	$ 174,668	15.5	91	100.00%	$ 174,668	0.7647	$ 133,568	4.00
2010	$ 2,660,439	16.5	97	100.00%	$ 2,660,439	0.7905	$ 2,103,077	3.56
2009	$ 442,179	17.5	103	100.00%	$ 442,179	0.8135	$ 359,713	3.17
2008	$ 412,679	18.5	109	100.00%	$ 412,679	0.8341	$ 344,216	2.82
2007	$ 1,255,275	19.5	115	100.00%	$ 1,255,275	0.8526	$ 1,070,247	2.51
2006	$ 1,066,120	20.5	121	100.00%	$ 1,066,120	0.8692	$ 926,672	2.22
2005	$ 991,205	21.5	126	100.00%	$ 991,205	0.8818	$ 874,045	2.01
2004	$ 2,333,320	22.5	132	100.00%	$ 2,333,320	0.8957	$ 2,089,955	1.77
2003	$ 587,775	23.5	138	100.00%	$ 587,775	0.9085	$ 533,994	1.56
2002	$ 1,381,276	24.5	144	100.00%	$ 1,381,276	0.9202	$ 1,271,050	1.36
2001	$ 448,550	25.5	150	100.00%	$ 448,550	0.9310	$ 417,600	1.17
2000	$ 77,483	26.5	156	100.00%	$ 77,483	0.9411	$ 72,919	1.00
1999	$ 28,486	27.5	162	100.00%	$ 28,486	0.9505	$ 27,076	0.84
1998	$ -	28.5	168	100.00%	$ -	0.9594	$ -	0.69
1997	$ -	29.5	174	100.00%	$ -	0.9677	$ -	0.55
1996	$ -	30.5	179	100.00%	$ -	0.9744	$ -	0.44

1995	$	-	31.5	185	100.00%	$	-	0.9819	$	-	0.31
1994	$	-	32.5	191	100.00%	$	-	0.9950	$	-	0.09
1993	$	425	33.5	197	100.00%	$	425	1.0000	$	425	0.00
1992	$	212	34.5	203	100.00%	$	212	1.0000	$	212	0.00
1991	$	2,630	35.5	209	100.00%	$	2,630	1.0000	$	2,630	0.00
1990	$	-	36.5	215	100.00%	$	-	1.0000	$	-	0.00
1989	$	1,392	37.5	221	100.00%	$	1,392	1.0000	$	1,392	0.00
1988	$	2,865	38.5	226	100.00%	$	2,865	1.0000	$	2,865	0.00
1987	$	-	39.5	232	100.00%	$	-	1.0000	$	-	0.00
1986	$	6,846	40.5	238	100.00%	$	6,846	1.0000	$	6,846	0.00
1985	$	-	41.5	244	100.00%	$	-	1.0000	$	-	0.00
1984	$	-	42.5	250	100.00%	$	-	1.0000	$	-	0.00
1983	$	-	43.5	256	100.00%	$	-	1.0000	$	-	0.00
1982	$	-	44.5	262	100.00%	$	-	1.0000	$	-	0.00
1981	$	-	45.5	268	100.00%	$	-	1.0000	$	-	0.00
1980	$	-	46.5	274	100.00%	$	-	1.0000	$	-	0.00
1979	$	-	47.5	279	100.00%	$	-	1.0000	$	-	0.00
1978	$	-	48.5	285	100.00%	$	-	1.0000	$	-	0.00
1977	$	-	49.5	291	100.00%	$	-	1.0000	$	-	0.00
1976	$	-	50.5	297	100.00%	$	-	1.0000	$	-	0.00
1975	$	-	51.5	303	100.00%	$	-	1.0000	$	-	0.00
1974	$	-	52.5	309	100.00%	$	-	1.0000	$	-	0.00
1973	$	-	53.5	315	100.00%	$	-	1.0000	$	-	0.00
1972	$	-	54.5	321	100.00%	$	-	1.0000	$	-	0.00
1971	$	-	55.5	326	100.00%	$	-	1.0000	$	-	0.00
1970	$	-	56.5	332	100.00%	$	-	1.0000	$	-	0.00
1969	$	-	57.5	338	100.00%	$	-	1.0000	$	-	0.00
1968	$	-	58.5	344	100.00%	$	-	1.0000	$	-	0.00
1967	$	-	59.5	350	100.00%	$	-	1.0000	$	-	0.00
1966	$	-	60.5	356	100.00%	$	-	1.0000	$	-	0.00
1965	$	-	61.5	362	100.00%	$	-	1.0000	$	-	0.00
1964	$	-	62.5	368	100.00%	$	-	1.0000	$	-	0.00
1963	$	-	63.5	374	100.00%	$	-	1.0000	$	-	0.00
1962	$	-	64.5	379	100.00%	$	-	1.0000	$	-	0.00
1961	$	-	65.5	385	100.00%	$	-	1.0000	$	-	0.00
1960	$	-	66.5	391	100.00%	$	-	1.0000	$	-	0.00
1959	$	-	67.5	397	100.00%	$	-	1.0000	$	-	0.00
1958	$	-	68.5	403	100.00%	$	-	1.0000	$	-	0.00
1957	$	-	69.5	409	100.00%	$	-	0.0000	$	-	17.00
1956	$	-	70.5	415	100.00%	$	-	0.0000	$	-	17.00
1955	$	-	71.5	421	100.00%	$	-	0.0000	$	-	17.00
1954	$	-	72.5	426	100.00%	$	-	0.0000	$	-	17.00
1953	$	-	73.5	432	100.00%	$	-	0.0000	$	-	17.00
1952	$	-	74.5	438	100.00%	$	-	0.0000	$	-	17.00
1951	$	-	75.5	444	100.00%	$	-	0.0000	$	-	17.00
1950	$	-	76.5	450	100.00%	$	-	0.0000	$	-	17.00
1949	$	-	77.5	456	100.00%	$	-	0.0000	$	-	17.00
1948	$	-	78.5	462	100.00%	$	-	0.0000	$	-	17.00
1947	$	-	79.5	468	100.00%	$	-	0.0000	$	-	17.00

1946	$	-	80.5	474	100.00%	$	-	0.0000	$	-	17.00
1945	$	-	81.5	479	100.00%	$	-	0.0000	$	-	17.00
1944	$	-	82.5	485	100.00%	$	-	0.0000	$	-	17.00
1943	$	-	83.5	491	100.00%	$	-	0.0000	$	-	17.00
1942	$	-	84.5	497	100.00%	$	-	0.0000	$	-	17.00
1941	$	-	85.5	503	100.00%	$	-	0.0000	$	-	17.00
1940	$	-	86.5	509	100.00%	$	-	0.0000	$	-	17.00
1939	$	-	87.5	515	100.00%	$	-	0.0000	$	-	17.00
1938	$	-	88.5	521	100.00%	$	-	0.0000	$	-	17.00
1937	$	-	89.5	526	100.00%	$	-	0.0000	$	-	17.00
1936	$	-	90.5	532	100.00%	$	-	0.0000	$	-	17.00
1935	$	-	91.5	538	100.00%	$	-	0.0000	$	-	17.00
1934	$	-	92.5	544	100.00%	$	-	0.0000	$	-	17.00
1933	$	-	93.5	550	100.00%	$	-	0.0000	$	-	17.00
1932	$	-	94.5	556	100.00%	$	-	0.0000	$	-	17.00
1931	$	-	95.5	562	100.00%	$	-	0.0000	$	-	17.00
1930	$	-	96.5	568	100.00%	$	-	0.0000	$	-	17.00
1929	$	-	97.5	574	100.00%	$	-	0.0000	$	-	17.00
1928	$	-	98.5	579	100.00%	$	-	0.0000	$	-	17.00
1927	$	-	99.5	585	100.00%	$	-	0.0000	$	-	17.00
1926	$	-	100.5	591	100.00%	$	-	0.0000	$	-	17.00
1925	$	-	101.5	597	100.00%	$	-	0.0000	$	-	17.00
1924	$	-	102.5	603	100.00%	$	-	0.0000	$	-	17.00
1923	$	-	103.5	609	100.00%	$	-	0.0000	$	-	17.00
1922	$	-	104.5	615	100.00%	$	-	0.0000	$	-	17.00
1921	$	-	105.5	621	100.00%	$	-	0.0000	$	-	17.00
1920	$	-	106.5	626	100.00%	$	-	0.0000	$	-	17.00
1919	$	-	107.5	632	100.00%	$	-	0.0000	$	-	17.00
1918	$	-	108.5	638	100.00%	$	-	0.0000	$	-	17.00
1917	$	-	109.5	644	100.00%	$	-	0.0000	$	-	17.00
1916	$	-	110.5	650	100.00%	$	-	0.0000	$	-	17.00
1915	$	-	111.5	656	100.00%	$	-	0.0000	$	-	17.00
1914	$	-	112.5	662	100.00%	$	-	0.0000	$	-	17.00
1913	$	-	113.5	668	100.00%	$	-	0.0000	$	-	17.00
1912	$	-	114.5	674	100.00%	$	-	0.0000	$	-	17.00
1911	$	-	115.5	679	100.00%	$	-	0.0000	$	-	17.00
1910	$	-	116.5	685	100.00%	$	-	0.0000	$	-	17.00
1909	$	-	117.5	691	100.00%	$	-	0.0000	$	-	17.00
1908	$	-	118.5	697	100.00%	$	-	0.0000	$	-	17.00
1907	$	-	119.5	703	100.00%	$	-	0.0000	$	-	17.00
1906	$	-	120.5	709	100.00%	$	-	0.0000	$	-	17.00
1905	$	-	121.5	715	100.00%	$	-	0.0000	$	-	17.00
1904	$	-	122.5	721	100.00%	$	-	0.0000	$	-	17.00
1903	$	-	123.5	726	100.00%	$	-	0.0000	$	-	17.00
1902	$	-	124.5	732	100.00%	$	-	0.0000	$	-	17.00
1901	$	-	125.5	738	100.00%	$	-	0.0000	$	-	17.00
1900	$	-	126.5	744	100.00%	$	-	0.0000	$	-	17.00
1899	$	-	127.5	750	100.00%	$	-	0.0000	$	-	17.00
1898	$	-	128.5	756	100.00%	$	-	0.0000	$	-	17.00

1897	$ -	129.5	762	100.00%	$ -	0.0000	$ -	17.00
1896	$ -	130.5	768	100.00%	$ -	0.0000	$ -	17.00
1895	$ -	131.5	774	100.00%	$ -	0.0000	$ -	17.00
1894	$ -	132.5	779	100.00%	$ -	0.0000	$ -	17.00
1893	$ -	133.5	785	100.00%	$ -	0.0000	$ -	17.00
1892	$ -	134.5	791	100.00%	$ -	0.0000	$ -	17.00
1891	$ -	135.5	797	100.00%	$ -	0.0000	$ -	17.00
1890	$ -	136.5	803	100.00%	$ -	0.0000	$ -	17.00
1889	$ -	137.5	809	100.00%	$ -	0.0000	$ -	17.00
1888	$ -	138.5	815	100.00%	$ -	0.0000	$ -	17.00
1887	$ -	139.5	821	100.00%	$ -	0.0000	$ -	17.00
1886	$ -	140.5	826	100.00%	$ -	0.0000	$ -	17.00
1885	$ -	141.5	832	100.00%	$ -	0.0000	$ -	17.00
1884	$ -	142.5	838	100.00%	$ -	0.0000	$ -	17.00
1883	$ -	143.5	844	100.00%	$ -	0.0000	$ -	17.00
1882	$ -	144.5	850	100.00%	$ -	0.0000	$ -	17.00
Total	$ 44,949,985				$ 44,949,985		$ 21,502,872	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 21,502,872
Average Remaining Life	8.87
Theoretical Reserve %	47.84%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38200**
Plant Account **METER INSTALLATIONS**

Survivor Curve R2
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 6,291,671	0.5	1	100.00%	$ 6,291,671	0.0091	$ 57,254	44.59
2025	$ 5,585,552	1.5	3	100.00%	$ 5,585,552	0.0271	$ 151,368	43.78
2024	$ 8,853,448	2.5	6	100.00%	$ 8,853,448	0.0540	$ 478,086	42.57
2023	$ 13,763,946	3.5	8	100.00%	$ 13,763,946	0.0717	$ 986,875	41.77
2022	$ 8,971,994	4.5	10	100.00%	$ 8,971,994	0.0894	$ 802,096	40.98
2021	$ 6,778,518	5.5	12	100.00%	$ 6,778,518	0.1070	$ 725,301	40.19
2020	$ 2,630,765	6.5	14	100.00%	$ 2,630,765	0.1244	$ 327,267	39.40
2019	$ 4,731,407	7.5	17	100.00%	$ 4,731,407	0.1503	$ 711,131	38.24
2018	$ 5,863,480	8.5	19	100.00%	$ 5,863,480	0.1675	$ 982,133	37.46
2017	$ 4,634,322	9.5	21	100.00%	$ 4,634,322	0.1845	$ 855,032	36.70
2016	$ 4,055,652	10.5	23	100.00%	$ 4,055,652	0.2014	$ 816,808	35.94
2015	$ 5,107,555	11.5	26	100.00%	$ 5,107,555	0.2265	$ 1,156,861	34.81
2014	$ 3,554,412	12.5	28	100.00%	$ 3,554,412	0.2430	$ 863,722	34.07
2013	$ 4,109,924	13.5	30	100.00%	$ 4,109,924	0.2595	$ 1,066,525	33.32
2012	$ 3,687,281	14.5	32	100.00%	$ 3,687,281	0.2757	$ 1,016,583	32.59
2011	$ 3,359,321	15.5	34	100.00%	$ 3,359,321	0.2919	$ 980,586	31.86
2010	$ 1,029,523	16.5	37	100.00%	$ 1,029,523	0.3158	$ 325,123	30.79
2009	$ 3,183,544	17.5	39	100.00%	$ 3,183,544	0.3316	$ 1,055,663	30.08
2008	$ 4,783,417	18.5	41	100.00%	$ 4,783,417	0.3472	$ 1,660,802	29.38
2007	$ 8,755,062	19.5	43	100.00%	$ 8,755,062	0.3627	$ 3,175,461	28.68
2006	$ 2,028,451	20.5	46	100.00%	$ 2,028,451	0.3855	$ 781,968	27.65
2005	$ 1,698,969	21.5	48	100.00%	$ 1,698,969	0.4006	$ 680,607	26.97
2004	$ 1,483,602	22.5	50	100.00%	$ 1,483,602	0.4155	$ 616,436	26.30
2003	$ 1,816,916	23.5	52	100.00%	$ 1,816,916	0.4302	$ 781,637	25.64
2002	$ 1,362,506	24.5	54	100.00%	$ 1,362,506	0.4447	$ 605,906	24.99
2001	$ 2,043,776	25.5	57	100.00%	$ 2,043,776	0.4662	$ 952,808	24.02
2000	$ 2,144,308	26.5	59	100.00%	$ 2,144,308	0.4803	$ 1,029,911	23.39
1999	$ 2,166,743	27.5	61	100.00%	$ 2,166,743	0.4942	$ 1,070,804	22.76
1998	$ 2,196,063	28.5	63	100.00%	$ 2,196,063	0.5080	$ 1,115,600	22.14
1997	$ 2,177,854	29.5	66	100.00%	$ 2,177,854	0.5282	$ 1,150,343	21.23
1996	$ 1,694,278	30.5	68	100.00%	$ 1,694,278	0.5414	$ 917,282	20.64

