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June 6, 2025

VIA ELECTRONIC FILING

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, Filing Room
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. Pike County Light & Power Company - Gas; Docket No. R-2024-3052357; **PCLP Pre-Served Testimony, Exhibits and Verifications**

Dear Secretary Homsher:

Enclosed for filing please find Pike County Light & Power Company – Gas Division's Pre-Served Testimony, Exhibits and Verifications admitted into the evidentiary record by Administrative Law Judges Marta Guhl and Alphonso Arnold III's May 29, 2025, Order Granting Joint Stipulation and Admitting Evidence:

Direct Testimony

1. PCLP Statement No. 1 – Direct Testimony of Paul M. Normand, including Exhibit Nos. G-6, G-7 and G-8.
2. PCLP Statement No. 2 – Direct Testimony of Accounting Panel (Charles Lenns and Matthew Lenns), including Exhibit Nos. G-1, G-2, G-3, EG4, G-5[1] and Verification of Customer Notice, Notice of Proposed Gas Rate Changes and Public Notice Gas Rates.
3. PCLP Statement No. 3 – Direct Testimony of Ed Verbraak (adopted by Nancy Karlovich)
4. Responses to Standard Data Requests.

[1] Please note that in Exhibit G-5, Schedules 2 and 3 were mislabeled but have been corrected for this submission.

Rebuttal Testimony

5. PCLP Statement No. 1-R – Rebuttal Testimony of Paul M. Normand, including Exhibit R - A.

6. PCLP Statement No. 2-R – Rebuttal Testimony of Accounting Panel (Charles Lenns and Matthew Lenns), including Pike AP-G Update (Schedule Nos. 1-12) and Exhibits AP-1R and AP-2R.

7. PCLP Statement No. 3-R – Direct Testimony of Nancy Karlovich.

8. PCLP Statement No. 4-R – Rebuttal Testimony of Christopher M. Wall, Principal, The Brattle Group, including Exhibit Nos. CMW-1R, CMW-2R, CMW-3R, CMW-4R, CMW-5R, CMW-6R, CMW-7R, CMW-8R, CMW-9R, CMW-10R, CMW-11R and CMW-12R.

9. PCLP Statement No. 5-R – Rebuttal Testimony of Charlene Faulk.

Rejoinder

10. PCLP Statement No. 3-RJ – Rejoinder Testimony of Nancy Karlovich.

Also attached are Testimony Verifications of Paul M. Normand, the Accounting Panel, Christopher M. Wall, Charlene Faulk and Nancy Karlovich.

Please note that in Pike Gas Statement No. 2 (Direct Testimony of Accounting Panel), Exhibit G-5, Schedules 2 and 3 were mislabeled but have been corrected for this submission.

If you have any questions, please contact me.

Very truly yours,

/s/ Whitney E. Snyder

Whitney E. Snyder
Erich W. Struble

Counsel for Pike County Light & Power Company

WES/das
Enclosures

cc: Administrative Law Judge Marta Guhl (mguhl@pa.gov)
Administrative Law Judge Alphonso Arnold III (alphonarno@pa.gov)
Pamela McNeal, Legal Assistant (pmcneal@pa.gov)
Per Certificate of Service

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:
	:
v.	: DOCKET NO. R-2024-xxxxxxx
	:
Pike County Light & Power Company (gas)	:

PIKE COUNTY LIGHT & POWER COMPANY

Statement No. 1

Direct Testimony of Paul M. Normand

Exhibit G-6 – Gas Embedded Cost of Service

Exhibit G-7 - Gas Cost of Service Proposed Revenues

Exhibit G-8 - Gas Rate Design Recommendations

Draft 12/27/24

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DIRECT TESTIMONY OF PAUL M. NORMAND
ON BEHALF OF
PIKE COUNTY LIGHT & POWER COMPANY

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DIRECT TESTIMONY OF PAUL M. NORMAND
ON BEHALF OF
PIKE COUNTY LIGHT & POWER COMNPANY

LIST OF EXHIBITS

EXHIBIT G-6 Gas Embedded Cost of Service

Exhibit G-6 Schedules	Description
PMN-1-G	Qualifications of Paul M. Normand
PMN-2-G	Gas Embedded Cost of Service Summary Results – Existing Rate of Return, Based on 12 Months Ended 09/30/2024 (Exhibit G-6, Summary)
PMN-3-G	Summary of Gas Revenue Requirements at Existing Rate of Return, Equalized Rate of Return, and at Proposed Revenue Levels.
PMN-4-G	Gas Embedded Cost of Service Detailed Results Based on 12 Months Ended 09/30/2024 (Exhibit G-6, Detail)
PMN-5-G	Gas Embedded Class Cost of Service – Unbundled Summary of Results – Existing Rate of Return, Based on 12 Months Ended 09/30/2024 – Proposed Equalized ROR, Based on 12 Months Ended 9/30/2025
PMN-6-G	Description of Gas Allocation Factors

EXHIBIT G-7 Gas Embedded Cost of Service Summary Results
– Proposed at Equalized ROR, Based on 12 Months Ended 06/30/2024

EXHIBIT G-8 Gas Rate Design and Bill Impact Analysis

INTRODUCTION

Q. Would the witness please state his name and business address?

A. Paul M. Normand, 1103 Rocky Drive, Suite 201, Reading, PA 19609.

Q. By whom are you employed and what position do you hold?

A. I am employed by Management Applications Consulting, Inc., and my position is management consultant and president of the firm.

Q. Please state your qualifications.

A. My qualifications are shown on Schedule PMN-1-G.

SCOPE OF TESTIMONY

Q. What is your responsibility in connection with this filing?

A. I am sponsoring the following three exhibits:

- Exhibit G-6, the Gas Embedded Cost of Service Study
- Exhibit G-7, the Gas Embedded Cost of Service Summary at Proposed Rates
- Exhibit G-8, the Gas Present and Proposed Rate Design.

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

A. My testimony will present:

1. The Pike County Light & Power Company ("Pike" or "Company") Gas Embedded Cost of Service ("COS") Study as of September 30, 2024;
2. The Company's Gas Embedded COS Study as of September 30, 2025;
3. The Company's proposal for revenue allocation and rate design; and
4. The impact of the proposed rate changes on customers' bills.