1995	$ 1,699,625	31.5	70	100.00%	$ 1,699,625	0.5544	$ 942,272	20.05
1994	$ 1,461,073	32.5	72	100.00%	$ 1,461,073	0.5673	$ 828,867	19.47
1993	$ 1,053,176	33.5	74	100.00%	$ 1,053,176	0.5799	$ 610,737	18.90
1992	$ 1,299,002	34.5	77	100.00%	$ 1,299,002	0.5984	$ 777,323	18.07
1991	$ 1,372,854	35.5	79	100.00%	$ 1,372,854	0.6105	$ 838,127	17.53
1990	$ 1,393,475	36.5	81	100.00%	$ 1,393,475	0.6223	$ 867,159	17.00
1989	$ 1,130,353	37.5	83	100.00%	$ 1,130,353	0.6339	$ 716,531	16.47
1988	$ 1,042,471	38.5	86	100.00%	$ 1,042,471	0.6510	$ 678,648	15.71
1987	$ 805,381	39.5	88	100.00%	$ 805,381	0.6620	$ 533,162	15.21
1986	$ 741,893	40.5	90	100.00%	$ 741,893	0.6728	$ 499,146	14.72
1985	$ 708,974	41.5	92	100.00%	$ 708,974	0.6834	$ 484,513	14.25
1984	$ 524,405	42.5	94	100.00%	$ 524,405	0.6938	$ 363,832	13.78
1983	$ 558,922	43.5	97	100.00%	$ 558,922	0.7088	$ 396,164	13.10
1982	$ 551,135	44.5	99	100.00%	$ 551,135	0.7186	$ 396,046	12.66
1981	$ 664,339	45.5	101	100.00%	$ 664,339	0.7281	$ 483,705	12.24
1980	$ 594,766	46.5	103	100.00%	$ 594,766	0.7374	$ 438,581	11.82
1979	$ 305,771	47.5	106	100.00%	$ 305,771	0.7508	$ 229,573	11.21
1978	$ 94,947	48.5	108	100.00%	$ 94,947	0.7595	$ 72,112	10.82
1977	$ 80,088	49.5	110	100.00%	$ 80,088	0.7680	$ 61,508	10.44
1976	$ 47,534	50.5	112	100.00%	$ 47,534	0.7762	$ 36,896	10.07
1975	$ 95,924	51.5	114	100.00%	$ 95,924	0.7842	$ 75,224	9.71
1974	$ 147,542	52.5	117	100.00%	$ 147,542	0.7958	$ 117,414	9.19
1973	$ 199,215	53.5	119	100.00%	$ 199,215	0.8033	$ 160,030	8.85
1972	$ 98,298	54.5	121	100.00%	$ 98,298	0.8106	$ 79,680	8.52
1971	$ 115,332	55.5	123	100.00%	$ 115,332	0.8177	$ 94,307	8.20
1970	$ -	56.5	126	100.00%	$ -	0.8281	$ -	7.74
1969	$ -	57.5	128	100.00%	$ -	0.8347	$ -	7.44
1968	$ -	58.5	130	100.00%	$ -	0.8413	$ -	7.14
1967	$ -	59.5	132	100.00%	$ -	0.8477	$ -	6.85
1966	$ -	60.5	134	100.00%	$ -	0.8539	$ -	6.57
1965	$ -	61.5	137	100.00%	$ -	0.8632	$ -	6.16
1964	$ -	62.5	139	100.00%	$ -	0.8692	$ -	5.89
1963	$ -	63.5	141	100.00%	$ -	0.8752	$ -	5.62
1962	$ -	64.5	143	100.00%	$ -	0.8811	$ -	5.35
1961	$ -	65.5	146	100.00%	$ -	0.8899	$ -	4.95
1960	$ -	66.5	148	100.00%	$ -	0.8958	$ -	4.69
1959	$ -	67.5	150	100.00%	$ -	0.9016	$ -	4.43
1958	$ -	68.5	152	100.00%	$ -	0.9074	$ -	4.17
1957	$ -	69.5	154	100.00%	$ -	0.9132	$ -	3.91
1956	$ -	70.5	157	100.00%	$ -	0.9219	$ -	3.51
1955	$ -	71.5	159	100.00%	$ -	0.9277	$ -	3.25
1954	$ -	72.5	161	100.00%	$ -	0.9334	$ -	3.00
1953	$ -	73.5	163	100.00%	$ -	0.9391	$ -	2.74
1952	$ -	74.5	166	100.00%	$ -	0.9476	$ -	2.36
1951	$ -	75.5	168	100.00%	$ -	0.9532	$ -	2.11
1950	$ -	76.5	170	100.00%	$ -	0.9587	$ -	1.86
1949	$ -	77.5	172	100.00%	$ -	0.9641	$ -	1.62
1948	$ -	78.5	174	100.00%	$ -	0.9695	$ -	1.37
1947	$ -	79.5	177	100.00%	$ -	0.9774	$ -	1.02

1946	$	-	80.5	179	100.00%	$	-	0.9825	$	-	0.79
1945	$	-	81.5	181	100.00%	$	-	0.9876	$	-	0.56
1944	$	-	82.5	183	100.00%	$	-	0.9923	$	-	0.35
1943	$	-	83.5	186	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	188	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	190	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	192	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	194	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	197	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	199	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	201	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	203	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	206	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	208	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	210	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	212	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	214	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	217	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	219	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	221	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	223	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	226	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	228	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	230	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	232	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	234	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	237	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	239	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	241	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	243	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	246	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	248	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	250	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	252	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	254	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	257	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	259	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	261	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	263	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	266	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	268	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	270	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	272	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	274	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	277	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	279	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	281	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	283	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	286	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	288	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	290	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	292	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	294	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	297	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	299	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	301	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	303	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	306	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	308	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	310	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	312	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	314	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	317	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	319	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	321	100.00%	$ -	1.0000	$ -	0.00
Total	$147,330,759				$147,330,759		$ 38,679,536	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 38,679,536
Average Remaining Life	33.19
Theoretical Reserve %	26.25%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38300**
Plant Account **HOUSE REGULATORS**

Survivor Curve R2
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0091	$ -	44.59
2025	$ 87,911	1.5	3	100.00%	$ 87,911	0.0271	$ 2,382	43.78
2024	$ 91,913	2.5	6	100.00%	$ 91,913	0.0540	$ 4,963	42.57
2023	$ 80,894	3.5	8	100.00%	$ 80,894	0.0717	$ 5,800	41.77
2022	$ 34,280	4.5	10	100.00%	$ 34,280	0.0894	$ 3,065	40.98
2021	$ 2,475	5.5	12	100.00%	$ 2,475	0.1070	$ 265	40.19
2020	$ 80,753	6.5	14	100.00%	$ 80,753	0.1244	$ 10,046	39.40
2019	$ 341	7.5	17	100.00%	$ 341	0.1503	$ 51	38.24
2018	$ 11,254	8.5	19	100.00%	$ 11,254	0.1675	$ 1,885	37.46
2017	$ 118,289	9.5	21	100.00%	$ 118,289	0.1845	$ 21,824	36.70
2016	$ 34,471	10.5	23	100.00%	$ 34,471	0.2014	$ 6,943	35.94
2015	$ 17,007	11.5	26	100.00%	$ 17,007	0.2265	$ 3,852	34.81
2014	$ 28,085	12.5	28	100.00%	$ 28,085	0.2430	$ 6,825	34.07
2013	$ 96,857	13.5	30	100.00%	$ 96,857	0.2595	$ 25,134	33.32
2012	$ 228,803	14.5	32	100.00%	$ 228,803	0.2757	$ 63,081	32.59
2011	$ 25,078	15.5	34	100.00%	$ 25,078	0.2919	$ 7,320	31.86
2010	$ 620,577	16.5	37	100.00%	$ 620,577	0.3158	$ 195,978	30.79
2009	$ 575,227	17.5	39	100.00%	$ 575,227	0.3316	$ 190,745	30.08
2008	$ 564,506	18.5	41	100.00%	$ 564,506	0.3472	$ 195,997	29.38
2007	$ 140,322	19.5	43	100.00%	$ 140,322	0.3627	$ 50,895	28.68
2006	$ 198,548	20.5	46	100.00%	$ 198,548	0.3855	$ 76,540	27.65
2005	$ 229,394	21.5	48	100.00%	$ 229,394	0.4006	$ 91,895	26.97
2004	$ 466,159	22.5	50	100.00%	$ 466,159	0.4155	$ 193,689	26.30
2003	$ 297,968	23.5	52	100.00%	$ 297,968	0.4302	$ 128,186	25.64
2002	$ 245,105	24.5	54	100.00%	$ 245,105	0.4447	$ 108,998	24.99
2001	$ 302,719	25.5	57	100.00%	$ 302,719	0.4662	$ 141,128	24.02
2000	$ 196,542	26.5	59	100.00%	$ 196,542	0.4803	$ 94,399	23.39
1999	$ 128,891	27.5	61	100.00%	$ 128,891	0.4942	$ 63,698	22.76
1998	$ 380,279	28.5	63	100.00%	$ 380,279	0.5080	$ 193,182	22.14
1997	$ 349,684	29.5	66	100.00%	$ 349,684	0.5282	$ 184,703	21.23
1996	$ 115,585	30.5	68	100.00%	$ 115,585	0.5414	$ 62,578	20.64

1995	$	252,294	31.5	70	100.00%	$	252,294	0.5544	$	139,872	20.05
1994	$	266,376	32.5	72	100.00%	$	266,376	0.5673	$	151,115	19.47
1993	$	159,482	33.5	74	100.00%	$	159,482	0.5799	$	92,484	18.90
1992	$	221,441	34.5	77	100.00%	$	221,441	0.5984	$	132,510	18.07
1991	$	132,504	35.5	79	100.00%	$	132,504	0.6105	$	80,893	17.53
1990	$	380,114	36.5	81	100.00%	$	380,114	0.6223	$	236,545	17.00
1989	$	324,190	37.5	83	100.00%	$	324,190	0.6339	$	205,504	16.47
1988	$	209,156	38.5	86	100.00%	$	209,156	0.6510	$	136,161	15.71
1987	$	168,538	39.5	88	100.00%	$	168,538	0.6620	$	111,572	15.21
1986	$	174,144	40.5	90	100.00%	$	174,144	0.6728	$	117,164	14.72
1985	$	227,383	41.5	92	100.00%	$	227,383	0.6834	$	155,393	14.25
1984	$	84,300	42.5	94	100.00%	$	84,300	0.6938	$	58,487	13.78
1983	$	92,146	43.5	97	100.00%	$	92,146	0.7088	$	65,313	13.10
1982	$	147,952	44.5	99	100.00%	$	147,952	0.7186	$	106,319	12.66
1981	$	184,277	45.5	101	100.00%	$	184,277	0.7281	$	134,172	12.24
1980	$	354,696	46.5	103	100.00%	$	354,696	0.7374	$	261,553	11.82
1979	$	159,662	47.5	106	100.00%	$	159,662	0.7508	$	119,874	11.21
1978	$	54,939	48.5	108	100.00%	$	54,939	0.7595	$	41,726	10.82
1977	$	66,133	49.5	110	100.00%	$	66,133	0.7680	$	50,790	10.44
1976	$	35,996	50.5	112	100.00%	$	35,996	0.7762	$	27,940	10.07
1975	$	56,388	51.5	114	100.00%	$	56,388	0.7842	$	44,219	9.71
1974	$	60,649	52.5	117	100.00%	$	60,649	0.7958	$	48,264	9.19
1973	$	56,632	53.5	119	100.00%	$	56,632	0.8033	$	45,493	8.85
1972	$	64,053	54.5	121	100.00%	$	64,053	0.8106	$	51,922	8.52
1971	$	74,788	55.5	123	100.00%	$	74,788	0.8177	$	61,154	8.20
1970	$	74,214	56.5	126	100.00%	$	74,214	0.8281	$	61,457	7.74
1969	$	49,266	57.5	128	100.00%	$	49,266	0.8347	$	41,123	7.44
1968	$	47,784	58.5	130	100.00%	$	47,784	0.8413	$	40,201	7.14
1967	$	58,077	59.5	132	100.00%	$	58,077	0.8477	$	49,232	6.85
1966	$	61,005	60.5	134	100.00%	$	61,005	0.8539	$	52,092	6.57
1965	$	59,299	61.5	137	100.00%	$	59,299	0.8632	$	51,187	6.16
1964	$	55,725	62.5	139	100.00%	$	55,725	0.8692	$	48,436	5.89
1963	$	14,471	63.5	141	100.00%	$	14,471	0.8752	$	12,665	5.62
1962	$	30,844	64.5	143	100.00%	$	30,844	0.8811	$	27,176	5.35
1961	$	9,266	65.5	146	100.00%	$	9,266	0.8899	$	8,246	4.95
1960	$	13,576	66.5	148	100.00%	$	13,576	0.8958	$	12,162	4.69
1959	$	5,077	67.5	150	100.00%	$	5,077	0.9016	$	4,577	4.43
1958	$	523	68.5	152	100.00%	$	523	0.9074	$	475	4.17
1957	$	4,430	69.5	154	100.00%	$	4,430	0.9132	$	4,045	3.91
1956	$	2,289	70.5	157	100.00%	$	2,289	0.9219	$	2,110	3.51
1955	$	-	71.5	159	100.00%	$	-	0.9277	$	-	3.25
1954	$	3,639	72.5	161	100.00%	$	3,639	0.9334	$	3,396	3.00
1953	$	3,325	73.5	163	100.00%	$	3,325	0.9391	$	3,122	2.74
1952	$	22,872	74.5	166	100.00%	$	22,872	0.9476	$	21,674	2.36
1951	$	-	75.5	168	100.00%	$	-	0.9532	$	-	2.11
1950	$	212	76.5	170	100.00%	$	212	0.9587	$	203	1.86
1949	$	-	77.5	172	100.00%	$	-	0.9641	$	-	1.62
1948	$	-	78.5	174	100.00%	$	-	0.9695	$	-	1.37
1947	$	-	79.5	177	100.00%	$	-	0.9774	$	-	1.02

1946	$	-	80.5	179	100.00%	$	-	0.9825	$	-	0.79
1945	$	-	81.5	181	100.00%	$	-	0.9876	$	-	0.56
1944	$	78	82.5	183	100.00%	$	78	0.9923	$	77	0.35
1943	$	-	83.5	186	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	188	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	190	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	192	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	194	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	197	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	199	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	201	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	203	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	206	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	208	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	210	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	212	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	214	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	217	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	219	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	221	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	223	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	226	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	228	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	230	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	232	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	234	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	237	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	239	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	241	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	243	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	246	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	248	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	250	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	252	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	254	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	257	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	259	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	261	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	263	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	266	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	268	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	270	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	272	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	274	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	277	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	279	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	281	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	283	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	286	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	288	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	290	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	292	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	294	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	297	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	299	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	301	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	303	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	306	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	308	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	310	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	312	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	314	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	317	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	319	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	321	100.00%	$ -	1.0000	$ -	0.00
Total	$ 10,274,123				$ 10,274,123		$ 5,256,142	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 5,256,142
Average Remaining Life	21.98
Theoretical Reserve %	51.16%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38400**
Plant Account **HOUSE REGULATOR INSTALLATIONS**