Q. Please describe the general arrangement of Exhibit G-6.

A. Exhibit G-6 consists of six schedules, Schedule PMN-1-G through PMN-6-G. Schedule PMN-1-G includes Paul M. Normand's qualifications. Schedule PMN-2-G contains the class embedded cost of service study summary results at the actual return using a test period ended September 30, 2024. Schedule PMN-3-G contains the class embedded cost of service study summary at existing, claimed (uniform) and proposed rate of return. Schedule PMN-4-G presents the complete detailed output of the test period class embedded cost of service study as summarized in Schedule PMN-2-G. Schedule PMN-5-G, pages 1 and 2 presents the Unbundled Costs Summary of Results of Schedule PMN-3-G by the major COS cost component categories based on the present revenue level test period ended September 30, 2024. Schedule PMN-5-G, pages 3 and 4 present the same information at the proposed equalized rate of return revenue levels using the future test period September 30, 2025. Schedule PMN-6-G provides a description of the allocation factors used in the embedded cost of service study (Schedule PMN-4-G). Exhibit G-7 includes the embedded cost of service summary of results at the proposed future test period ended September 30, 2025. Exhibit G-8 presents the gas rate design calculations for the proposed rates and associated revenue targets. Also included in Exhibit G-8 are the gas bill impacts at the present and proposed revenue target levels.

EMBEDDED COST OF SERVICE STUDY

Embedded Cost of Service Study

Q. Would you briefly define an Embedded Cost of Service Study?

A. The cost to serve the customers of any utility company generally consists of allowable investments, operating expenses, and a return. For a historical test period, these costs are on record, and the overall cost to serve the collective customers of the utility may be readily established. On the other hand, the unique cost to provide services and energy to customers of the various service classifications is much less apparent. Costs can vary significantly between customer classes depending upon the nature of their demands upon the system and the facilities required to serve them. The purpose of an Embedded Cost of Service Study is to directly assign costs based on the utility records or to allocate each relevant and identifiable component of cost on an appropriate basis in order to determine the proper cost to serve the utility's respective customer classes. These analyses result in matrices which display the detailed total costs of serving each customer class of service in the study. Additionally, these costs are further unbundled into more detailed cost component categories reflecting the various services provided by the Company to its customers for energy delivery.

Q. Please describe the procedure that you used in preparing your Embedded Cost of Service Study?

A. Through the application of a computerized microcomputer cost model developed by Management Applications Consulting specifically for Pike's gas operations, it was possible to treat each element of Rate Base, Revenue and Operating Expense in detail and to classify and directly assign or allocate each item to the customer classes. This distribution cost of service classified all costs as being demand-related or customer-related since there are no commodity-related costs in this study.

The demand-related costs are fixed costs created by the loads placed on the various components of the gas system. The customer-related costs are fixed costs created by the customers connected to the system regardless of their usage. The complete detailed line-by-line allocation process is presented in Schedule PMN-4-G for Pike's gas operations for the test period ended September 30, 2024. This schedule is the underlying support for all the cost of service results presented in Schedules PMN-2-G, PMN-3-G, and PMN-5-G.

Q. Please summarize your cost of service study.

A. Schedule PMN-3-G shows a summary of class revenue requirements at existing rates, at an overall uniform 8.59% targeted (claimed) rate of return identified by the Company, and at proposed revenue levels. A second analysis, Schedule PMN-5-G, summarizes the unbundled costs to serve each major cost component category at present rates and at an equalized target rate of return for each class of service to assist in the rate design process. The calculated monthly customer charge for each class of service is shown on at existing (page 2, line 24) and uniform (page 4, line 24) ROR schedules. The specific customer costs included in the total monthly customer costs are shown in detail on lines 24 through 30.

<u>Description of Cost of Service (COS) Model</u>

Q. How does the computerized cost of service model operate?

A. The cost of service model is essentially a cost matrix. The vertical dimension of the study consists of the costs to serve as provided by the Company. The development of the cost of service study begins with rate base and continues with revenues, operating expenses, taxes, and the computation of a labor allocator. The cost model includes three additional pieces, a summary of costs to serve, a list of the allocation factors employed in the study and a revenue requirements section. The horizontal portion consists of the assignment of all costs to each of the Company's customer classes.

Each page, starting with page 1 has an important column immediately preceding the numerical data marked "ALLOC", an abbreviation for ALLOCATOR. The ALLOC column contains an acronym to indicate the allocation factor used to allocate the costs shown in the Total Gas Company column to each customer class. A tabulation of these allocators in absolute form, typically total dollars or volumes and as a percent of total has been provided at the end of the study beginning on page 15 in Schedule PMN-4-G and is repeated in the same sequence as a percent of the total value for each allocator at the end of the study beginning on page 21.

Using these allocation factors, costs shown in the Total Company column that were not directly assigned were allocated to each customer class. The cost of service information provided in the "Total" vertical column is based on the testimony and exhibits for the test year provided by the Company.

Q. What customer classes did you recognize in your Cost of Service Study?

A. The cost of service study recognized and allocated the Company's cost to the rate classes as follows:

Rate Designation	Description
SC-1, 231	Residential Space Heating
SC-1, 631	Residential Domestic
SC-1, 531&731	Residential Other
SC-2, 162	General Service Commercial
SC-2, 331	Commercial Space Heating

Cost of Service Model Allocation Methodology

Q. Would you please tell us how you chose allocation factors for your cost study?

A. In the cost allocation process, we attempted to determine the intended use of specific plant investments and then examined the specific use of these assets in the test year. As part of the cost of service process, we then separately developed the required external allocators or selected internal allocators to assign the various costs appropriately to each customer class. A complete and detailed list of each allocation factor has been provided in Schedule PMN-4-G, pages 15 through 26. Pages 15 through 20 present the total actual Company values while the remaining pages 21 through 26 reformat and unitize these same values with each factor totaling to unity or one. A description of these allocation factors has been provided in Exhibit G-6, Schedule PMN-6-G.

<u>Rate Base Allocation</u>

Q. Please describe the allocation of rate base to customer classes.

A. Rate base allocation is shown on pages 3 through 5 of Schedule PMN-4-G. The gas supply is set to zero in this study. Distribution plant represents investment in facilities to deliver gas to the customer meter.

Q. Please describe the allocation of Distribution Mains Acct 376 to customer classes.

A. The Distribution Mains account has been classified as demand (46.97%) and customer (53.93%) related based on the results of the minimum-size study developed for use in the 2013 General Base Rate Increase Filing. The demand-related Distribution Mains as well as other demand-related Distribution plant was allocated to customer classes using the Design Day factors shown on page 15 of Schedule PMN-4-G. The customer-related portion of Distribution Mains was allocated on the number of customers by rate class.

Q. What are the other customer-related allocation factors included in your cost study?

A. Customer-related plant items were allocated using various **CUST**-prefixed allocators for services, meters, and other such customer-related items. A complete list of these factors has been provided on page 16 of the cost of service study.