Survivor Curve R2
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0091	$ -	44.59
2025	$ 219,867	1.5	3	100.00%	$ 219,867	0.0271	$ 5,958	43.78
2024	$ 42,909	2.5	6	100.00%	$ 42,909	0.0540	$ 2,317	42.57
2023	$ 2,635	3.5	8	100.00%	$ 2,635	0.0717	$ 189	41.77
2022	$ 38,389	4.5	10	100.00%	$ 38,389	0.0894	$ 3,432	40.98
2021	$ 270,429	5.5	12	100.00%	$ 270,429	0.1070	$ 28,936	40.19
2020	$ 220,288	6.5	14	100.00%	$ 220,288	0.1244	$ 27,404	39.40
2019	$ 586,434	7.5	17	100.00%	$ 586,434	0.1503	$ 88,141	38.24
2018	$ 957,831	8.5	19	100.00%	$ 957,831	0.1675	$ 160,437	37.46
2017	$ 839,170	9.5	21	100.00%	$ 839,170	0.1845	$ 154,827	36.70
2016	$ 788,474	10.5	23	100.00%	$ 788,474	0.2014	$ 158,799	35.94
2015	$ 482,517	11.5	26	100.00%	$ 482,517	0.2265	$ 109,290	34.81
2014	$ 585,553	12.5	28	100.00%	$ 585,553	0.2430	$ 142,289	34.07
2013	$ 524,682	13.5	30	100.00%	$ 524,682	0.2595	$ 136,155	33.32
2012	$ 629,103	14.5	32	100.00%	$ 629,103	0.2757	$ 173,444	32.59
2011	$ 398,864	15.5	34	100.00%	$ 398,864	0.2919	$ 116,428	31.86
2010	$ 340,272	16.5	37	100.00%	$ 340,272	0.3158	$ 107,458	30.79
2009	$ 386,434	17.5	39	100.00%	$ 386,434	0.3316	$ 128,141	30.08
2008	$ 1,016,964	18.5	41	100.00%	$ 1,016,964	0.3472	$ 353,090	29.38
2007	$ 155,264	19.5	43	100.00%	$ 155,264	0.3627	$ 56,314	28.68
2006	$ 405,747	20.5	46	100.00%	$ 405,747	0.3855	$ 156,415	27.65
2005	$ 634,680	21.5	48	100.00%	$ 634,680	0.4006	$ 254,253	26.97
2004	$ 847,438	22.5	50	100.00%	$ 847,438	0.4155	$ 352,110	26.30
2003	$ 647,029	23.5	52	100.00%	$ 647,029	0.4302	$ 278,352	25.64
2002	$ 319,867	24.5	54	100.00%	$ 319,867	0.4447	$ 142,245	24.99
2001	$ 257,199	25.5	57	100.00%	$ 257,199	0.4662	$ 119,906	24.02
2000	$ 224,598	26.5	59	100.00%	$ 224,598	0.4803	$ 107,875	23.39
1999	$ 258,783	27.5	61	100.00%	$ 258,783	0.4942	$ 127,891	22.76
1998	$ 346,888	28.5	63	100.00%	$ 346,888	0.5080	$ 176,219	22.14
1997	$ 287,033	29.5	66	100.00%	$ 287,033	0.5282	$ 151,611	21.23
1996	$ 307,584	30.5	68	100.00%	$ 307,584	0.5414	$ 166,526	20.64

1995	$ 333,832	31.5	70	100.00%	$ 333,832	0.5544	$ 185,077	20.05
1994	$ 255,644	32.5	72	100.00%	$ 255,644	0.5673	$ 145,027	19.47
1993	$ 191,268	33.5	74	100.00%	$ 191,268	0.5799	$ 110,916	18.90
1992	$ 236,639	34.5	77	100.00%	$ 236,639	0.5984	$ 141,605	18.07
1991	$ 183,000	35.5	79	100.00%	$ 183,000	0.6105	$ 111,721	17.53
1990	$ 265,141	36.5	81	100.00%	$ 265,141	0.6223	$ 164,997	17.00
1989	$ 322,079	37.5	83	100.00%	$ 322,079	0.6339	$ 204,166	16.47
1988	$ 263,355	38.5	86	100.00%	$ 263,355	0.6510	$ 171,444	15.71
1987	$ 175,211	39.5	88	100.00%	$ 175,211	0.6620	$ 115,990	15.21
1986	$ 179,114	40.5	90	100.00%	$ 179,114	0.6728	$ 120,508	14.72
1985	$ 199,809	41.5	92	100.00%	$ 199,809	0.6834	$ 136,549	14.25
1984	$ 111,202	42.5	94	100.00%	$ 111,202	0.6938	$ 77,152	13.78
1983	$ 168,967	43.5	97	100.00%	$ 168,967	0.7088	$ 119,764	13.10
1982	$ 198,198	44.5	99	100.00%	$ 198,198	0.7186	$ 142,425	12.66
1981	$ 229,308	45.5	101	100.00%	$ 229,308	0.7281	$ 166,959	12.24
1980	$ 198,595	46.5	103	100.00%	$ 198,595	0.7374	$ 146,444	11.82
1979	$ 151,061	47.5	106	100.00%	$ 151,061	0.7508	$ 113,417	11.21
1978	$ 169,867	48.5	108	100.00%	$ 169,867	0.7595	$ 129,014	10.82
1977	$ 261,561	49.5	110	100.00%	$ 261,561	0.7680	$ 200,879	10.44
1976	$ 187,235	50.5	112	100.00%	$ 187,235	0.7762	$ 145,332	10.07
1975	$ 132,717	51.5	114	100.00%	$ 132,717	0.7842	$ 104,077	9.71
1974	$ 195,307	52.5	117	100.00%	$ 195,307	0.7958	$ 155,425	9.19
1973	$ 93,397	53.5	119	100.00%	$ 93,397	0.8033	$ 75,026	8.85
1972	$ 66,384	54.5	121	100.00%	$ 66,384	0.8106	$ 53,811	8.52
1971	$ 37,539	55.5	123	100.00%	$ 37,539	0.8177	$ 30,696	8.20
1970	$ -	56.5	126	100.00%	$ -	0.8281	$ -	7.74
1969	$ -	57.5	128	100.00%	$ -	0.8347	$ -	7.44
1968	$ -	58.5	130	100.00%	$ -	0.8413	$ -	7.14
1967	$ -	59.5	132	100.00%	$ -	0.8477	$ -	6.85
1966	$ -	60.5	134	100.00%	$ -	0.8539	$ -	6.57
1965	$ -	61.5	137	100.00%	$ -	0.8632	$ -	6.16
1964	$ -	62.5	139	100.00%	$ -	0.8692	$ -	5.89
1963	$ -	63.5	141	100.00%	$ -	0.8752	$ -	5.62
1962	$ -	64.5	143	100.00%	$ -	0.8811	$ -	5.35
1961	$ -	65.5	146	100.00%	$ -	0.8899	$ -	4.95
1960	$ -	66.5	148	100.00%	$ -	0.8958	$ -	4.69
1959	$ -	67.5	150	100.00%	$ -	0.9016	$ -	4.43
1958	$ -	68.5	152	100.00%	$ -	0.9074	$ -	4.17
1957	$ -	69.5	154	100.00%	$ -	0.9132	$ -	3.91
1956	$ -	70.5	157	100.00%	$ -	0.9219	$ -	3.51
1955	$ -	71.5	159	100.00%	$ -	0.9277	$ -	3.25
1954	$ -	72.5	161	100.00%	$ -	0.9334	$ -	3.00
1953	$ -	73.5	163	100.00%	$ -	0.9391	$ -	2.74
1952	$ -	74.5	166	100.00%	$ -	0.9476	$ -	2.36
1951	$ -	75.5	168	100.00%	$ -	0.9532	$ -	2.11
1950	$ -	76.5	170	100.00%	$ -	0.9587	$ -	1.86
1949	$ -	77.5	172	100.00%	$ -	0.9641	$ -	1.62
1948	$ -	78.5	174	100.00%	$ -	0.9695	$ -	1.37
1947	$ -	79.5	177	100.00%	$ -	0.9774	$ -	1.02

1946	$	-	80.5	179	100.00%	$	-	0.9825	$	-	0.79
1945	$	-	81.5	181	100.00%	$	-	0.9876	$	-	0.56
1944	$	-	82.5	183	100.00%	$	-	0.9923	$	-	0.35
1943	$	-	83.5	186	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	188	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	190	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	192	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	194	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	197	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	199	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	201	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	203	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	206	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	208	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	210	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	212	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	214	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	217	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	219	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	221	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	223	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	226	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	228	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	230	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	232	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	234	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	237	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	239	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	241	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	243	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	246	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	248	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	250	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	252	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	254	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	257	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	259	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	261	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	263	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	266	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	268	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	270	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	272	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	274	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	277	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	279	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	281	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	283	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	286	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	288	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	290	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	292	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	294	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	297	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	299	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	301	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	303	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	306	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	308	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	310	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	312	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	314	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	317	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	319	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	321	100.00%	$ -	1.0000	$ -	0.00
Total	$ 17,829,357				$ 17,829,357		$ 7,254,873	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 7,254,873
Average Remaining Life	26.69
Theoretical Reserve %	40.69%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38500**
Plant Account **INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT**

Survivor Curve R2
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ 1,001,850	0.5	1	100.00%	$ 1,001,850	0.0091	$ 9,117	44.59
2025	$ 120,912	1.5	3	100.00%	$ 120,912	0.0271	$ 3,277	43.78
2024	$ 1,050,935	2.5	6	100.00%	$ 1,050,935	0.0540	$ 56,751	42.57
2023	$ 76,265	3.5	8	100.00%	$ 76,265	0.0717	$ 5,468	41.77
2022	$ 9,405	4.5	10	100.00%	$ 9,405	0.0894	$ 841	40.98
2021	$ 1,048,261	5.5	12	100.00%	$ 1,048,261	0.1070	$ 112,164	40.19
2020	$ 2,184,293	6.5	14	100.00%	$ 2,184,293	0.1244	$ 271,726	39.40
2019	$ 1,608,365	7.5	17	100.00%	$ 1,608,365	0.1503	$ 241,737	38.24
2018	$ 1,284,324	8.5	19	100.00%	$ 1,284,324	0.1675	$ 215,124	37.46
2017	$ 1,491,699	9.5	21	100.00%	$ 1,491,699	0.1845	$ 275,218	36.70
2016	$ 2,981,082	10.5	23	100.00%	$ 2,981,082	0.2014	$ 600,390	35.94
2015	$ 3,542,683	11.5	26	100.00%	$ 3,542,683	0.2265	$ 802,418	34.81
2014	$ 655,431	12.5	28	100.00%	$ 655,431	0.2430	$ 159,270	34.07
2013	$ 345,561	13.5	30	100.00%	$ 345,561	0.2595	$ 89,673	33.32
2012	$ 609,917	14.5	32	100.00%	$ 609,917	0.2757	$ 168,154	32.59
2011	$ 1,456,712	15.5	34	100.00%	$ 1,456,712	0.2919	$ 425,214	31.86
2010	$ 607,719	16.5	37	100.00%	$ 607,719	0.3158	$ 191,918	30.79
2009	$ 558,659	17.5	39	100.00%	$ 558,659	0.3316	$ 185,251	30.08
2008	$ 880,796	18.5	41	100.00%	$ 880,796	0.3472	$ 305,812	29.38
2007	$ 530,470	19.5	43	100.00%	$ 530,470	0.3627	$ 192,402	28.68
2006	$ 917,068	20.5	46	100.00%	$ 917,068	0.3855	$ 353,530	27.65
2005	$ 544,412	21.5	48	100.00%	$ 544,412	0.4006	$ 218,091	26.97
2004	$ 911,322	22.5	50	100.00%	$ 911,322	0.4155	$ 378,654	26.30
2003	$ 1,061,747	23.5	52	100.00%	$ 1,061,747	0.4302	$ 456,764	25.64
2002	$ 649,254	24.5	54	100.00%	$ 649,254	0.4447	$ 288,723	24.99
2001	$ 267,260	25.5	57	100.00%	$ 267,260	0.4662	$ 124,597	24.02
2000	$ 657,238	26.5	59	100.00%	$ 657,238	0.4803	$ 315,671	23.39
1999	$ 958,167	27.5	61	100.00%	$ 958,167	0.4942	$ 473,526	22.76
1998	$ 804,305	28.5	63	100.00%	$ 804,305	0.5080	$ 408,587	22.14
1997	$ 864,489	29.5	66	100.00%	$ 864,489	0.5282	$ 456,623	21.23
1996	$ 944,972	30.5	68	100.00%	$ 944,972	0.5414	$ 511,608	20.64

1995	$ 702,044	31.5	70	100.00%	$ 702,044	0.5544	$ 389,213	20.05
1994	$ 544,738	32.5	72	100.00%	$ 544,738	0.5673	$ 309,030	19.47
1993	$ 355,583	33.5	74	100.00%	$ 355,583	0.5799	$ 206,202	18.90
1992	$ 472,993	34.5	77	100.00%	$ 472,993	0.5984	$ 283,039	18.07
1991	$ 607,700	35.5	79	100.00%	$ 607,700	0.6105	$ 371,001	17.53
1990	$ 481,328	36.5	81	100.00%	$ 481,328	0.6223	$ 299,531	17.00
1989	$ 395,502	37.5	83	100.00%	$ 395,502	0.6339	$ 250,709	16.47
1988	$ 645,720	38.5	86	100.00%	$ 645,720	0.6510	$ 420,363	15.71
1987	$ 354,455	39.5	88	100.00%	$ 354,455	0.6620	$ 234,649	15.21
1986	$ 223,035	40.5	90	100.00%	$ 223,035	0.6728	$ 150,058	14.72
1985	$ 252,134	41.5	92	100.00%	$ 252,134	0.6834	$ 172,308	14.25
1984	$ 202,668	42.5	94	100.00%	$ 202,668	0.6938	$ 140,611	13.78
1983	$ 187,335	43.5	97	100.00%	$ 187,335	0.7088	$ 132,783	13.10
1982	$ 395,075	44.5	99	100.00%	$ 395,075	0.7186	$ 283,901	12.66
1981	$ 618,866	45.5	101	100.00%	$ 618,866	0.7281	$ 450,596	12.24
1980	$ 861,866	46.5	103	100.00%	$ 861,866	0.7374	$ 635,540	11.82
1979	$ 238,879	47.5	106	100.00%	$ 238,879	0.7508	$ 179,350	11.21
1978	$ 59,525	48.5	108	100.00%	$ 59,525	0.7595	$ 45,209	10.82
1977	$ 34,483	49.5	110	100.00%	$ 34,483	0.7680	$ 26,483	10.44
1976	$ 63,307	50.5	112	100.00%	$ 63,307	0.7762	$ 49,139	10.07
1975	$ 63,398	51.5	114	100.00%	$ 63,398	0.7842	$ 49,717	9.71
1974	$ 116,531	52.5	117	100.00%	$ 116,531	0.7958	$ 92,736	9.19
1973	$ 130,330	53.5	119	100.00%	$ 130,330	0.8033	$ 104,694	8.85
1972	$ 349,723	54.5	121	100.00%	$ 349,723	0.8106	$ 283,485	8.52
1971	$ 296,585	55.5	123	100.00%	$ 296,585	0.8177	$ 242,517	8.20
1970	$ 365,653	56.5	126	100.00%	$ 365,653	0.8281	$ 302,798	7.74
1969	$ 320,258	57.5	128	100.00%	$ 320,258	0.8347	$ 267,320	7.44
1968	$ 352,501	58.5	130	100.00%	$ 352,501	0.8413	$ 296,559	7.14
1967	$ 288,208	59.5	132	100.00%	$ 288,208	0.8477	$ 244,314	6.85
1966	$ 186,998	60.5	134	100.00%	$ 186,998	0.8539	$ 159,677	6.57
1965	$ 190,991	61.5	137	100.00%	$ 190,991	0.8632	$ 164,864	6.16
1964	$ 126,480	62.5	139	100.00%	$ 126,480	0.8692	$ 109,937	5.89
1963	$ 112,178	63.5	141	100.00%	$ 112,178	0.8752	$ 98,178	5.62
1962	$ 56,034	64.5	143	100.00%	$ 56,034	0.8811	$ 49,372	5.35
1961	$ 28,547	65.5	146	100.00%	$ 28,547	0.8899	$ 25,404	4.95
1960	$ 71,268	66.5	148	100.00%	$ 71,268	0.8958	$ 63,842	4.69
1959	$ 13,845	67.5	150	100.00%	$ 13,845	0.9016	$ 12,483	4.43
1958	$ 7,673	68.5	152	100.00%	$ 7,673	0.9074	$ 6,962	4.17
1957	$ 18,861	69.5	154	100.00%	$ 18,861	0.9132	$ 17,224	3.91
1956	$ 17,284	70.5	157	100.00%	$ 17,284	0.9219	$ 15,934	3.51
1955	$ 1,459	71.5	159	100.00%	$ 1,459	0.9277	$ 1,354	3.25
1954	$ 2,156	72.5	161	100.00%	$ 2,156	0.9334	$ 2,012	3.00
1953	$ 692	73.5	163	100.00%	$ 692	0.9391	$ 649	2.74
1952	$ 1,264	74.5	166	100.00%	$ 1,264	0.9476	$ 1,198	2.36
1951	$ -	75.5	168	100.00%	$ -	0.9532	$ -	2.11
1950	$ 87	76.5	170	100.00%	$ 87	0.9587	$ 84	1.86
1949	$ 87	77.5	172	100.00%	$ 87	0.9641	$ 84	1.62
1948	$ 87	78.5	174	100.00%	$ 87	0.9695	$ 85	1.37
1947	$ 190	79.5	177	100.00%	$ 190	0.9774	$ 185	1.02