Q. How was general plant allocated on page 3 of Schedule PMN-4-G?

A. General plant was allocated on an internally generated labor allocation factor (**LABOR**) based on labor expensed in the test. Each Operations and Maintenance account was examined to determine the labor portion of expense included. The labor portions of these costs were allocated separately in the same manner as the total Operations and Maintenance accounts were allocated. The development of this allocator is shown on Schedule PMN-4-G, pages 13 and 14.

Q. How was each account of depreciation reserves assigned?

A. The plant Depreciation Reserves by function and the distribution account detail were obtained from the Company's records and allocated to customer classes based on the allocation of the corresponding plant account.

Q. How was Construction Work in Progress assigned?

A. The Construction Work in Progress was allocated to customer classes based on total plant.

Q. What other elements of rate base were included in your study?

A. Each adjustment to rate base has been detailed on Schedule PMN-4-G, page 5. Additions to net plant included allowance for working capital which includes Cash Working Capital, Materials and Supplies, Prepayments, and Deferred Debits (net of taxes). The deductions from net plant include customer deposits, deferred credits (net of taxes), and deferred income taxes and credits.

Each adjustment to rate base was allocated on the most appropriate allocation factor. For example, allowance for working capital items materials and supplies and prepayments of property tax and insurance were allocated on **TOTPLT,** prepayments of PA PUC assessment were allocated on claimed revenues (**CLAIMREV)** and cash working capital was allocated on O&M expense excluding purchased gas (**OMXPP**).

<u>Operating Revenue Allocation</u>

Q. How were operating revenues assigned?

A. Operating revenues (Schedule PMN-4-G, page 6) are based on the Company's books and records by customer class allocated on the most appropriate allocation factor. Sales of Gas revenue were directly assigned to each class. Other operating revenue Account 487, late payment charges, was allocated on the basis of the late payment charges incurred for each rate class. Miscellaneous service revenues and other gas revenues were allocated on total plant (**TOTPLT**).

Operating Expense Allocation

Q. How were the Operation and Maintenance Expenses allocated?

A. Distribution O&M expenses follow the allocation of distribution plant. Customer Accounts, Sales Expenses, and Administrative and General Expenses were allocated using a variety of methods based on direct assignments, revenues, plant, and labor costs. Whenever possible, specific information detailing class cost responsibilities or weightings were utilized in order to develop the most accurate cost study possible. Customer Service and Sales Expenses used a composite allocation factor that was weighted 50% on customers and 50% on sales.

A&G expenses were primarily allocated on the **LABOR** allocator. The regulatory commission expense was allocated on the **CLAIMREV** allocator and the remaining A&G expenses were allocated on **TOTPLT**, and General plant in service (**GENLPLT**).

Q. What are the remaining operating expenses?

A. The remaining operating expenses consist of depreciation expenses, taxes other than income taxes, state income taxes and a detailed federal income tax calculation.

Q. How were they allocated?

A. Depreciation expenses were allocated on the basis of plant in service. Taxes Other Than Income Taxes were allocated using the **TOTPLT, LABOR,** and **CLAIMREV** allocation factors; PURTA taxes, capital stock, and real estate taxes were allocated on **TOTPLT.**

Payroll related taxes were allocated on the **LABOR** allocation factor and the PA and local use tax was allocated on the **CLAIMREV** allocation factor. Federal income taxes and state taxes were computed for each customer class based on the allocated expenses previously discussed.

<u>Cost of Service Study Results</u>

Q. Could you summarize the results of your cost study at present rates?

A. The results of the test year ended September 30, 2024 cost of service study show that the rates presently in effect generate somewhat different rates of return for each customer class. Schedules PMN-2-G and PMN-3-G show that the Company's current rates produce inequities between the customer classes as summarized in the following table:

Cost of Service Results – Present ROR

	Schedule PMN-2-G	
	ROR (%)	ROR Index
Total Company	4.29%	1.00
Residential Space Heating	3.40%	0.79
Residential Domestic	0.63%	0.15
Residential Other	3.76%	0.88
General Service Commercial	19.84%	4.63
Commercial Space Heating	8.56%	2.00

Q. Has Mr. Normand employed "tolerance bands" around the total system rate of return in developing class revenue responsibilities?

A. Yes. The proposed class revenue target responsibility has been measured with respect to a ±10% tolerance band around the total system average rate of return. Classes would not be considered "surplus" or "deficient" if the class COS rate of return falls within this band.

Q. Based on the application of a ±10% tolerance band around the calculated total system rate of return of 8.59%, which classes are considered to be deficient and which classes are surplus?

A. The customer class ROR inequities shown in Schedules PMN-2-G and PMN-3-G indicate that the Service Classification No. 2 General Service and Commercial customer classes are surplus and are subsidizing the Service Classification No.1 Residential customer classes which are deficient.

RATE DESIGN

Q. How did you approach the task of rate design in this case?

A. The class cost of service unbundled revenue requirement summary results at a proposed revenue levels presented in Exhibit G-6, Schedule PMN-5-G, pages 3 and 4 which use a future test period for the twelve months ended of September 30, 2025 provided the basis or starting point for all of the proposed rate designs presented in Exhibit G-8.

Q. Was there a logical progression in your efforts to perform the rate design?

A. Our rate design efforts were performed in three discrete steps. First, we determined the total costs incurred to serve each customer class using the September 30, 2025 future test year, Exhibit G-7. Next, we examined the embedded cost of service study at the

Company's uniform ROR (equalized annual increase) and compared these results to the revenues currently produced by each customer class, Exhibit G-6, Schedule PMN-3-G. Finally, we developed the proposed (moderated) class revenue targets and rate designs utilizing these results and adjusted present rate charges to all rates.

Q. Could you briefly list the factors that you considered in arriving at your proposed rate designs?

A. The proposed rate year rate design and class revenue targets considered several very important factors which I will list in the order that they were considered in my decision process:

1. Existing Rate Structure
2. Present Rate of Returns & Index of Returns (Schedules PMN-2-G and PMN-3-G)
3. Cost of Service at a Uniform Target Rate of Return (Exhibit G-7 and PMN-3-G)
4. Use of unbundled costs results presented in Schedule PMN-5-G
5. Initial Target Class Revenue Increases using Rate Year Revenue Requirement

Q. Have you prepared an unbundling cost study for Pike?

A. Yes, I have. Exhibit G-6, Schedule PMN-5-G provides for the detailed results by major cost categories that are presented in my testimony. The most important aspect of these unbundled results is with respect to the customer-related costs presented on Schedule PMN-5-G, pages 3 and 4, at a uniform ROR level for each customer class. These results indicate the proper level of customer-related costs that should be recovered on a monthly basis and was used as a guide in establishing the proposed rate designs presented in Exhibit G-8, pages 1 through 4. While it is important to recognize that the delivery only revenue requirements are essentially fixed and invariant to throughput, the overall goal representing customer impacts prevents establishing the total delivery revenue requirement as a monthly fixed cost for each customer and requiring a continued dependence on volumetric charges.

<u>Bill Impact Analysis</u>

Q. Have you prepared an analysis of the impact of your proposed rates?

A. Yes. This analysis is shown on pages 5 through 13 of Exhibit G-8. For each rate class, we have shown the total charges under present and proposed rates for a variety of usage levels for the Service Classification No. 1 (SC-1) and Service Classification No. 2 (SC-2) as shown on page 6 of Exhibit G-8. This page shows that the total monthly bill, including gas costs, for a SC-1 Residential Heating customer using 100 Ccf would increase from $167.72 to $242.73, or an 44.3% increase. The proposed rates reflect an overall increase of 44.2% increase for the SC-1 class and an overall 7.2% increase for the SC-2 class as shown on Exhibit G-8, page 12.

Q. Does this conclude your testimony?

A. Yes, it does. We reserve the right to update or amend this testimony.

Schedule PMN-1-G

Qualifications
of
Paul M. Normand

<u>Qualification of Paul M. Normand</u>

Q. Mr. Normand, what is your present position?

A. I am a principal in the consulting firm of Management Applications Consulting, Inc. (MAC). This Company provides consulting services to the utility industry in such fields as loss studies, econometric studies, cost analyses, rate design, expert testimony, and regulatory assistance. The Company is located in Reading, Pennsylvania.

Q. What is your educational background?

A. I graduated from Northeastern University in 1975, with a Bachelor of Science Degree and a Master of Science Degree in Electrical Engineering-Power System Analysis. I have attended various conferences and meetings concerning engineering and cost analysis.

Q. What is your professional background?

A. I was employed by the Massachusetts Electric Company in the Distribution Engineering Department while attending Northeastern University. My principal areas of assignment included new service, voltage conversions, and system planning. Upon graduation from Northeastern University, I joined Westinghouse Electric Corporation Nuclear Division in Pittsburgh, Pennsylvania. In that position, I assisted in the procurement and economic analysis of electrical/electronic control equipment for the nuclear reactor system.

In 1976, I joined Gilbert Associates as an Engineer providing consulting services in the rate and regulatory area to utility companies. I was promoted to Senior Engineer in 1977, Manager of the Austin office 1980, and Director of Rate Regulatory Service in 1981.

In June, 1983, I left Gilbert to form a separate consulting firm and I am now a principal and President of Management Applications Consulting, Inc. My principal areas of concentration have been in loss studies, economic analyses, and pricing.

Q. Have you testified in support of any cost studies that you participated in or performed?

A. Yes, I have testified about such studies before the following regulatory agencies: the Maine Public Utility Commission, the Public Utility Commission of Texas, Illinois Commerce Commission, New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, New York Public Service Commission, Pennsylvania Public Utility Commission, the Massachusetts Department of Public Utilities, the Kentucky Public Service Commission, the Arkansas Public Service Commission, the Public Service Commission of Louisiana, the Public Utilities Commission of Ohio, the Public Service Commission of Missouri, the Delaware Public Service Commission, the Maryland Public Service Commission, the Indiana Utility Regulatory Commission, the North Carolina Utilities Commission and the Federal Energy Regulatory Commission.

Q. Could you please briefly discuss your technical experience?

A. I have performed numerous embedded and marginal cost of service studies, time differentiated bundled and fully unbundled cost studies for both electric and gas utilities since 1980. I have also used such studies in the design and presentation of detailed rate proposals before regulatory agencies.

My additional experience has been in the area of unaccounted for loss evaluations for electric and gas utilities for over thirty years. These studies include a detailed review of each system and the calculation of appropriate recovery factors.

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
SUM	1	**SUMMARY AT PRESENT RATES**									
SUM	2										
SUM	3	**DEVELOPMENT OF RETURN**									
SUM	4										
SUM	5	**OPERATING REVENUE**									
SUM	6	Sales of Gas Revenue - Base	SCH REV, LN 4	1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
SUM	7	Other Operating Revenue	SCH REV, LN 12	3,850	2,939	911	2,880	40	19	475	436
SUM	8	TOTAL OPERATING REVENUE		1,090,185	896,006	194,179	865,999	26,410	3,597	83,354	110,825
SUM	9										
SUM	10	**OPERATING EXPENSES**									
SUM	11	Operation and Maintenance Expense	SCH EOM, LN 86	634,194	576,075	58,119	551,220	22,667	2,188	17,667	40,452
SUM	12	Depreciation and Amortization Expense	SCH EDA, LN 25	208,161	184,078	24,082	176,268	7,089	721	7,649	16,433
SUM	13	Taxes Other Than Income Taxes	SCH TXO, LN 10	24,691	22,308	2,383	21,327	894	87	728	1,655
SUM	14	State Income Taxes	SCH TXI, LN 26	(22,516)	(26,608)	4,093	(24,854)	(1,662)	(93)	3,236	857
SUM	15	Federal Income Taxes	SCH TXI, LN 39	(54,449)	(64,347)	9,897	(60,105)	(4,018)	(224)	7,826	2,072
SUM	16	TOTAL OPERATING EXPENSES		790,080	691,506	98,574	663,856	24,970	2,680	37,105	61,469
SUM	17										
SUM	18	Operating Income Before Taxes		223,139	113,545	109,595	117,184	(4,240)	601	57,311	52,284
SUM	19										
SUM	20	**OPERATING INCOME (RETURN)**		300,104	204,500	95,605	202,143	1,440	917	46,249	49,355
SUM	21										
SUM	22	**DEVELOPMENT OF RATE BASE**									
SUM	23	Gas Utility Plant in Service	SCH RBP, LN 41	7,620,197	6,685,423	934,774	6,411,190	247,922	26,311	306,122	628,653
SUM	24	Less: Utility Accumulated Depreciation	SCH RBD, LN 23	569,683	495,437	74,246	474,907	18,583	1,947	23,957	50,289
SUM	25	Plus: Rate Base Additions	SCH RBO, LN 12	268,300	234,731	33,569	225,171	8,636	925	11,038	22,530
SUM	26	Less: Rate Base Deductions	SCH RBO, LN 22	315,400	230,904	84,496	221,662	8,356	886	60,054	24,441
SUM	27	**TOTAL RATE BASE**	SCH RBO, LN 24	7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
SUM	28										
SUM	29	**RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**		4.29%	3.30%	11.81%	3.40%	0.63%	3.76%	19.84%	8.56%
SUM	30	**INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**		1.00	0.77	2.76	0.79	0.15	0.88	4.63	2.00
SUM	31										
SUM	32										
SUM	33										
SUM	34										
SUM	35										
SUM	36										
SUM	37										
SUM	38										
SUM	39										
SUM	40										
SUM	41										
SUM	42										
SUM	43										
SUM	44										
SUM	45										
SUM	46										
SUM	47										
SUM	48										
SUM	49										
SUM	50										