1946	$	211	80.5	179	100.00%	$	211	0.9825	$	207	0.79
1945	$	198	81.5	181	100.00%	$	198	0.9876	$	195	0.56
1944	$	66	82.5	183	100.00%	$	66	0.9923	$	66	0.35
1943	$	520	83.5	186	100.00%	$	520	1.0000	$	520	0.00
1942	$	133	84.5	188	100.00%	$	133	1.0000	$	133	0.00
1941	$	90	85.5	190	100.00%	$	90	1.0000	$	90	0.00
1940	$	-	86.5	192	100.00%	$	-	1.0000	$	-	0.00
1939	$	90	87.5	194	100.00%	$	90	1.0000	$	90	0.00
1938	$	-	88.5	197	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	199	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	201	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	203	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	206	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	208	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	210	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	212	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	214	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	217	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	219	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	221	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	223	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	226	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	228	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	230	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	232	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	234	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	237	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	239	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	241	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	243	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	246	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	248	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	250	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	252	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	254	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	257	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	259	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	261	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	263	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	266	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	268	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	270	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	272	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	274	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	277	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	279	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	281	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	283	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	286	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	288	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	290	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	292	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	294	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	297	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	299	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	301	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	303	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	306	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	308	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	310	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	312	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	314	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	317	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	319	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	321	100.00%	$ -	1.0000	$ -	0.00
Total	$ 41,443,487				$ 41,443,487		$ 15,942,983	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 15,942,983	
Average Remaining Life		27.69
Theoretical Reserve %	38.47%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38600**
Plant Account **OTHER PROPERTY ON CUSTOMERS PREMISES**

Survivor Curve R2
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0091	$ -	44.59
2025	$ -	1.5	3	100.00%	$ -	0.0271	$ -	43.78
2024	$ -	2.5	6	100.00%	$ -	0.0540	$ -	42.57
2023	$ -	3.5	8	100.00%	$ -	0.0717	$ -	41.77
2022	$ -	4.5	10	100.00%	$ -	0.0894	$ -	40.98
2021	$ -	5.5	12	100.00%	$ -	0.1070	$ -	40.19
2020	$ -	6.5	14	100.00%	$ -	0.1244	$ -	39.40
2019	$ -	7.5	17	100.00%	$ -	0.1503	$ -	38.24
2018	$ -	8.5	19	100.00%	$ -	0.1675	$ -	37.46
2017	$ -	9.5	21	100.00%	$ -	0.1845	$ -	36.70
2016	$ -	10.5	23	100.00%	$ -	0.2014	$ -	35.94
2015	$ -	11.5	26	100.00%	$ -	0.2265	$ -	34.81
2014	$ -	12.5	28	100.00%	$ -	0.2430	$ -	34.07
2013	$ -	13.5	30	100.00%	$ -	0.2595	$ -	33.32
2012	$ -	14.5	32	100.00%	$ -	0.2757	$ -	32.59
2011	$ -	15.5	34	100.00%	$ -	0.2919	$ -	31.86
2010	$ -	16.5	37	100.00%	$ -	0.3158	$ -	30.79
2009	$ -	17.5	39	100.00%	$ -	0.3316	$ -	30.08
2008	$ -	18.5	41	100.00%	$ -	0.3472	$ -	29.38
2007	$ -	19.5	43	100.00%	$ -	0.3627	$ -	28.68
2006	$ -	20.5	46	100.00%	$ -	0.3855	$ -	27.65
2005	$ 22,926	21.5	48	100.00%	$ 22,926	0.4006	$ 9,184	26.97
2004	$ 19,261	22.5	50	100.00%	$ 19,261	0.4155	$ 8,003	26.30
2003	$ -	23.5	52	100.00%	$ -	0.4302	$ -	25.64
2002	$ -	24.5	54	100.00%	$ -	0.4447	$ -	24.99
2001	$ -	25.5	57	100.00%	$ -	0.4662	$ -	24.02
2000	$ -	26.5	59	100.00%	$ -	0.4803	$ -	23.39
1999	$ -	27.5	61	100.00%	$ -	0.4942	$ -	22.76
1998	$ -	28.5	63	100.00%	$ -	0.5080	$ -	22.14
1997	$ -	29.5	66	100.00%	$ -	0.5282	$ -	21.23
1996	$ -	30.5	68	100.00%	$ -	0.5414	$ -	20.64

1995	$ -	31.5	70	100.00%	$ -	0.5544	$ -	20.05
1994	$ -	32.5	72	100.00%	$ -	0.5673	$ -	19.47
1993	$ -	33.5	74	100.00%	$ -	0.5799	$ -	18.90
1992	$ -	34.5	77	100.00%	$ -	0.5984	$ -	18.07
1991	$ -	35.5	79	100.00%	$ -	0.6105	$ -	17.53
1990	$ -	36.5	81	100.00%	$ -	0.6223	$ -	17.00
1989	$ -	37.5	83	100.00%	$ -	0.6339	$ -	16.47
1988	$ -	38.5	86	100.00%	$ -	0.6510	$ -	15.71
1987	$ -	39.5	88	100.00%	$ -	0.6620	$ -	15.21
1986	$ -	40.5	90	100.00%	$ -	0.6728	$ -	14.72
1985	$ -	41.5	92	100.00%	$ -	0.6834	$ -	14.25
1984	$ -	42.5	94	100.00%	$ -	0.6938	$ -	13.78
1983	$ -	43.5	97	100.00%	$ -	0.7088	$ -	13.10
1982	$ -	44.5	99	100.00%	$ -	0.7186	$ -	12.66
1981	$ -	45.5	101	100.00%	$ -	0.7281	$ -	12.24
1980	$ -	46.5	103	100.00%	$ -	0.7374	$ -	11.82
1979	$ -	47.5	106	100.00%	$ -	0.7508	$ -	11.21
1978	$ -	48.5	108	100.00%	$ -	0.7595	$ -	10.82
1977	$ -	49.5	110	100.00%	$ -	0.7680	$ -	10.44
1976	$ -	50.5	112	100.00%	$ -	0.7762	$ -	10.07
1975	$ -	51.5	114	100.00%	$ -	0.7842	$ -	9.71
1974	$ -	52.5	117	100.00%	$ -	0.7958	$ -	9.19
1973	$ -	53.5	119	100.00%	$ -	0.8033	$ -	8.85
1972	$ 16,781	54.5	121	100.00%	$ 16,781	0.8106	$ 13,602	8.52
1971	$ 1,925	55.5	123	100.00%	$ 1,925	0.8177	$ 1,574	8.20
1970	$ 585	56.5	126	100.00%	$ 585	0.8281	$ 485	7.74
1969	$ 4,349	57.5	128	100.00%	$ 4,349	0.8347	$ 3,630	7.44
1968	$ 821	58.5	130	100.00%	$ 821	0.8413	$ 691	7.14
1967	$ 207	59.5	132	100.00%	$ 207	0.8477	$ 176	6.85
1966	$ 1,969	60.5	134	100.00%	$ 1,969	0.8539	$ 1,681	6.57
1965	$ -	61.5	137	100.00%	$ -	0.8632	$ -	6.16
1964	$ -	62.5	139	100.00%	$ -	0.8692	$ -	5.89
1963	$ -	63.5	141	100.00%	$ -	0.8752	$ -	5.62
1962	$ -	64.5	143	100.00%	$ -	0.8811	$ -	5.35
1961	$ -	65.5	146	100.00%	$ -	0.8899	$ -	4.95
1960	$ -	66.5	148	100.00%	$ -	0.8958	$ -	4.69
1959	$ -	67.5	150	100.00%	$ -	0.9016	$ -	4.43
1958	$ -	68.5	152	100.00%	$ -	0.9074	$ -	4.17
1957	$ -	69.5	154	100.00%	$ -	0.9132	$ -	3.91
1956	$ -	70.5	157	100.00%	$ -	0.9219	$ -	3.51
1955	$ -	71.5	159	100.00%	$ -	0.9277	$ -	3.25
1954	$ -	72.5	161	100.00%	$ -	0.9334	$ -	3.00
1953	$ -	73.5	163	100.00%	$ -	0.9391	$ -	2.74
1952	$ -	74.5	166	100.00%	$ -	0.9476	$ -	2.36
1951	$ -	75.5	168	100.00%	$ -	0.9532	$ -	2.11
1950	$ -	76.5	170	100.00%	$ -	0.9587	$ -	1.86
1949	$ -	77.5	172	100.00%	$ -	0.9641	$ -	1.62
1948	$ -	78.5	174	100.00%	$ -	0.9695	$ -	1.37
1947	$ -	79.5	177	100.00%	$ -	0.9774	$ -	1.02

1946	$	-	80.5	179	100.00%	$	-	0.9825	$	-	0.79
1945	$	-	81.5	181	100.00%	$	-	0.9876	$	-	0.56
1944	$	-	82.5	183	100.00%	$	-	0.9923	$	-	0.35
1943	$	-	83.5	186	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	188	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	190	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	192	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	194	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	197	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	199	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	201	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	203	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	206	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	208	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	210	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	212	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	214	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	217	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	219	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	221	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	223	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	226	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	228	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	230	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	232	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	234	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	237	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	239	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	241	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	243	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	246	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	248	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	250	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	252	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	254	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	257	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	259	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	261	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	263	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	266	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	268	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	270	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	272	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	274	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	277	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	279	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	281	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	283	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	286	100.00%	$	-	1.0000	$	-	0.00

1897	$ -	129.5	288	100.00%	$ -	1.0000	$ -	0.00
1896	$ -	130.5	290	100.00%	$ -	1.0000	$ -	0.00
1895	$ -	131.5	292	100.00%	$ -	1.0000	$ -	0.00
1894	$ -	132.5	294	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	297	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	299	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	301	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	303	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	306	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	308	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	310	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	312	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	314	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	317	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	319	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	321	100.00%	$ -	1.0000	$ -	0.00
Total	$ 68,824				$ 68,824		$ 39,026	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage		$ 39,026
Average Remaining Life		19.48
Theoretical Reserve %		56.70%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38610**
Plant Account **OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS**

Survivor Curve R1.5
Average Service Life 45
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0083	$ -	44.63
2025	$ 103,839	1.5	3	100.00%	$ 103,839	0.0247	$ 2,565	43.89
2024	$ 123,718	2.5	6	100.00%	$ 123,718	0.0492	$ 6,087	42.79
2023	$ -	3.5	8	100.00%	$ -	0.0653	$ -	42.06
2022	$ -	4.5	10	100.00%	$ -	0.0814	$ -	41.34
2021	$ -	5.5	12	100.00%	$ -	0.0974	$ -	40.62
2020	$ -	6.5	14	100.00%	$ -	0.1133	$ -	39.90
2019	$ 1,261	7.5	17	100.00%	$ 1,261	0.1370	$ 173	38.84
2018	$ 4,741	8.5	19	100.00%	$ 4,741	0.1527	$ 724	38.13
2017	$ 320	9.5	21	100.00%	$ 320	0.1683	$ 54	37.43
2016	$ -	10.5	23	100.00%	$ -	0.1837	$ -	36.73
2015	$ 1,658	11.5	26	100.00%	$ 1,658	0.2068	$ 343	35.69
2014	$ 10,178	12.5	28	100.00%	$ 10,178	0.2220	$ 2,260	35.01
2013	$ 22,348	13.5	30	100.00%	$ 22,348	0.2372	$ 5,301	34.33
2012	$ 115,202	14.5	32	100.00%	$ 115,202	0.2522	$ 29,054	33.65
2011	$ -	15.5	34	100.00%	$ -	0.2672	$ -	32.98
2010	$ 55	16.5	37	100.00%	$ 55	0.2894	$ 16	31.98
2009	$ -	17.5	39	100.00%	$ -	0.3041	$ -	31.32
2008	$ -	18.5	41	100.00%	$ -	0.3187	$ -	30.66
2007	$ -	19.5	43	100.00%	$ -	0.3331	$ -	30.01
2006	$ 3,670	20.5	46	100.00%	$ 3,670	0.3546	$ 1,302	29.04
2005	$ 3,317	21.5	48	100.00%	$ 3,317	0.3687	$ 1,223	28.41
2004	$ 347	22.5	50	100.00%	$ 347	0.3827	$ 133	27.78
2003	$ -	23.5	52	100.00%	$ -	0.3966	$ -	27.15
2002	$ -	24.5	54	100.00%	$ -	0.4104	$ -	26.53
2001	$ -	25.5	57	100.00%	$ -	0.4307	$ -	25.62
2000	$ 2,552	26.5	59	100.00%	$ 2,552	0.4441	$ 1,133	25.02
1999	$ 13,041	27.5	61	100.00%	$ 13,041	0.4573	$ 5,964	24.42
1998	$ 8,784	28.5	63	100.00%	$ 8,784	0.4703	$ 4,131	23.84
1997	$ 8,544	29.5	66	100.00%	$ 8,544	0.4896	$ 4,183	22.97
1996	$ 22,335	30.5	68	100.00%	$ 22,335	0.5023	$ 11,219	22.40
1995	$ 22,679	31.5	70	100.00%	$ 22,679	0.5147	$ 11,673	21.84
1994	$ 30,338	32.5	72	100.00%	$ 30,338	0.5270	$ 15,988	21.29
1993	$ 45,456	33.5	74	100.00%	$ 45,456	0.5391	$ 24,505	20.74