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**									
RRW	2										
RRW	3	PRESENT RATE OF RETURN (EXISTING RATES)									
RRW	4	---									
RRW	5	Rate Base		7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
RRW	6	Net Operating Income (Present Rates)		300,104	204,500	95,605	202,143	1,440	917	46,249	49,355
RRW	7	Rate of Return @ Present Rates		4.29%	3.30%	11.81%	3.40%	0.63%	3.76%	19.84%	8.56%
RRW	8	Relative Rate of Return		1.00	0.77	2.76	0.79	0.15	0.88	4.63	2.00
RRW	9	Sales Revenue at Present Rates		1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
RRW	10	Revenue Present Rates $/Ccf		$711.8354	$799.8246	$471.9309	$798.2741	$854.6320	$796.5648	$453.9848	$486.3658
RRW	11	Revenue Required - $/Month/Customer		$66,002.46	$57,784.98	$192,497.60	$58,445.23	$42,056.61	$59,637.37	$276,262.96	$156,802.13
RRW	12										
RRW	13										
RRW	14	CLAIMED RATE OF RETURN									
RRW	15	---									
RRW	16	Claimed Rate of Return		8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
RRW	17	Return Required for Claimed Rate of Return		917,310	809,432	107,878	776,197	30,048	3,187	32,525	75,353
RRW	18	Sales Revenue Required @ Claimed ROR		2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
RRW	19	Sales Revenue Deficiency		942,350	914,083	28,267	867,742	42,861	3,480	(14,767)	43,034
RRW	20	Percent Increase Required		86.75%	102.35%	14.63%	100.54%	162.54%	97.25%	-17.82%	38.98%
RRW	21	Annual Booked Throughput Sales (Ccf)		1,526,104	1,116,578	409,525	1,081,232	30,855	4,492	182,559	226,966
RRW	22	Sales Revenue Required $/Ccf		$1,329.3230	$1,618.4710	$540.9553	$1,600.8234	$2,243.7594	$1,571.2626	$373.0969	$675.9710
RRW	23	Sales Revenue Deficiency $/Ccf		$617.4877	$818.6464	$69.0244	$802.5493	$1,389.1274	$774.6978	($80.8879)	$189.6052
RRW	24										
RRW	25										
RRW	26	PROPOSED RATE OF RETURN									
RRW	27	---									
RRW	28	Rate Base at Future Test Year 09/30/2025		10,679,156	9,423,260	1,255,896	9,036,345	349,808	37,108	378,655	877,240
RRW	29	Proposed Base Gas Sales Revenues		2,028,685	1,781,499	247,186	1,723,140	51,209	7,150	106,165	141,021
RRW	30	Base Sales Revenue Deficiency		942,351	888,432	53,919	860,021	24,840	3,572	23,286	30,633
RRW	31	Return Required for Proposed Revenue		2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
RRW	32	Percent Increase Required at Proposed Rates		86.75%	99.48%	27.90%	99.64%	94.20%	99.81%	28.10%	27.75%
RRW	33	Proposed Rate of Return		19.00%	19.18%	17.64%	19.15%	19.79%	19.02%	17.99%	17.49%
RRW	34	Relative Rate of Return		1.00	1.01	0.93	1.01	1.04	1.00	0.95	0.92
RRW	35										
RRW	36										
RRW	37										
RRW	38										
RRW	39										
RRW	40										
RRW	41										
RRW	42										
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RRW	50										

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
SUM	1	**SUMMARY AT PRESENT RATES**									
SUM	2										
SUM	3	**DEVELOPMENT OF RETURN**									
SUM	4										
SUM	5	**OPERATING REVENUE**									
SUM	6	Sales of Gas Revenue - Base	SCH REV, LN 4	1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
SUM	7	Other Operating Revenue	SCH REV, LN 12	3,850	2,939	911	2,880	40	19	475	436
SUM	8	TOTAL OPERATING REVENUE		1,090,185	896,006	194,179	865,999	26,410	3,597	83,354	110,825
SUM	9										
SUM	10	**OPERATING EXPENSES**									
SUM	11	Operation and Maintenance Expense	SCH EOM, LN 86	634,194	576,075	58,119	551,220	22,667	2,188	17,667	40,452
SUM	12	Depreciation and Amortization Expense	SCH EDA, LN 25	208,161	184,078	24,082	176,268	7,089	721	7,649	16,433
SUM	13	Taxes Other Than Income Taxes	SCH TXO, LN 10	24,691	22,308	2,383	21,327	894	87	728	1,655
SUM	14	State Income Taxes	SCH TXI, LN 26	(22,516)	(26,608)	4,093	(24,854)	(1,662)	(93)	3,236	857
SUM	15	Federal Income Taxes	SCH TXI, LN 39	(54,449)	(64,347)	9,897	(60,105)	(4,018)	(224)	7,826	2,072
SUM	16	TOTAL OPERATING EXPENSES		790,080	691,506	98,574	663,856	24,970	2,680	37,105	61,469
SUM	17										
SUM	18	Operating Income Before Taxes		223,139	113,545	109,595	117,184	(4,240)	601	57,311	52,284
SUM	19										
SUM	20	**OPERATING INCOME (RETURN)**		300,104	204,500	95,605	202,143	1,440	917	46,249	49,355
SUM	21										
SUM	22	**DEVELOPMENT OF RATE BASE**									
SUM	23	Gas Utility Plant in Service	SCH RBP, LN 41	7,620,197	6,685,423	934,774	6,411,190	247,922	26,311	306,122	628,653
SUM	24	Less: Utility Accumulated Depreciation	SCH RBD, LN 23	569,683	495,437	74,246	474,907	18,583	1,947	23,957	50,289
SUM	25	Plus: Rate Base Additions	SCH RBO, LN 12	268,300	234,731	33,569	225,171	8,636	925	11,038	22,530
SUM	26	Less: Rate Base Deductions	SCH RBO, LN 22	315,400	230,904	84,496	221,662	8,356	886	60,054	24,441
SUM	27	**TOTAL RATE BASE**	SCH RBO, LN 24	7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
SUM	28										
SUM	29	**RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**		4.29%	3.30%	11.81%	3.40%	0.63%	3.76%	19.84%	8.56%
SUM	30	**INDEX RATE OF RETURN EXCL PURCHASED GAS (PRESENT)**		1.00	0.77	2.76	0.79	0.15	0.88	4.63	2.00
SUM	31										
SUM	32										
SUM	33										
SUM	34										
SUM	35										
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Pike County Light & Power Company
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12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
SUM	1	**HISTORICAL AND FUTURE YEAR DIFFERENCE ADJUSTMENTS:**									
SUM	2	**(For Future Test Year 12 Months Ended September 30 2025)**									
SUM	3										
SUM	4	**OPERATING INCOME (RETURN) @ PRESENT RATES**		300,104	204,500	95,605	202,143	1,440	917	46,249	49,355
SUM	5	**LESS Historical and Future Year Differences:**									
SUM	6	Retail Sales Revenue	CLAIMREV	35,857	31,941	3,916	30,593	1,224	125	1,204	2,712
SUM	7	487-Late Payment Charges	REV_487	(2,500)	(2,019)	(481)	(1,961)	(48)	(11)	(228)	(253)
SUM	8	**PLUS Historical and Future Year Differences:**									
SUM	9	O&M Expense - Labor Related	LABOR	58,700	53,277	5,423	50,910	2,160	208	1,632	3,790
SUM	10	O&M Expense - 904-Uncollectible Accounts	EXP_904	(8,200)	(8,200)	0	(8,200)	0	0	0	0
SUM	11	O&M Expense - 928-Regulatory Commission	CLAIMREV	9,400	8,374	1,026	8,020	321	33	316	711
SUM	12	Depreciation Expense	TOTPLT	124,900	109,578	15,322	105,084	4,064	431	5,018	10,304
SUM	13	TOIT - Base Payroll Taxes	LABOR	3,106	2,819	287	2,694	114	11	86	201
SUM	14	TOIT - PA Property Tax	TOTPLT	(103)	(90)	(13)	(86)	(3)	(0)	(4)	(8)
SUM	15	State Income Taxes	CLAIMREV	(33,515)	(29,581)	(3,935)	(28,329)	(1,132)	(119)	(1,190)	(2,745)
SUM	16	Federal Income Taxes	CLAIMREV	(81,050)	(71,534)	(9,516)	(68,509)	(2,738)	(288)	(2,878)	(6,638)
SUM	17	**OPERATING INCOME @ PRESENT RATES WITH DIFFERENCES**		260,224	169,779	90,445	169,192	(170)	756	44,246	46,199
SUM	18	Operating Income Before Taxes		68,693	(22,291)	90,985	(12,605)	(9,719)	32	51,239	39,745
SUM	19										
SUM	20	**RATE BASE**	SCH SUM, LN 27	7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
SUM	21	**Historical and Future Year Difference Adjustments:**									
SUM	22	Gas Utility Plant & Reserves Adjustments	TOTPLT	3,492,842	3,064,373	428,469	2,938,674	113,639	12,060	140,316	288,153
SUM	23	Additions:									
SUM	24	Cash Working Capital	OMXPP	143,400	129,952	13,448	124,200	5,245	506	4,088	9,360
SUM	25	Materials and Supplies	TOTPLT	5,800	5,089	711	4,880	189	20	233	478
SUM	26	Prepayments	TOTPLT	100	88	12	84	3	0	4	8
SUM	27	Deferred Debits (Net of Tax)	TOTPLT	18,200	15,967	2,233	15,312	592	63	731	1,501
SUM	28	Deductions:									
SUM	29	Customer Deposits	CUSTDEP	600	58	542	58	0	0	509	34
SUM	30	Deferred Income Taxes and Credits	TOTPLT	(16,000)	(14,037)	(1,963)	(13,461)	(521)	(55)	(643)	(1,320)
SUM	31	**RATE BASE WITH ADJUSTMENTS**		10,679,156	9,423,260	1,255,896	9,036,345	349,808	37,108	378,655	877,240
SUM	32										
SUM	33	**EQUALIZED RETURN AT PROPOSED ROR OF 8.59%**									
SUM	34	**DEVELOPMENT OF RETURN (RATE BASE * 8.59% ROR)**		917,310	809,432	107,878	776,197	30,048	3,187	32,525	75,353
SUM	35	Additional Return Required * Retention Factor 1.38%		906,521	882,470	24,051	837,428	41,688	3,354	(16,169)	40,220
SUM	36	487-Late Payment Charges	REV_487	2,500	2,019	481	1,961	48	11	228	253
SUM	37	**PLUS OPERATING EXPENSES**									
SUM	38	Operation and Maintenance Expense		696,594	631,545	65,049	603,911	25,195	2,439	19,842	45,206
SUM	39	Depreciation and Amortization Expense		333,061	293,657	39,404	281,352	11,152	1,153	12,666	26,738
SUM	40	Taxes Other Than Income Taxes		27,694	25,037	2,658	23,934	1,005	98	811	1,847
SUM	41	State Income Taxes		16,200	14,159	2,041	13,570	533	55	736	1,305
SUM	42	Federal Income Taxes		39,177	34,240	4,936	32,816	1,290	134	1,780	3,157
SUM	43	**TOTAL OPERATING EXPENSES**		1,112,725	998,638	114,087	955,583	39,176	3,879	35,834	78,253
SUM	44										
SUM	45	**EQUALS TOTAL COST OF SERVICE**		2,030,035	1,808,070	221,965	1,731,780	69,223	7,066	68,360	153,605
SUM	46										
SUM	47	**LESS: Other Operating Revenues**		1,350	920	430	919	(7)	8	248	183
SUM	48	**BASE RATE SALES @ EQUALIZED ROR 8.59%**		2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
SUM	49	**BASE RATE SALES REVENUE INCREASE**		942,350	914,083	28,267	867,742	42,861	3,480	(14,767)	43,034
SUM	50										