1992	$	56,753	34.5	77	100.00%	$	56,753	0.5569	$	31,606	19.94
1991	$	30,826	35.5	79	100.00%	$	30,826	0.5686	$	17,528	19.41
1990	$	55,497	36.5	81	100.00%	$	55,497	0.5800	$	32,188	18.90
1989	$	52,802	37.5	83	100.00%	$	52,802	0.5913	$	31,222	18.39
1988	$	26,270	38.5	86	100.00%	$	26,270	0.6078	$	15,967	17.65
1987	$	25,831	39.5	88	100.00%	$	25,831	0.6185	$	15,976	17.17
1986	$	23,744	40.5	90	100.00%	$	23,744	0.6290	$	14,935	16.70
1985	$	25,258	41.5	92	100.00%	$	25,258	0.6394	$	16,150	16.23
1984	$	6,649	42.5	94	100.00%	$	6,649	0.6495	$	4,319	15.77
1983	$	6,768	43.5	97	100.00%	$	6,768	0.6643	$	4,496	15.11
1982	$	95,201	44.5	99	100.00%	$	95,201	0.6739	$	64,156	14.67
1981	$	121,509	45.5	101	100.00%	$	121,509	0.6833	$	83,027	14.25
1980	$	17,091	46.5	103	100.00%	$	17,091	0.6925	$	11,836	13.84
1979	$	5,236	47.5	106	100.00%	$	5,236	0.7059	$	3,696	13.23
1978	$	183	48.5	108	100.00%	$	183	0.7145	$	131	12.85
1977	$	1,422	49.5	110	100.00%	$	1,422	0.7230	$	1,028	12.47
1976	$	3,733	50.5	112	100.00%	$	3,733	0.7313	$	2,730	12.09
1975	$	502	51.5	114	100.00%	$	502	0.7393	$	371	11.73
1974	$	678	52.5	117	100.00%	$	678	0.7511	$	509	11.20
1973	$	5,741	53.5	119	100.00%	$	5,741	0.7587	$	4,356	10.86
1972	$	2,029	54.5	121	100.00%	$	2,029	0.7661	$	1,554	10.53
1971	$	31,925	55.5	123	100.00%	$	31,925	0.7733	$	24,688	10.20
1970	$	1,105	56.5	126	100.00%	$	1,105	0.7798	$	862	9.91
1969	$	2,743	57.5	128	100.00%	$	2,743	0.7905	$	2,169	9.43
1968	$	5,157	58.5	130	100.00%	$	5,157	0.7972	$	4,111	9.13
1967	$	7,811	59.5	132	100.00%	$	7,811	0.8038	$	6,278	8.83
1966	$	1,500	60.5	134	100.00%	$	1,500	0.8102	$	1,215	8.54
1965	$	611	61.5	137	100.00%	$	611	0.8197	$	501	8.11
1964	$	1,895	62.5	139	100.00%	$	1,895	0.8258	$	1,565	7.84
1963	$	1,519	63.5	141	100.00%	$	1,519	0.8319	$	1,264	7.56
1962	$	1,777	64.5	143	100.00%	$	1,777	0.8379	$	1,489	7.29
1961	$	5,466	65.5	146	100.00%	$	5,466	0.8466	$	4,627	6.90
1960	$	6,232	66.5	148	100.00%	$	6,232	0.8524	$	5,312	6.64
1959	$	739	67.5	150	100.00%	$	739	0.8581	$	634	6.39
1958	$	237	68.5	152	100.00%	$	237	0.8637	$	204	6.13
1957	$	546	69.5	154	100.00%	$	546	0.8692	$	474	5.89
1956	$	989	70.5	157	100.00%	$	989	0.8772	$	868	5.53
1955	$	2,275	71.5	159	100.00%	$	2,275	0.8825	$	2,008	5.29
1954	$	-	72.5	161	100.00%	$	-	0.8876	$	-	5.06
1953	$	-	73.5	163	100.00%	$	-	0.8926	$	-	4.83
1952	$	-	74.5	166	100.00%	$	-	0.8999	$	-	4.50
1951	$	-	75.5	168	100.00%	$	-	0.9046	$	-	4.29
1950	$	-	76.5	170	100.00%	$	-	0.9091	$	-	4.09
1949	$	-	77.5	172	100.00%	$	-	0.9136	$	-	3.89
1948	$	-	78.5	174	100.00%	$	-	0.9181	$	-	3.69
1947	$	-	79.5	177	100.00%	$	-	0.9250	$	-	3.38
1946	$	-	80.5	179	100.00%	$	-	0.9298	$	-	3.16
1945	$	-	81.5	181	100.00%	$	-	0.9349	$	-	2.93
1944	$	-	82.5	183	100.00%	$	-	0.9405	$	-	2.68
1943	$	-	83.5	186	100.00%	$	-	0.9500	$	-	2.25
1942	$	-	84.5	188	100.00%	$	-	0.9567	$	-	1.95
1941	$	-	85.5	190	100.00%	$	-	0.9635	$	-	1.64

1940	$	-	86.5	192	100.00%	$	-	0.9703	$	-	1.34
1939	$	-	87.5	194	100.00%	$	-	0.9769	$	-	1.04
1938	$	-	88.5	197	100.00%	$	-	0.9868	$	-	0.59
1937	$	-	89.5	199	100.00%	$	-	0.9928	$	-	0.32
1936	$	-	90.5	201	100.00%	$	-	0.0000	$	-	45.00
1935	$	-	91.5	203	100.00%	$	-	0.0000	$	-	45.00
1934	$	-	92.5	206	100.00%	$	-	0.0000	$	-	45.00
1933	$	-	93.5	208	100.00%	$	-	0.0000	$	-	45.00
1932	$	-	94.5	210	100.00%	$	-	0.0000	$	-	45.00
1931	$	-	95.5	212	100.00%	$	-	0.0000	$	-	45.00
1930	$	-	96.5	214	100.00%	$	-	0.0000	$	-	45.00
1929	$	141	97.5	217	100.00%	$	141	0.0000	$	-	45.00
1928	$	-	98.5	219	100.00%	$	-	0.0000	$	-	45.00
1927	$	-	99.5	221	100.00%	$	-	0.0000	$	-	45.00
1926	$	-	100.5	223	100.00%	$	-	0.0000	$	-	45.00
1925	$	-	101.5	226	100.00%	$	-	0.0000	$	-	45.00
1924	$	-	102.5	228	100.00%	$	-	0.0000	$	-	45.00
1923	$	-	103.5	230	100.00%	$	-	0.0000	$	-	45.00
1922	$	-	104.5	232	100.00%	$	-	0.0000	$	-	45.00
1921	$	-	105.5	234	100.00%	$	-	0.0000	$	-	45.00
1920	$	-	106.5	237	100.00%	$	-	0.0000	$	-	45.00
1919	$	-	107.5	239	100.00%	$	-	0.0000	$	-	45.00
1918	$	-	108.5	241	100.00%	$	-	0.0000	$	-	45.00
1917	$	-	109.5	243	100.00%	$	-	0.0000	$	-	45.00
1916	$	-	110.5	246	100.00%	$	-	0.0000	$	-	45.00
1915	$	-	111.5	248	100.00%	$	-	0.0000	$	-	45.00
1914	$	-	112.5	250	100.00%	$	-	0.0000	$	-	45.00
1913	$	-	113.5	252	100.00%	$	-	0.0000	$	-	45.00
1912	$	-	114.5	254	100.00%	$	-	0.0000	$	-	45.00
1911	$	-	115.5	257	100.00%	$	-	0.0000	$	-	45.00
1910	$	-	116.5	259	100.00%	$	-	0.0000	$	-	45.00
1909	$	-	117.5	261	100.00%	$	-	0.0000	$	-	45.00
1908	$	-	118.5	263	100.00%	$	-	0.0000	$	-	45.00
1907	$	-	119.5	266	100.00%	$	-	0.0000	$	-	45.00
1906	$	-	120.5	268	100.00%	$	-	0.0000	$	-	45.00
1905	$	-	121.5	270	100.00%	$	-	0.0000	$	-	45.00
1904	$	-	122.5	272	100.00%	$	-	0.0000	$	-	45.00
1903	$	-	123.5	274	100.00%	$	-	0.0000	$	-	45.00
1902	$	-	124.5	277	100.00%	$	-	0.0000	$	-	45.00
1901	$	-	125.5	279	100.00%	$	-	0.0000	$	-	45.00
1900	$	-	126.5	281	100.00%	$	-	0.0000	$	-	45.00
1899	$	-	127.5	283	100.00%	$	-	0.0000	$	-	45.00
1898	$	-	128.5	286	100.00%	$	-	0.0000	$	-	45.00
1897	$	-	129.5	288	100.00%	$	-	0.0000	$	-	45.00
1896	$	-	130.5	290	100.00%	$	-	0.0000	$	-	45.00
1895	$	-	131.5	292	100.00%	$	-	0.0000	$	-	45.00
1894	$	-	132.5	294	100.00%	$	-	0.0000	$	-	45.00
1893	$	-	133.5	297	100.00%	$	-	0.0000	$	-	45.00
1892	$	-	134.5	299	100.00%	$	-	0.0000	$	-	45.00
1891	$	-	135.5	301	100.00%	$	-	0.0000	$	-	45.00
1890	$	-	136.5	303	100.00%	$	-	0.0000	$	-	45.00
1889	$	-	137.5	306	100.00%	$	-	0.0000	$	-	45.00

1888	$	-	138.5	308	100.00%	$	-	0.0000	$	-	45.00
1887	$	-	139.5	310	100.00%	$	-	0.0000	$	-	45.00
1886	$	-	140.5	312	100.00%	$	-	0.0000	$	-	45.00
1885	$	-	141.5	314	100.00%	$	-	0.0000	$	-	45.00
1884	$	-	142.5	317	100.00%	$	-	0.0000	$	-	45.00
1883	$	-	143.5	319	100.00%	$	-	0.0000	$	-	45.00
1882	$	-	144.5	321	100.00%	$	-	0.0000	$	-	45.00
Total	$	1,180,774				$	1,180,774		$	544,081	

Net Salvage Value		0%
Theoretical Reserve Including Net Salvage	$	544,081
Average Remaining Life		24.26
Theoretical Reserve %		46.08%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38620**
Plant Account **OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS**

Survivor Curve R3
Average Service Life 25
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	2	100.00%	$ -	0.0197	$ -	24.51
2025	$ -	1.5	6	100.00%	$ -	0.0589	$ -	23.53
2024	$ -	2.5	10	100.00%	$ -	0.0978	$ -	22.56
2023	$ -	3.5	14	100.00%	$ -	0.1365	$ -	21.59
2022	$ -	4.5	18	100.00%	$ -	0.1748	$ -	20.63
2021	$ -	5.5	22	100.00%	$ -	0.2127	$ -	19.68
2020	$ -	6.5	26	100.00%	$ -	0.2501	$ -	18.75
2019	$ -	7.5	30	100.00%	$ -	0.2871	$ -	17.82
2018	$ -	8.5	34	100.00%	$ -	0.3234	$ -	16.92
2017	$ -	9.5	38	100.00%	$ -	0.3591	$ -	16.02
2016	$ -	10.5	42	100.00%	$ -	0.3942	$ -	15.15
2015	$ -	11.5	46	100.00%	$ -	0.4285	$ -	14.29
2014	$ -	12.5	50	100.00%	$ -	0.4621	$ -	13.45
2013	$ -	13.5	54	100.00%	$ -	0.4949	$ -	12.63
2012	$ -	14.5	58	100.00%	$ -	0.5268	$ -	11.83
2011	$ -	15.5	62	100.00%	$ -	0.5580	$ -	11.05
2010	$ -	16.5	66	100.00%	$ -	0.5882	$ -	10.30
2009	$ -	17.5	70	100.00%	$ -	0.6174	$ -	9.57
2008	$ -	18.5	74	100.00%	$ -	0.6456	$ -	8.86
2007	$ -	19.5	78	100.00%	$ -	0.6727	$ -	8.18
2006	$ -	20.5	82	100.00%	$ -	0.6986	$ -	7.54
2005	$ -	21.5	86	100.00%	$ -	0.7233	$ -	6.92
2004	$ -	22.5	90	100.00%	$ -	0.7465	$ -	6.34
2003	$ -	23.5	94	100.00%	$ -	0.7684	$ -	5.79
2002	$ -	24.5	98	100.00%	$ -	0.7887	$ -	5.28
2001	$ -	25.5	102	100.00%	$ -	0.8075	$ -	4.81
2000	$ -	26.5	106	100.00%	$ -	0.8247	$ -	4.38
1999	$ -	27.5	110	100.00%	$ -	0.8406	$ -	3.99
1998	$ -	28.5	114	100.00%	$ -	0.8550	$ -	3.63
1997	$ 104	29.5	118	100.00%	$ 104	0.8682	$ 90	3.30
1996	$ -	30.5	122	100.00%	$ -	0.8804	$ -	2.99

1995	$ -	31.5	126	100.00%	$ -	0.8918	$ -	2.71
1994	$ 335	32.5	130	100.00%	$ 335	0.9026	$ 303	2.44
1993	$ 5,858	33.5	134	100.00%	$ 5,858	0.9130	$ 5,349	2.18
1992	$ 3,051	34.5	138	100.00%	$ 3,051	0.9233	$ 2,817	1.92
1991	$ 4,510	35.5	142	100.00%	$ 4,510	0.9336	$ 4,211	1.66
1990	$ 10,556	36.5	146	100.00%	$ 10,556	0.9439	$ 9,964	1.40
1989	$ 291	37.5	150	100.00%	$ 291	0.9541	$ 277	1.15
1988	$ -	38.5	154	100.00%	$ -	0.9641	$ -	0.90
1987	$ -	39.5	158	100.00%	$ -	0.9737	$ -	0.66
1986	$ -	40.5	162	100.00%	$ -	0.9830	$ -	0.43
1985	$ -	41.5	166	100.00%	$ -	0.9917	$ -	0.21
1984	$ -	42.5	170	100.00%	$ -	1.0000	$ -	0.00
1983	$ -	43.5	174	100.00%	$ -	1.0000	$ -	0.00
1982	$ -	44.5	178	100.00%	$ -	1.0000	$ -	0.00
1981	$ -	45.5	182	100.00%	$ -	1.0000	$ -	0.00
1980	$ -	46.5	186	100.00%	$ -	1.0000	$ -	0.00
1979	$ -	47.5	190	100.00%	$ -	1.0000	$ -	0.00
1978	$ -	48.5	194	100.00%	$ -	1.0000	$ -	0.00
1977	$ -	49.5	198	100.00%	$ -	1.0000	$ -	0.00
1976	$ -	50.5	202	100.00%	$ -	1.0000	$ -	0.00
1975	$ -	51.5	206	100.00%	$ -	1.0000	$ -	0.00
1974	$ -	52.5	210	100.00%	$ -	1.0000	$ -	0.00
1973	$ -	53.5	214	100.00%	$ -	1.0000	$ -	0.00
1972	$ -	54.5	218	100.00%	$ -	1.0000	$ -	0.00
1971	$ -	55.5	222	100.00%	$ -	1.0000	$ -	0.00
1970	$ -	56.5	226	100.00%	$ -	1.0000	$ -	0.00
1969	$ -	57.5	230	100.00%	$ -	1.0000	$ -	0.00
1968	$ -	58.5	234	100.00%	$ -	1.0000	$ -	0.00
1967	$ -	59.5	238	100.00%	$ -	1.0000	$ -	0.00
1966	$ -	60.5	242	100.00%	$ -	1.0000	$ -	0.00
1965	$ -	61.5	246	100.00%	$ -	1.0000	$ -	0.00
1964	$ -	62.5	250	100.00%	$ -	1.0000	$ -	0.00
1963	$ -	63.5	254	100.00%	$ -	1.0000	$ -	0.00
1962	$ -	64.5	258	100.00%	$ -	1.0000	$ -	0.00
1961	$ -	65.5	262	100.00%	$ -	1.0000	$ -	0.00
1960	$ -	66.5	266	100.00%	$ -	1.0000	$ -	0.00
1959	$ -	67.5	270	100.00%	$ -	1.0000	$ -	0.00
1958	$ -	68.5	274	100.00%	$ -	1.0000	$ -	0.00
1957	$ -	69.5	278	100.00%	$ -	1.0000	$ -	0.00
1956	$ -	70.5	282	100.00%	$ -	1.0000	$ -	0.00
1955	$ -	71.5	286	100.00%	$ -	1.0000	$ -	0.00
1954	$ -	72.5	290	100.00%	$ -	1.0000	$ -	0.00
1953	$ -	73.5	294	100.00%	$ -	1.0000	$ -	0.00
1952	$ -	74.5	298	100.00%	$ -	1.0000	$ -	0.00
1951	$ -	75.5	302	100.00%	$ -	1.0000	$ -	0.00
1950	$ -	76.5	306	100.00%	$ -	1.0000	$ -	0.00
1949	$ -	77.5	310	100.00%	$ -	1.0000	$ -	0.00
1948	$ -	78.5	314	100.00%	$ -	1.0000	$ -	0.00
1947	$ -	79.5	318	100.00%	$ -	1.0000	$ -	0.00

1946	$	-	80.5	322	100.00%	$	-	1.0000	$	-	0.00
1945	$	-	81.5	326	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	330	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	334	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	338	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	342	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	346	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	350	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	354	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	358	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	362	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	366	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	370	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	374	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	378	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	382	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	386	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	390	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	394	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	398	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	402	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	406	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	410	100.00%	$	-	0.0000	$	-	25.00
1923	$	-	103.5	414	100.00%	$	-	0.0000	$	-	25.00
1922	$	-	104.5	418	100.00%	$	-	0.0000	$	-	25.00
1921	$	-	105.5	422	100.00%	$	-	0.0000	$	-	25.00
1920	$	-	106.5	426	100.00%	$	-	0.0000	$	-	25.00
1919	$	-	107.5	430	100.00%	$	-	0.0000	$	-	25.00
1918	$	-	108.5	434	100.00%	$	-	0.0000	$	-	25.00
1917	$	-	109.5	438	100.00%	$	-	0.0000	$	-	25.00
1916	$	-	110.5	442	100.00%	$	-	0.0000	$	-	25.00
1915	$	-	111.5	446	100.00%	$	-	0.0000	$	-	25.00
1914	$	-	112.5	450	100.00%	$	-	0.0000	$	-	25.00
1913	$	-	113.5	454	100.00%	$	-	0.0000	$	-	25.00
1912	$	-	114.5	458	100.00%	$	-	0.0000	$	-	25.00
1911	$	-	115.5	462	100.00%	$	-	0.0000	$	-	25.00
1910	$	-	116.5	466	100.00%	$	-	0.0000	$	-	25.00
1909	$	-	117.5	470	100.00%	$	-	0.0000	$	-	25.00
1908	$	-	118.5	474	100.00%	$	-	0.0000	$	-	25.00
1907	$	-	119.5	478	100.00%	$	-	0.0000	$	-	25.00
1906	$	-	120.5	482	100.00%	$	-	0.0000	$	-	25.00
1905	$	-	121.5	486	100.00%	$	-	0.0000	$	-	25.00
1904	$	-	122.5	490	100.00%	$	-	0.0000	$	-	25.00
1903	$	-	123.5	494	100.00%	$	-	0.0000	$	-	25.00
1902	$	-	124.5	498	100.00%	$	-	0.0000	$	-	25.00
1901	$	-	125.5	502	100.00%	$	-	0.0000	$	-	25.00
1900	$	-	126.5	506	100.00%	$	-	0.0000	$	-	25.00
1899	$	-	127.5	510	100.00%	$	-	0.0000	$	-	25.00
1898	$	-	128.5	514	100.00%	$	-	0.0000	$	-	25.00

1897	$ -	129.5	518	100.00%	$ -	0.0000	$ -	25.00
1896	$ -	130.5	522	100.00%	$ -	0.0000	$ -	25.00
1895	$ -	131.5	526	100.00%	$ -	0.0000	$ -	25.00
1894	$ -	132.5	530	100.00%	$ -	0.0000	$ -	25.00
1893	$ -	133.5	534	100.00%	$ -	0.0000	$ -	25.00
1892	$ -	134.5	538	100.00%	$ -	0.0000	$ -	25.00
1891	$ -	135.5	542	100.00%	$ -	0.0000	$ -	25.00
1890	$ -	136.5	546	100.00%	$ -	0.0000	$ -	25.00
1889	$ -	137.5	550	100.00%	$ -	0.0000	$ -	25.00
1888	$ -	138.5	554	100.00%	$ -	0.0000	$ -	25.00
1887	$ -	139.5	558	100.00%	$ -	0.0000	$ -	25.00
1886	$ -	140.5	562	100.00%	$ -	0.0000	$ -	25.00
1885	$ -	141.5	566	100.00%	$ -	0.0000	$ -	25.00
1884	$ -	142.5	570	100.00%	$ -	0.0000	$ -	25.00
1883	$ -	143.5	574	100.00%	$ -	0.0000	$ -	25.00
1882	$ -	144.5	578	100.00%	$ -	0.0000	$ -	25.00
Total	$ 24,705				$ 24,705		$ 23,011	

Net Salvage Value	0%
Theoretical Reserve Including Net Salvage	$ 23,011
Average Remaining Life	1.71
Theoretical Reserve %	93.14%

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38700**
Plant Account **OTHER EQUIPMENT**

Survivor Curve R2.5
Average Service Life 40
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	1	100.00%	$ -	0.0095	$ -	39.62
2025	$ 66,451	1.5	4	100.00%	$ 66,451	0.0377	$ 2,505	38.49
2024	$ 76,549	2.5	6	100.00%	$ 76,549	0.0564	$ 4,317	37.74
2023	$ 200,051	3.5	9	100.00%	$ 200,051	0.0844	$ 16,884	36.62
2022	$ 93,913	4.5	11	100.00%	$ 93,913	0.1029	$ 9,664	35.88
2021	$ -	5.5	14	100.00%	$ -	0.1305	$ -	34.78
2020	$ 578,465	6.5	16	100.00%	$ 578,465	0.1488	$ 86,076	34.05
2019	$ 217,554	7.5	19	100.00%	$ 217,554	0.1760	$ 38,290	32.96
2018	$ 172,022	8.5	21	100.00%	$ 172,022	0.1940	$ 33,372	32.24
2017	$ 219,792	9.5	24	100.00%	$ 219,792	0.2208	$ 48,530	31.17
2016	$ 116,606	10.5	26	100.00%	$ 116,606	0.2385	$ 27,810	30.46
2015	$ -	11.5	29	100.00%	$ -	0.2648	$ -	29.41
2014	$ 897	12.5	31	100.00%	$ 897	0.2821	$ 253	28.72
2013	$ 30,447	13.5	34	100.00%	$ 30,447	0.3079	$ 9,375	27.68
2012	$ -	14.5	36	100.00%	$ -	0.3249	$ -	27.00
2011	$ 14,981	15.5	39	100.00%	$ 14,981	0.3502	$ 5,246	25.99
2010	$ 4,784	16.5	41	100.00%	$ 4,784	0.3668	$ 1,755	25.33
2009	$ 42,500	17.5	44	100.00%	$ 42,500	0.3914	$ 16,634	24.34
2008	$ 182,975	18.5	46	100.00%	$ 182,975	0.4076	$ 74,581	23.70
2007	$ 37,305	19.5	49	100.00%	$ 37,305	0.4316	$ 16,101	22.74
2006	$ 105,562	20.5	51	100.00%	$ 105,562	0.4473	$ 47,218	22.11
2005	$ 70,406	21.5	54	100.00%	$ 70,406	0.4706	$ 33,133	21.18
2004	$ 109,705	22.5	56	100.00%	$ 109,705	0.4859	$ 53,306	20.56
2003	$ 222,013	23.5	59	100.00%	$ 222,013	0.5084	$ 112,872	19.66
2002	$ 42,457	24.5	61	100.00%	$ 42,457	0.5232	$ 22,214	19.07
2001	$ 116,039	25.5	64	100.00%	$ 116,039	0.5450	$ 63,241	18.20
2000	$ 224,218	26.5	66	100.00%	$ 224,218	0.5593	$ 125,405	17.63
1999	$ 181,978	27.5	69	100.00%	$ 181,978	0.5803	$ 105,602	16.79
1998	$ 359,237	28.5	71	100.00%	$ 359,237	0.5940	$ 213,387	16.24
1997	$ 106,162	29.5	74	100.00%	$ 106,162	0.6140	$ 65,183	15.44
1996	$ 128,973	30.5	76	100.00%	$ 128,973	0.6271	$ 80,879	14.92
1995	$ 277,248	31.5	79	100.00%	$ 277,248	0.6463	$ 179,185	14.15

1994	$	130,403	32.5	81	100.00%	$	130,403	0.6587	$ 85,896	13.65
1993	$	74,597	33.5	84	100.00%	$	74,597	0.6767	$ 50,480	12.93
1992	$	87,675	34.5	86	100.00%	$	87,675	0.6884	$ 60,356	12.46
1991	$	72,662	35.5	89	100.00%	$	72,662	0.7053	$ 51,249	11.79
1990	$	105,364	36.5	91	100.00%	$	105,364	0.7162	$ 75,462	11.35
1989	$	89,824	37.5	94	100.00%	$	89,824	0.7319	$ 65,743	10.72
1988	$	82,978	38.5	96	100.00%	$	82,978	0.7420	$ 61,570	10.32
1987	$	60,192	39.5	99	100.00%	$	60,192	0.7564	$ 45,530	9.74
1986	$	60,665	40.5	101	100.00%	$	60,665	0.7656	$ 46,445	9.38
1985	$	60,879	41.5	104	100.00%	$	60,879	0.7787	$ 47,407	8.85
1984	$	62,983	42.5	106	100.00%	$	62,983	0.7870	$ 49,568	8.52
1983	$	26,245	43.5	109	100.00%	$	26,245	0.7988	$ 20,964	8.05
1982	$	29,331	44.5	111	100.00%	$	29,331	0.8063	$ 23,650	7.75
1981	$	29,076	45.5	114	100.00%	$	29,076	0.8169	$ 23,752	7.32
1980	$	18,182	46.5	116	100.00%	$	18,182	0.8236	$ 14,974	7.06
1979	$	16,778	47.5	119	100.00%	$	16,778	0.8331	$ 13,978	6.68
1978	$	9,342	48.5	121	100.00%	$	9,342	0.8391	$ 7,839	6.44
1977	$	11,538	49.5	124	100.00%	$	11,538	0.8478	$ 9,782	6.09
1976	$	32,308	50.5	126	100.00%	$	32,308	0.8532	$ 27,566	5.87
1975	$	10,172	51.5	129	100.00%	$	10,172	0.8612	$ 8,760	5.55
1974	$	5,725	52.5	131	100.00%	$	5,725	0.8663	$ 4,960	5.35
1973	$	5,521	53.5	134	100.00%	$	5,521	0.8737	$ 4,824	5.05
1972	$	8,209	54.5	136	100.00%	$	8,209	0.8785	$ 7,211	4.86
1971	$	23,946	55.5	139	100.00%	$	23,946	0.8856	$ 21,207	4.58
1970	$	3,013	56.5	141	100.00%	$	3,013	0.8902	$ 2,682	4.39
1969	$	5,894	57.5	144	100.00%	$	5,894	0.8971	$ 5,287	4.12
1968	$	9,865	58.5	146	100.00%	$	9,865	0.9015	$ 8,893	3.94
1967	$	14,239	59.5	149	100.00%	$	14,239	0.9081	$ 12,930	3.68
1966	$	11,637	60.5	151	100.00%	$	11,637	0.9125	$ 10,619	3.50
1965	$	6,143	61.5	154	100.00%	$	6,143	0.9190	$ 5,646	3.24
1964	$	6,621	62.5	156	100.00%	$	6,621	0.9234	$ 6,114	3.06
1963	$	2,503	63.5	159	100.00%	$	2,503	0.9302	$ 2,328	2.79
1962	$	3,190	64.5	161	100.00%	$	3,190	0.9349	$ 2,982	2.60
1961	$	4,120	65.5	164	100.00%	$	4,120	0.9424	$ 3,883	2.30
1960	$	2,946	66.5	166	100.00%	$	2,946	0.9477	$ 2,792	2.09
1959	$	19,343	67.5	169	100.00%	$	19,343	0.9559	$ 18,490	1.76
1958	$	4,632	68.5	171	100.00%	$	4,632	0.9614	$ 4,453	1.54
1957	$	2,713	69.5	174	100.00%	$	2,713	0.9694	$ 2,630	1.22
1956	$	8,505	70.5	176	100.00%	$	8,505	0.9745	$ 8,288	1.02
1955	$	4,087	71.5	179	100.00%	$	4,087	0.9823	$ 4,015	0.71
1954	$	6,384	72.5	181	100.00%	$	6,384	0.9865	$ 6,298	0.54
1953	$	30,652	73.5	184	100.00%	$	30,652	0.9950	$ 30,499	0.20
1952	$	1,126	74.5	186	100.00%	$	1,126	1.0000	$ 1,126	0.00
1951	$	1,768	75.5	189	100.00%	$	1,768	1.0000	$ 1,768	0.00
1950	$	8,487	76.5	191	100.00%	$	8,487	1.0000	$ 8,487	0.00
1949	$	22,186	77.5	194	100.00%	$	22,186	1.0000	$ 22,186	0.00
1948	$	-	78.5	196	100.00%	$	-	1.0000	$ -	0.00
1947	$	684	79.5	199	100.00%	$	684	1.0000	$ 684	0.00
1946	$	108	80.5	201	100.00%	$	108	1.0000	$ 108	0.00
1945	$	-	81.5	204	100.00%	$	-	1.0000	$ -	0.00

1944	$	-	82.5	206	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	209	100.00%	$	-	1.0000	$	-	0.00
1942	$	-	84.5	211	100.00%	$	-	1.0000	$	-	0.00
1941	$	93	85.5	214	100.00%	$	93	1.0000	$	93	0.00
1940	$	-	86.5	216	100.00%	$	-	1.0000	$	-	0.00
1939	$	114	87.5	219	100.00%	$	114	1.0000	$	114	0.00
1938	$	70	88.5	221	100.00%	$	70	1.0000	$	70	0.00
1937	$	702	89.5	224	100.00%	$	702	1.0000	$	702	0.00
1936	$	180	90.5	226	100.00%	$	180	1.0000	$	180	0.00
1935	$	340	91.5	229	100.00%	$	340	1.0000	$	340	0.00
1934	$	-	92.5	231	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	234	100.00%	$	-	1.0000	$	-	0.00
1932	$	180	94.5	236	100.00%	$	180	1.0000	$	180	0.00
1931	$	862	95.5	239	100.00%	$	862	1.0000	$	862	0.00
1930	$	576	96.5	241	100.00%	$	576	1.0000	$	576	0.00
1929	$	402	97.5	244	100.00%	$	402	1.0000	$	402	0.00
1928	$	32	98.5	246	100.00%	$	32	1.0000	$	32	0.00
1927	$	266	99.5	249	100.00%	$	266	1.0000	$	266	0.00
1926	$	8	100.5	251	100.00%	$	8	1.0000	$	8	0.00
1925	$	-	101.5	254	100.00%	$	-	1.0000	$	-	0.00
1924	$	9,129	102.5	256	100.00%	$	9,129	1.0000	$	9,129	0.00
1923	$	-	103.5	259	100.00%	$	-	1.0000	$	-	0.00
1922	$	142	104.5	261	100.00%	$	142	1.0000	$	142	0.00
1921	$	-	105.5	264	100.00%	$	-	1.0000	$	-	0.00
1920	$	65	106.5	266	100.00%	$	65	1.0000	$	65	0.00
1919	$	312	107.5	269	100.00%	$	312	1.0000	$	312	0.00
1918	$	-	108.5	271	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	274	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	276	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	279	100.00%	$	-	1.0000	$	-	0.00
1914	$	0	112.5	281	100.00%	$	0	1.0000	$	-	0.00
1913	$	-	113.5	284	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	286	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	289	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	291	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	294	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	296	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	299	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	301	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	304	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	306	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	309	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	311	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	314	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	316	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	319	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	321	100.00%	$	-	1.0000	$	-	0.00
1897	$	-	129.5	324	100.00%	$	-	1.0000	$	-	0.00
1896	$	-	130.5	326	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	329	100.00%	$	-	1.0000	$	-	0.00

1894	$ -	132.5	331	100.00%	$ -	1.0000	$ -	0.00
1893	$ -	133.5	334	100.00%	$ -	1.0000	$ -	0.00
1892	$ -	134.5	336	100.00%	$ -	1.0000	$ -	0.00
1891	$ -	135.5	339	100.00%	$ -	1.0000	$ -	0.00
1890	$ -	136.5	341	100.00%	$ -	1.0000	$ -	0.00
1889	$ -	137.5	344	100.00%	$ -	1.0000	$ -	0.00
1888	$ -	138.5	346	100.00%	$ -	1.0000	$ -	0.00
1887	$ -	139.5	349	100.00%	$ -	1.0000	$ -	0.00
1886	$ -	140.5	351	100.00%	$ -	1.0000	$ -	0.00
1885	$ -	141.5	354	100.00%	$ -	1.0000	$ -	0.00
1884	$ -	142.5	356	100.00%	$ -	1.0000	$ -	0.00
1883	$ -	143.5	359	100.00%	$ -	1.0000	$ -	0.00
1882	$ -	144.5	361	100.00%	$ -	1.0000	$ -	0.00
Total	$ 5,308,206				$ 5,308,206		$ 2,508,852	