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
RBP	1	**DEVELOPMENT OF RATE BASE**									
RBP	2										
RBP	3	**GAS PLANT IN SERVICE**									
RBP	4	INTANGIBLE PLANT									
RBP	5	301-Organization	TOTPLT	0	0	0	0	0	0	0	0
RBP	6	303-Miscellaneous Intangible Plant	TOTPLT	0	0	0	0	0	0	0	0
RBP	7	TOTAL INTANGIBLE PLANT		0	0	0	0	0	0	0	0
RBP	8										
RBP	9	DISTRIBUTION PLANT									
RBP	10	374-Land & Land Rights	DDIST	744	581	163	564	15	2	58	105
RBP	11	375-Structures & Improvements	DDIST	0	0	0	0	0	0	0	0
RBP	12	376-Mains									
RBP	13	Demand	DDIST	1,831,770	1,430,792	400,978	1,387,518	37,499	5,776	142,503	258,475
RBP	14	Customer	CUSTDIST	2,521,960	2,367,692	154,267	2,262,174	96,263	9,256	46,280	107,987
RBP	15	Total Account 376		4,353,729	3,798,485	555,245	3,649,691	133,762	15,032	188,783	366,462
RBP	16	378-Measuring & Regulating Station Equip-Gen	DDIST	131,501	102,715	28,786	99,608	2,692	415	10,230	18,556
RBP	17	380-Services	CUSTSERV	1,693,812	1,529,392	164,419	1,461,446	61,986	5,960	49,524	114,895
RBP	18	381-Meters	CUSTMET	62,823	47,469	15,354	45,360	1,924	185	4,625	10,729
RBP	19	382-Meter Installations	CUSTMETIN	536,759	489,280	47,479	467,543	19,831	1,907	14,301	33,178
RBP	20	384-House Regulator Installations	CUSTREGULH	9,539	9,539	0	9,116	387	37	0	0
RBP	21	385-Industrial Meas. & Regulators	CUSTREGULI	36,151	0	36,151	0	0	0	10,889	25,262
RBP	22	TOTAL DISTRIBUTION PLANT		6,825,059	5,977,462	847,597	5,733,328	220,596	23,538	278,409	569,188
RBP	23										
RBP	24	GENERAL PLANT									
RBP	25	389-Land and Land Rights	LABOR	0	0	0	0	0	0	0	0
RBP	26	390-Structures and Improvements	LABOR	0	0	0	0	0	0	0	0
RBP	27	391-Office Furniture & Equipment	LABOR	0	0	0	0	0	0	0	0
RBP	28	393-Store Equipment	LABOR	0	0	0	0	0	0	0	0
RBP	29	394-Tools, Shop & Garage Equip.	LABOR	368,454	334,416	34,037	319,558	13,556	1,303	10,246	23,792
RBP	30	395-Laboratory Equipment	LABOR	0	0	0	0	0	0	0	0
RBP	31	397-Communication Equipment	LABOR	0	0	0	0	0	0	0	0
RBP	32	398-Miscellaneous Equipment	LABOR	0	0	0	0	0	0	0	0
RBP	33	399-Excess Reserve	LABOR	0	0	0	0	0	0	0	0
RBP	34	TOTAL GENERAL PLANT		368,454	334,416	34,037	319,558	13,556	1,303	10,246	23,792
RBP	35										
RBP	36	**TOTAL GAS PLANT IN SERVICE**		7,193,512	6,311,878	881,634	6,052,886	234,152	24,840	288,655	592,979
RBP	37										
RBP	38	COMMON PLANT IN SERVICE (Allocated)	LABOR	(26,357)	(23,922)	(2,435)	(22,859)	(970)	(93)	(733)	(1,702)
RBP	39	CWIP not taking interest	TOTPLT	453,042	397,467	55,575	381,163	14,740	1,564	18,200	37,375
RBP	40										
RBP	41	**TOTAL GAS UTILITY PLANT**		7,620,197	6,685,423	934,774	6,411,190	247,922	26,311	306,122	628,653
RBP	42										
RBP	43										
RBP	44										
RBP	45										
RBP	46										
RBP	47										
RBP	48										
RBP	49										
RBP	50										

Pike County Light & Power Company
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12 Months Ending September 30,2024