Net Salvage Value	0%	
Theoretical Reserve Including Net Salvage	$ 2,508,852	
Average Remaining Life		21.09
Theoretical Reserve %	47.26%	

UGI - Gas Division
OCA Depreciation Study Adjustments
Based on Plant In Service as of September 30, 2026
Remaining Life Analysis

Account Number **38710**
Plant Account **OTHER EQUIPMENT - GRAPHIC DATA BASE**

Survivor Curve SQ
Average Service Life 25
Net Salvage 0%
Study Year 2026

Year	Original Cost ($)	Age (years)	Age as % of ASL	Percent Surviving per Curve	Plant Surviving at FYE 2024 ($)	Reserve Ratio per Curve	Theoretical Reserve ($)	Remaining Life (yrs)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
2026	$ -	0.5	2	100.00%	$ -	0.0150	$ -	24.63
2025	$ -	1.5	6	100.00%	$ -	0.0550	$ -	23.63
2024	$ -	2.5	10	100.00%	$ -	0.0950	$ -	22.63
2023	$ -	3.5	14	100.00%	$ -	0.1350	$ -	21.63
2022	$ -	4.5	18	100.00%	$ -	0.1750	$ -	20.63
2021	$ -	5.5	22	100.00%	$ -	0.2150	$ -	19.63
2020	$ -	6.5	26	100.00%	$ -	0.2550	$ -	18.63
2019	$ -	7.5	30	100.00%	$ -	0.2950	$ -	17.63
2018	$ -	8.5	34	100.00%	$ -	0.3350	$ -	16.63
2017	$ -	9.5	38	100.00%	$ -	0.3750	$ -	15.63
2016	$ -	10.5	42	100.00%	$ -	0.4150	$ -	14.63
2015	$ -	11.5	46	100.00%	$ -	0.4550	$ -	13.63
2014	$ -	12.5	50	100.00%	$ -	0.4950	$ -	12.63
2013	$ -	13.5	54	100.00%	$ -	0.5350	$ -	11.63
2012	$ -	14.5	58	100.00%	$ -	0.5750	$ -	10.63
2011	$ -	15.5	62	100.00%	$ -	0.6150	$ -	9.63
2010	$ -	16.5	66	100.00%	$ -	0.6550	$ -	8.63
2009	$ -	17.5	70	100.00%	$ -	0.6950	$ -	7.63
2008	$ -	18.5	74	100.00%	$ -	0.7350	$ -	6.63
2007	$ -	19.5	78	100.00%	$ -	0.7750	$ -	5.63
2006	$ -	20.5	82	100.00%	$ -	0.8150	$ -	4.63
2005	$ -	21.5	86	100.00%	$ -	0.8550	$ -	3.63
2004	$ -	22.5	90	100.00%	$ -	0.8950	$ -	2.63
2003	$ 93,599	23.5	94	100.00%	$ 93,599	0.9350	$ 87,515	1.63
2002	$ 7,564	24.5	98	100.00%	$ 7,564	0.9750	$ 7,375	0.63
2001	$ 13,979	25.5	102	100.00%	$ 13,979	1.0000	$ 13,979	0.00
2000	$ -	26.5	106	100.00%	$ -	1.0000	$ -	0.00
1999	$ -	27.5	110	100.00%	$ -	1.0000	$ -	0.00
1998	$ 10,727	28.5	114	100.00%	$ 10,727	1.0000	$ 10,727	0.00
1997	$ -	29.5	118	100.00%	$ -	1.0000	$ -	0.00
1996	$ -	30.5	122	100.00%	$ -	1.0000	$ -	0.00
1995	$ 4,075	31.5	126	100.00%	$ 4,075	1.0000	$ 4,075	0.00
1994	$ -	32.5	130	100.00%	$ -	1.0000	$ -	0.00

1993	$	515	33.5	134	100.00%	$	515	1.0000	$	515	0.00
1992	$	3,540	34.5	138	100.00%	$	3,540	1.0000	$	3,540	0.00
1991	$	1,588	35.5	142	100.00%	$	1,588	1.0000	$	1,588	0.00
1990	$	11,535	36.5	146	100.00%	$	11,535	1.0000	$	11,535	0.00
1989	$	77,363	37.5	150	100.00%	$	77,363	1.0000	$	77,363	0.00
1988	$	167,324	38.5	154	100.00%	$	167,324	1.0000	$	167,324	0.00
1987	$	112,022	39.5	158	100.00%	$	112,022	1.0000	$	112,022	0.00
1986	$	113,889	40.5	162	100.00%	$	113,889	1.0000	$	113,889	0.00
1985	$	109,976	41.5	166	100.00%	$	109,976	1.0000	$	109,976	0.00
1984	$	103,914	42.5	170	100.00%	$	103,914	1.0000	$	103,914	0.00
1983	$	92,573	43.5	174	100.00%	$	92,573	1.0000	$	92,573	0.00
1982	$	328,563	44.5	178	100.00%	$	328,563	1.0000	$	328,563	0.00
1981	$	184,018	45.5	182	100.00%	$	184,018	1.0000	$	184,018	0.00
1980	$	53,900	46.5	186	100.00%	$	53,900	1.0000	$	53,900	0.00
1979	$	-	47.5	190	100.00%	$	-	1.0000	$	-	0.00
1978	$	-	48.5	194	100.00%	$	-	1.0000	$	-	0.00
1977	$	-	49.5	198	100.00%	$	-	1.0000	$	-	0.00
1976	$	-	50.5	202	100.00%	$	-	1.0000	$	-	0.00
1975	$	-	51.5	206	100.00%	$	-	1.0000	$	-	0.00
1974	$	-	52.5	210	100.00%	$	-	1.0000	$	-	0.00
1973	$	-	53.5	214	100.00%	$	-	1.0000	$	-	0.00
1972	$	-	54.5	218	100.00%	$	-	1.0000	$	-	0.00
1971	$	-	55.5	222	100.00%	$	-	1.0000	$	-	0.00
1970	$	-	56.5	226	100.00%	$	-	1.0000	$	-	0.00
1969	$	-	57.5	230	100.00%	$	-	1.0000	$	-	0.00
1968	$	-	58.5	234	100.00%	$	-	1.0000	$	-	0.00
1967	$	-	59.5	238	100.00%	$	-	1.0000	$	-	0.00
1966	$	-	60.5	242	100.00%	$	-	1.0000	$	-	0.00
1965	$	-	61.5	246	100.00%	$	-	1.0000	$	-	0.00
1964	$	-	62.5	250	100.00%	$	-	1.0000	$	-	0.00
1963	$	-	63.5	254	100.00%	$	-	1.0000	$	-	0.00
1962	$	-	64.5	258	100.00%	$	-	1.0000	$	-	0.00
1961	$	-	65.5	262	100.00%	$	-	1.0000	$	-	0.00
1960	$	-	66.5	266	100.00%	$	-	1.0000	$	-	0.00
1959	$	-	67.5	270	100.00%	$	-	1.0000	$	-	0.00
1958	$	-	68.5	274	100.00%	$	-	1.0000	$	-	0.00
1957	$	-	69.5	278	100.00%	$	-	1.0000	$	-	0.00
1956	$	-	70.5	282	100.00%	$	-	1.0000	$	-	0.00
1955	$	-	71.5	286	100.00%	$	-	1.0000	$	-	0.00
1954	$	-	72.5	290	100.00%	$	-	1.0000	$	-	0.00
1953	$	-	73.5	294	100.00%	$	-	1.0000	$	-	0.00
1952	$	-	74.5	298	100.00%	$	-	1.0000	$	-	0.00
1951	$	-	75.5	302	100.00%	$	-	1.0000	$	-	0.00
1950	$	-	76.5	306	100.00%	$	-	1.0000	$	-	0.00
1949	$	-	77.5	310	100.00%	$	-	1.0000	$	-	0.00
1948	$	-	78.5	314	100.00%	$	-	1.0000	$	-	0.00
1947	$	-	79.5	318	100.00%	$	-	1.0000	$	-	0.00
1946	$	-	80.5	322	100.00%	$	-	1.0000	$	-	0.00
1945	$	-	81.5	326	100.00%	$	-	1.0000	$	-	0.00
1944	$	-	82.5	330	100.00%	$	-	1.0000	$	-	0.00
1943	$	-	83.5	334	100.00%	$	-	1.0000	$	-	0.00

1942	$	-	84.5	338	100.00%	$	-	1.0000	$	-	0.00
1941	$	-	85.5	342	100.00%	$	-	1.0000	$	-	0.00
1940	$	-	86.5	346	100.00%	$	-	1.0000	$	-	0.00
1939	$	-	87.5	350	100.00%	$	-	1.0000	$	-	0.00
1938	$	-	88.5	354	100.00%	$	-	1.0000	$	-	0.00
1937	$	-	89.5	358	100.00%	$	-	1.0000	$	-	0.00
1936	$	-	90.5	362	100.00%	$	-	1.0000	$	-	0.00
1935	$	-	91.5	366	100.00%	$	-	1.0000	$	-	0.00
1934	$	-	92.5	370	100.00%	$	-	1.0000	$	-	0.00
1933	$	-	93.5	374	100.00%	$	-	1.0000	$	-	0.00
1932	$	-	94.5	378	100.00%	$	-	1.0000	$	-	0.00
1931	$	-	95.5	382	100.00%	$	-	1.0000	$	-	0.00
1930	$	-	96.5	386	100.00%	$	-	1.0000	$	-	0.00
1929	$	-	97.5	390	100.00%	$	-	1.0000	$	-	0.00
1928	$	-	98.5	394	100.00%	$	-	1.0000	$	-	0.00
1927	$	-	99.5	398	100.00%	$	-	1.0000	$	-	0.00
1926	$	-	100.5	402	100.00%	$	-	1.0000	$	-	0.00
1925	$	-	101.5	406	100.00%	$	-	1.0000	$	-	0.00
1924	$	-	102.5	410	100.00%	$	-	1.0000	$	-	0.00
1923	$	-	103.5	414	100.00%	$	-	1.0000	$	-	0.00
1922	$	-	104.5	418	100.00%	$	-	1.0000	$	-	0.00
1921	$	-	105.5	422	100.00%	$	-	1.0000	$	-	0.00
1920	$	-	106.5	426	100.00%	$	-	1.0000	$	-	0.00
1919	$	-	107.5	430	100.00%	$	-	1.0000	$	-	0.00
1918	$	-	108.5	434	100.00%	$	-	1.0000	$	-	0.00
1917	$	-	109.5	438	100.00%	$	-	1.0000	$	-	0.00
1916	$	-	110.5	442	100.00%	$	-	1.0000	$	-	0.00
1915	$	-	111.5	446	100.00%	$	-	1.0000	$	-	0.00
1914	$	-	112.5	450	100.00%	$	-	1.0000	$	-	0.00
1913	$	-	113.5	454	100.00%	$	-	1.0000	$	-	0.00
1912	$	-	114.5	458	100.00%	$	-	1.0000	$	-	0.00
1911	$	-	115.5	462	100.00%	$	-	1.0000	$	-	0.00
1910	$	-	116.5	466	100.00%	$	-	1.0000	$	-	0.00
1909	$	-	117.5	470	100.00%	$	-	1.0000	$	-	0.00
1908	$	-	118.5	474	100.00%	$	-	1.0000	$	-	0.00
1907	$	-	119.5	478	100.00%	$	-	1.0000	$	-	0.00
1906	$	-	120.5	482	100.00%	$	-	1.0000	$	-	0.00
1905	$	-	121.5	486	100.00%	$	-	1.0000	$	-	0.00
1904	$	-	122.5	490	100.00%	$	-	1.0000	$	-	0.00
1903	$	-	123.5	494	100.00%	$	-	1.0000	$	-	0.00
1902	$	-	124.5	498	100.00%	$	-	1.0000	$	-	0.00
1901	$	-	125.5	502	100.00%	$	-	1.0000	$	-	0.00
1900	$	-	126.5	506	100.00%	$	-	1.0000	$	-	0.00
1899	$	-	127.5	510	100.00%	$	-	1.0000	$	-	0.00
1898	$	-	128.5	514	100.00%	$	-	1.0000	$	-	0.00
1897	$	-	129.5	518	100.00%	$	-	1.0000	$	-	0.00
1896	$	-	130.5	522	100.00%	$	-	1.0000	$	-	0.00
1895	$	-	131.5	526	100.00%	$	-	1.0000	$	-	0.00
1894	$	-	132.5	530	100.00%	$	-	1.0000	$	-	0.00
1893	$	-	133.5	534	100.00%	$	-	1.0000	$	-	0.00
1892	$	-	134.5	538	100.00%	$	-	1.0000	$	-	0.00

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, James S. Garren, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 4, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 13, 2026

Signature: /s/ *James S. Garren*
James S. Garren

Address: 1850 Parkway Place, Suite 800
Marietta, GA 30067

BEFORE THE

PENNSYLVANIA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PENNSYLVANIA PUBLIC UTILITY COMMISSION V. UGI UTILITIES, INC. – GAS DIVISION	* * * * *	**DOCKET NUMBER R-2025-3059523, et al.**

SURREBUTTAL TESTIMONY AND EXHIBITS

OF

JAMES S. GARREN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2026

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I. INTRODUCTION

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

A. My name is James S. Garren. I am a Senior Manager of the firm NewGen Strategies and Solutions LLC ("NewGen"). My business address is 225 Union Boulevard, Suite 450, Lakewood, CO 80228.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Exhibit JSG-1 is a summary of my qualifications and experience.

Q. PLEASE DESCRIBE YOUR BACKGROUND IN UTILITY DEPRECIATION.

A. Since 2010, I have been employed in the utility consulting field, beginning my career as an analyst with Snavely King Majoros & Associates, Inc. My early work focused on depreciation studies, where I supported Michael J. Majoros in preparing testimony and exhibits for depreciation proceedings. In 2014, I became the firm's primary expert on depreciation matters. Since that time, I have presented testimony in numerous depreciation rate cases across the United States, addressing issues such as service life estimation, net salvage analysis, reserve analysis, and related depreciation topics. In 2015, I earned the designation of Certified Depreciation Professional from the Society of Depreciation Professionals.[1] From 2022 to 2025, I served as a Project Manager with GDS Associates, Inc., continuing my work as a depreciation expert. In October 2025, I joined NewGen, where I continue to provide expert analysis and testimony on depreciation issues.

[1] https://www.depr.org/page/Certification

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of this Surrebuttal Testimony is to rebut several of the arguments raised by UGI Gas Division's ("UGI-Gas") Witness John F. Wiedmayer in his Rebuttal Testimony, which referenced several issues stemming from my Direct Testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). I will be addressing two points that Mr. Wiedmayer makes in his Rebuttal Testimony:

- The arguments for Equal Life Group ("ELG") method
- The impact of ELG v. Average Life Group ("ALG") on Rate Base
- The historic use and adoption of the ELG procedure.
- "Errors" in my calculations.
- Average Service Lives

Q. HAS MR. WIEDMAYER RAISED ANY NOVEL ARGUMENTS IN HIS REBUTTAL TESTIMONY THAT YOU FIND PERSUASIVE REGARDING THE CONTINUED USE OF THE ELG PROCEDURE FOR CALCULATING REMAINING LIFE?

A No. As I stated in my direct testimony, the ELG procedure does have the benefit of being a theoretically superior procedure for allocating the cost of plant investment, because it tracks the retirement patterns. However, it suffers from several shortcomings. Principally, while ELG is precise in how it tracks retirement rates, but that requires more regular updates to the rates, because the ELG procedure is more precise than the underlying estimates themselves are presumed to be accurate.

Figure 2 of Mr. Wiedmayer's explains this precision accurately. I do not dispute that the ELG method is more precise, for a given life and retirement curve. Figure 2 correctly projects the expected life of a single vintage over time. However, the 45-R2 life and curve depicted are not the true underlying life of that plant. They are an estimate based on the information available at a given time. If we update our estimate in five years, changing from a R2 curve to an R1 curve, then the entire calculation changes, and the precision achieved based on the previous estimate is squandered, because while ELG is precise, that precision is harmful if our estimates change over time.

Thus, the administrative work of reviewing the rates does not yield more accurate rates, it only causes rates to fluctuate more as estimates change over time. If our overall life estimates were perfectly accurate and consistent, then the precision gained by the use of the ELG method might be worthwhile, but in reality, life estimates change over time for all kinds of reasons, including changes to technology, maintenance and simple improvement of data over the life of a given account.

Secondarily, while ELG does not represent accelerated depreciation in the sense of being a non-linear recover method, it does accelerate rates necessarily relative to the ALG method. As we will address next, this relative acceleration can become permanent when plant grows over time.

Q. WHAT ISSUE DO YOU TAKE WITH MR. WIEDMAYER'S RATE BASE ANALYSIS UNDER THE ELG AND ALG PROCEDURES?

A. In Figure 3 of his surrebuttal testimony, Mr. Wiedmayer provides a graph and table of the effect that the two remaining life procedures, and this graph and subsequent tables purport to show that under the ALG procedure, the resulting revenue requirement will exceed the

revenue requirement in 2038. However, analysis of JFW-1R, shows how this graph and table were calculated, and it is clear that Mr. Wiedmayer's analysis is based on a highly flawed assumption regarding the growth rate of plant in service in the period being analyzed. As I show below, the growth rate Mr. Wiedmayer estimates does not track UGI-Gas's actual plant growth over the three period shown in this rate case.

According to this exhibit, Mr. Wiedmayer's analysis begins with an initial average Original cost of $5,936,133,917 in 2026, and ends with a balance of $9,663,381,416 in 2025. Based on this, using a standard Compound Annual Growth Rate ("CAGR") formula, the average growth rate Mr. Wiedmayer assumes is just under 2.05%.

(9,663,381,416/5,936,133,917)^(1/24) - 1 ≈ 2.05%.

Q. WHAT HAS UGI'S GROWTH RATE BEEN OVER THE THREE PERIODS ENCOMPASSED BY THE CURRENT FILING?

However, what we actually see in the Company's filing is that UGI-Gas's original cost for depreciable gas plant for its HTY of 2025 was $5,526,564,704 and increased to $5,908,417,996 in the FTY of 2026 and then to $6,365,028,307 in the FPFTY of 2027. If we put the starting and ending balances into the CAGR formula, we arrive at the following:

$(6,365,028,307/5,526,564,704)^{1/2} – 1 = ~7.32%

While the three years contained in UGI-Gas's filing may not be representative of the future, the magnitude of the difference between Mr. Wiedmayer's assumed growth rate and the actual growth rate we see is large enough that even assuming a somewhat lower average growth rate over a longer period, it should be clear that Mr. Wiedmayer's example is flawed.

This is significant, because the rate at which the balance between the outcomes under ELG and ALG are very sensitive to this growth rate. Recall that under ELG, plant will tend to depreciate much faster earlier in its life, and then depreciation slows down as it approaches the end of its life, relative to the ALG procedure. If you are adding a minimal amount of new plant each year, then overall you expect that the two procedures will balance out more quickly.

If, on the other hand, you are adding a significant amount to plant in each year, you are increasing the percentage of the plant that is at this Age 0, faster depreciation rate, owing to the ELG procedure. Mr. Wiedmayer's example, intended to make the ELG procedure appear more reasonable than it is, significantly understates the CAGR for this exact reason. In reality, as the plant grows more year over year, not only can the "evening out" period be pushed back further, but the curves can, in fact, become parallel or diverge such that the ALG procedure will never produce a higher revenue requirement than under the ELG procedure.

Q. CAN YOU PROVIDE SOME INSIGHT INTO THE HISTORIC USE OF THE ELG METHOD?

A. Yes. The examples cited in Mr. Wiedmayer's testimony are the exceptions and not the general practice. As Mr. Wiedmayer notes, the ELG procedure was widely adopted across the telecommunications industry in the 80s.[2] Pennsylvania adopted the procedure at that time across the state. However, the ELG procedure was not widely adopted in other industries. As telecommunications was largely de-regulated in the 1990s, the ELG

[2] Wiedmayer Rebuttal testimony, page 15.

method fell out of use broadly, and it is now currently only used on a state-wide basis in Pennsylvania, to the best of my knowledge. While I am aware of one other state, Indiana, which uses ELG intermittently, has not been widely adopted and my understanding is that the Indiana Utility Regulatory Commission ("IURC") has recently rejected its use in at least one case.

The examples cited in Mr. Wiedmayer's testimony are the exceptions, and the ELG procedure is not a particularly long-standing practice and is not widely used in any of the major utility industries. This is precisely why, despite having testified on the subject of depreciation for over a decade in over a dozen jurisdictions, including the Federal Energy Regulatory Commission, I have not had to utilize ELG calculations. They are not widely used, and I would not recommend their use.

Q. DO YOU BELIEVE THAT YOUR TESTIMONY CONTAINS "ERRORS" AS MR. WIEDMAYERT ASSERTS?

A. I do not believe that my testimony or exhibits contain substantive errors. I do note, as Mr. Wiedmayer has pointed out, that my depreciation calculation shown in Exhibit JSG-2 appears to note the average service life and curve used for Account 378 as a 48-S0, which would be unchanged from Mr. Wiedmayer's proposed life and curve for this account. However, the actual life and curve used to calculate my remaining life for this account are the 53-R0.5 life and curve. This is what is noted and discussed in my testimony, and the calculated remaining life and rate are correct. The error is superficial, though regrettable.

As to the more substantive error. Mr. Wiedmayer states that by failing to recalculate the accumulated depreciation for all three periods in order to calculate the rates, I have made

an error.[3] It is true that I have declined to calculate my adjustments to depreciation rates and expenses for all three periods. I regard my role in proposing adjustments to depreciation to be to critique the underlying methods, procedures and proposed life and net salvage parameters that are used in the calculation of depreciation rates. Given my adjustments, I attempt to calculate the magnitude of the impact of the resulting adjustments on overall depreciation expense, so that their revenue requirement impacts can be reviewed by the Commission. However, this is an estimate of the impact of my underlying adjustments. I cannot, in the time allotted by a rate case, ensure that the calculation of depreciation expense is precisely what should be reflected in the Company's tariff. Rather, given the arguments raised regarding the adjustments I have proposed to the methods, procedures and parameters, the Commission must determine what it believes that appropriate outcome is, and then depreciation rates and expenses can be calculated in the prescribed manner.

This is not an error on my part, but an acknowledgement of the limitations and appropriate focus of a rate case.

Q. DO YOU HAVE ANY COMMENTS ON MR. WIEDMAYER'S DISCUSSION OF YOUR AVERAGE SERVICE LIFE RECOMMENDATIONS?

A. Yes. I have several thoughts on Mr. Wiedmayer's discussion of service lives, and I would like to address several of his statements briefly.

1. "*It is unclear. Mr. Garren states in his testimony that the service life analysis was conducted as of the future test year, September 30, 2026. However, he provides no support for this study. He also claims to have used the results of the Company's service life study which was submitted to the Commission in 2023 using plant accounting data*

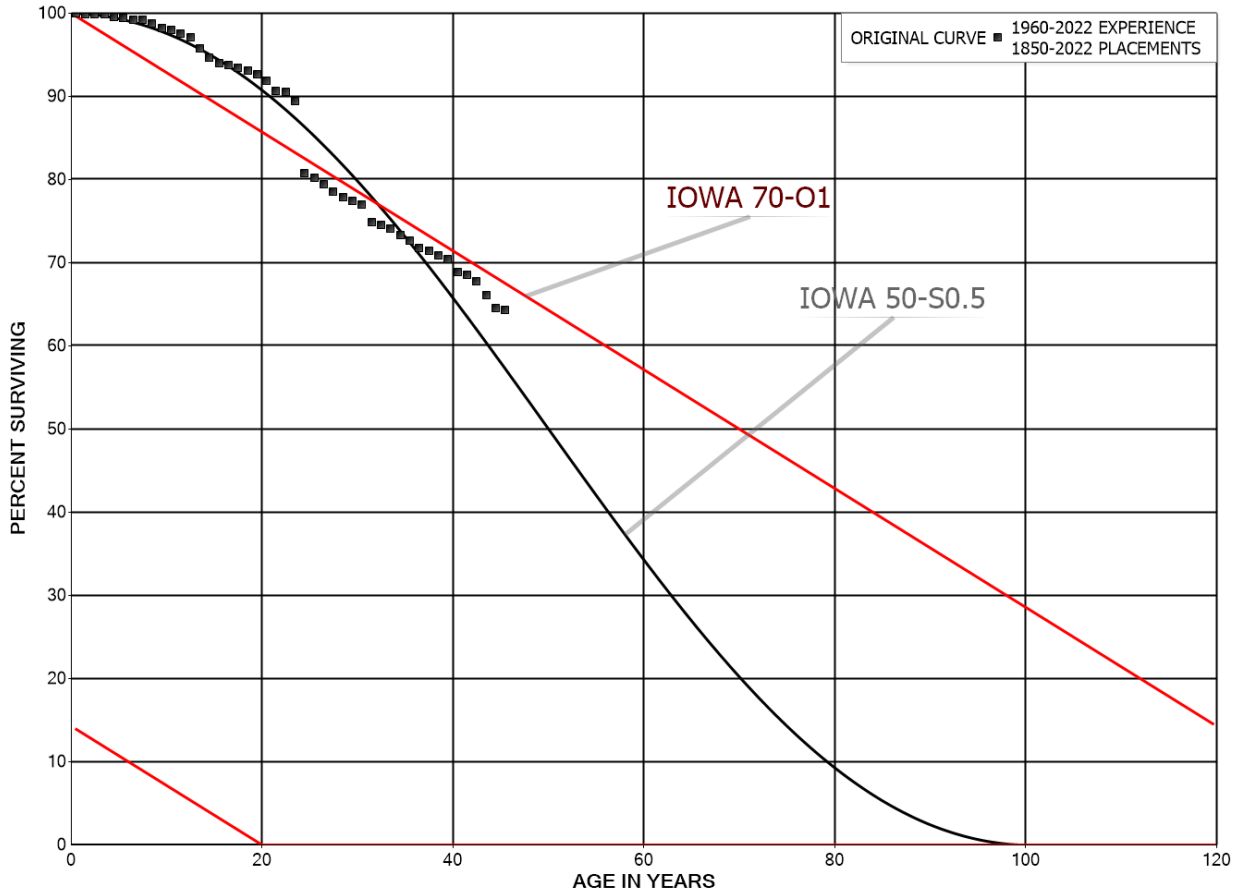
[3] Weidmayer rebuttal testimony pages 28-29.

through September Irrespective of these items, OCA Witness Garren proposes different survivor curves for three accounts and describes those selections in narrative form"[4]

Here, Mr. Wiedmayer appears to genuinely not understand how my proposed survivor curves could differ from his proposed life and curve. However, I believe that my testimony is quite clear, which is that I have utilized the data, tables and mathematical analysis provided in Mr. Wiedmayer's study, and have used that data and analysis to arrive at different conclusions. I do not believe that Mr. Wiedmayer's study supports his conclusions, and I believe, further, that he consistently misrepresents the results of his study in order to make his conclusions appear

[4] Wiedmayer rebuttal testimony, page 33.

more reasonable than they are.



To take this graph, presented for Account 375.00 – Structures and Improvements as an example, we can see that according to this graph, the data Mr. Wiedmayer presents ends at approximately age 46.6. This is the line from Mr. Wiedmayer's OLT for the ages 45.5-47.5:

45.5	1,549,067	10,423	0.0067	0.9933	64.25
46.5	1,618,271	3,036	0.0019	0.9981	63.82
47.5	1,638,365	4,542	0.0028	0.9972	63.70

Note that the exposures here at the end of the segment of ages is $1.6 million, and the percent surviving at age 47.6 is 63.7%. For reference, exposures at age 0.0 for this OLT are only $5.2 million. The remaining $1.6 million is still a significant amount of

exposures, relative to the overall data in the account. However, Mr. Wiedmayer would have us think is the last "significant" data point in his OLT.

Now, here is the portion of that same OLT twenty ages further down the table, from 65.5 – 67.5:

65.5	1,046,827	8,035	0.0077	0.9923	54.77
66.5	1,001,774	9,895	0.0099	0.9901	54.35
67.5	984,182	10,621	0.0108	0.9892	53.81

As we can see, here the exposures have only dropped by slightly over a third, and the percent surviving at age 67.5 is 54.81%. These data points have been completely omitted from Mr. Wiedmayer's presented graph, and it is not difficult to see why he does not wish to highlight them. Referring back to Mr. Wiedmayer's graph above, his proposed 50-S0.5 life and curve would predict that the percent surviving at age age 66.5 should be approximately 26-27%. At the same time, my proposed 70-O1 curve would predict that the percent surviving at age 66.5 should be approximately 54-55%, which is exactly what is show in the actual historical data for UGI-Gas, which Mr. Wiedmayer has omitted from his presented graphs.

These are not insignificant data points. At age 66.5, the exposures are 20% of the total age 0.0 exposures, and just under 66% of exposures for the last data point Mr. Weidmayer judges to be 'significant'.

Reviewing the graphs and OLT presented for each account yields the same concerning omissions, and this explains how my proposals can be based on the depreciation study and data Mr. Wiedmayer submitted in this case, and result in very different conclusions.

2. *"Given my prior comment that the average service life for gas distribution accounts typically change gradually in 1 to 3 year increments, a five year increase in service life proposed by Mr. Garren seems unreasonable."*[5]

I am not aware of any authoritative text, nor have I ever seen a study that supports this statement. Mr. Wiedmayer is to the best of my knowledge simply averring that a five-year increase in lives is unreasonable. In my experience, it is quite commonplace to increase propose average service lives by five years.

What I believe Mr. Wiedmayer might be attempting to claim is that the "true" underlying service life for a given account likely shifts in 1 to 3 year increments over time. This leaves one to wonder what the frequency of these 1 to 3 year increments occur over, but this is not made clear.

However, more to the point, why it may be the case that the "true" underlying service life will only shift gradually over time with company practices, we do not actually have access to this "true" average service life. We have estimates that are based on data, and it is certainly reasonable for an two different estimates to be quite far apart. That is to say that my estimate of 53 years is 5 years longer than Mr. Wiedmayer's estimate of 48 years. That is not to say that I believe that in the time since the previous proposed life was adopted, the "true" underlying average service life for this account has shifted by 5 years. Rather, it is the case that I am suggesting the previously adopted 48-year average service life was some amount too short in the first place.

Mr. Wiedmayer's standard of 1 to 3 year increments is vague and unsupported, and I do not believe his understanding of my proposal is clear.

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[5] Wiedmayer rebuttal testimony, page 39.

3. *"As stated previously, Mr. Garren does not present an independent UGI Gas service life study comparable to the one the Company filed in this proceeding. Although he devotes substantial portions of his testimony to general service life theory, actuarial concepts, and mathematical curve fitting, he does not present the actual results of a separate UGI Gas actuarial study (including original life tables as of the FTY) showing how his proposed survivor curves were derived."*[6]

This is absolutely true. However, rather than representing a weakness of my testimony and conclusions, I believe that it is a strength. I have not presented a separate service life analysis. The Commission does not need to compare my analysis to Mr. Wiedmayer's analysis and determine which actuarial analysis is more accurate or superior on the technical merits. I have clearly explained that Mr. Wiedmayer's analysis does not support his own conclusions regarding average service life, and worse, that his testimony misrepresents and obfuscates the actuarial analysis he has conducted in order to support his conclusion rather than allow his proposals to be based on his analysis and/or clear justifications for deviating from that analysis.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes. It does.

[6] Wiedmayer rebuttal testimony, page 41-42.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v. Docket No. R-2025-3059523

UGI Utilities, Inc. - Gas Division

:

VERIFICATION

I, James S. Garren, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 4SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2026

Signature: /s/ *James S. Garren*
James S. Garren

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