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		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
RBD	1	**LESS: ACCUMULATED DEPRECIATION**									
RBD	2										
RBD	3	INTANGIBLE PLANT ACCUM DEPRECIATION	INTPLT	0	0	0	0	0	0	0	0
RBD	4										
RBD	5	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION									
RBD	6	374-Land Rights	PLT_374	0	0	0	0	0	0	0	0
RBD	7	375-Structures & Improvements	PLT_375	0	0	0	0	0	0	0	0
RBD	8	376-Mains	PLT_376	249,602	217,769	31,833	209,239	7,669	862	10,823	21,009
RBD	9	378-Measuring & Regulating Station Equip-Gen	PLT_378	30,369	23,721	6,648	23,004	622	96	2,363	4,285
RBD	10	380-Services	PLT_380	119,902	108,263	11,639	103,453	4,388	422	3,506	8,133
RBD	11	381-Meters	PLT_381	13,215	9,986	3,230	9,542	405	39	973	2,257
RBD	12	382-Meter Installations	PLT_382	52,697	48,035	4,661	45,901	1,947	187	1,404	3,257
RBD	13	384-House Regulator Installations	PLT_384	1,662	1,662	0	1,589	67	6	0	0
RBD	14	385-Industrial Meas. &Regulators	PLT_385	7,482	0	7,482	0	0	0	2,254	5,228
RBD	15	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		474,930	409,437	65,492	392,728	15,097	1,612	21,322	44,171
RBD	16										
RBD	17	GENERAL PLANT ACCUMULATED DEPREC	GENLPLT	94,753	86,000	8,753	82,179	3,486	335	2,635	6,118
RBD	18										
RBD	19	**TOTAL ACCUMULATED DEPRECIATION OF GAS PLANT**		569,683	495,437	74,246	474,907	18,583	1,947	23,957	50,289
RBD	20										
RBD	21	COMMON PLANT ACCUM DEPRECIATION	COMPLT	0	0	0	0	0	0	0	0
RBD	22										
RBD	23	**TOTAL UTILITY PLANT RESERVES**		569,683	495,437	74,246	474,907	18,583	1,947	23,957	50,289
RBD	24										
RBD	25										
RBD	26	**NET GAS PLANT IN SERVICE**		7,050,514	6,189,986	860,529	5,936,282	229,339	24,364	282,165	578,363
RBD	27										
RBD	28										
RBD	29										
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		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
RBO	2										
RBO	3	**PLUS: ADDITIONS TO RATE BASE**									
RBO	4										
RBO	5	**WORKING CAPITAL**									
RBO	6	Cash Working Capital	OMXPP	(24,600)	(22,293)	(2,307)	(21,306)	(900)	(87)	(701)	(1,606)
RBO	7	Materials and Supplies	TOTPLT	271,000	237,756	33,244	228,004	8,817	936	10,887	22,357
RBO	8	Prepayments - PA PUC Assessment	CLAIMREV	4,053	3,610	443	3,458	138	14	136	307
RBO	9	Prepayments - Property Tax and Insurance	TOTPLT	1,347	1,182	165	1,133	44	5	54	111
RBO	10	Deferred Debits (Net of Tax)	TOTPLT	16,500	14,476	2,024	13,882	537	57	663	1,361
RBO	11	TOTAL WORKING CAPITAL		268,300	234,731	33,569	225,171	8,636	925	11,038	22,530
RBO	12	TOTAL ADDITIONS TO RATE BASE		268,300	234,731	33,569	225,171	8,636	925	11,038	22,530
RBO	13										
RBO	14										
RBO	15	**LESS: DEDUCTIONS TO RATE BASE**									
RBO	16	Customer Deposits	CUSTDEP	58,700	5,665	53,035	5,665	0	0	49,754	3,281
RBO	17	Deferred Credits (Net of Tax)	TOTPLT	1,600	1,404	196	1,346	52	6	64	132
RBO	18	Deferred Income Taxes and Credits									
RBO	19	Plant	DGPLT	255,100	223,835	31,265	214,651	8,304	881	10,236	21,029
RBO	20	Common Plant	COMPLT	0	0	0	0	0	0	0	0
RBO	21	Total Deferred Income Taxes and Credits		255,100	223,835	31,265	214,651	8,304	881	10,236	21,029
RBO	22	TOTAL DEDUCTIONS TO RATE BASE		315,400	230,904	84,496	221,662	8,356	886	60,054	24,441
RBO	23										
RBO	24	**TOTAL RATE BASE**		7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
RBO	25										
RBO	26										
RBO	27										
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Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
REV	1	**OPERATING REVENUES**									
REV	2										
REV	3	**SALES REVENUES**									
REV	4	Sales of Gas Revenues - Base		1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
REV	5	Sales Revenues - Purchased Gas-PGC	EGAS	0	0	0	0	0	0	0	0
REV	6	TOTAL SALES OF GAS		1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
REV	7										
REV	8	**OTHER OPERATING REVENUES**									
REV	9	487-Late Payments Charges	REV_487	6,301	5,089	1,212	4,942	120	27	574	638
REV	10	488-Miscellaneous Service Revenues	TOTPLT	0	0	0	0	0	0	0	0
REV	11	494-Other Gas Revenue (Adjustment)	TOTPLT	(2,451)	(2,760)	(301)	(2,062)	(80)	(8)	(98)	(202)
REV	12	TOTAL OTHER OPERATING REV		3,850	2,939	911	2,880	40	19	475	436
REV	13										
REV	14	**TOTAL OPERATING REVENUES**		1,090,185	896,006	194,179	865,999	26,410	3,597	83,354	110,825
REV	15										
REV	16										
REV	17										
REV	18										
REV	19										
REV	20										
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Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL GAS COMPANY (c)	Total Residential SC1 (a)	Total Commercial SC2 (e)	Residential Space Heating Rate 231 (f)	Residential Domestic Rate 631 (g)	Residential Other Rate 531 & 731 (h)	General Service Commercial Rate 162 (i)	Commercial Space Heating Rate 331 (j)
EOM	1	**OPERATION & MAINTENANCE EXPENSE**									
EOM	2	PRODUCTION EXPENSE									
EOM	3	Other Gas Supply Expense									
EOM	4	Operation									
EOM	5	804-Natural Gas Purchases-PGC	EGAS	0	0	0	0	0	0	0	0
EOM	6	805-Other Natural Gas Purchases	ETHRUPUT	0	0	0	0	0	0	0	0
EOM	7	807-Purchased Gas Expenses	ETHRUPUT	0	0	0	0	0	0	0	0
EOM	8	808.1 Gas withdrawn from storage—Debt.	ETHRUPUT	0	0	0	0	0	0	0	0
EOM	9	Total Other Gas Supply Expense		0	0	0	0	0	0	0	0
EOM	10	TOTAL PRODUCTION EXPENSE		0	0	0	0	0	0	0	0
EOM	11										
EOM	12	DISTRIBUTION EXPENSES									
EOM	13	Operation									
EOM	14	870-Operation Supervision and Engineering	LABORDM	5,755	5,196	559	4,965	211	20	168	390
EOM	15	874-Mains and Services Expenses	PLT_376380	0	0	0	0	0	0	0	0
EOM	16	875-Measuring & Reg. Station Exp.	PLT_378	0	0	0	0	0	0	0	0
EOM	17	878-Meter & House Regulator Expenses	PLT_3815	0	0	0	0	0	0	0	0
EOM	18	880-Other Expenses	DISTPLT	0	0	0	0	0	0	0	0
EOM	19	Total Distribution Operation		5,755	5,196	559	4,965	211	20	168	390
EOM	20	Maintenance									
EOM	21	887-Maintenance of Mains	PLT_376	5,277	4,604	673	4,423	162	18	229	444
EOM	22	889-Maint. of Measuring & Reg. Station Equip.-G	PLT_378	0	0	0	0	0	0	0	0
EOM	23	892-Maintenance of Services	PLT_380	220,921	199,476	21,445	190,614	8,085	777	6,459	14,986
EOM	24	893-Maint. of Meters & House Regulators	PLT_3815	0	0	0	0	0	0	0	0
EOM	25	894-Maintenance of Other Equipment	DISTPLT	0	0	0	0	0	0	0	0
EOM	26	Total Distribution Maintenance		226,198	204,080	22,118	195,038	8,247	796	6,688	15,430
EOM	27	TOTAL DISTRIBUTION PLANT O&M EXPENSES		231,953	209,276	22,677	200,003	8,458	816	6,856	15,820
EOM	28										
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
EOM	51	**OPERATION & MAINTENANCE EXPENSE**									
EOM	52										
EOM	53	CUSTOMER ACCOUNTS EXPENSES									
EOM	54	902-Meter Reading	CUSTMTRDG	2,982	2,801	181	2,676	114	11	55	127
EOM	55	903-Customer Records and Collection Exp	CUSTREC	36,158	33,952	2,206	32,443	1,377	132	659	1,547
EOM	56	904-Uncollectible Accounts	EXP_904	14,475	14,475	0	14,475	0	0	0	0
EOM	57	TOTAL CUSTOMER ACCTS EXPENSE		53,614	51,227	2,387	49,594	1,491	143	714	1,673
EOM	58										
EOM	59	CUSTOMER SERVICE & SALES EXPENSES									
EOM	60	908-Customer Assistance	CUSTASST	0	0	0	0	0	0	0	0
EOM	61	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0
EOM	62	910-Miscellaneous CS	CUSTCSM	0	0	0	0	0	0	0	0
EOM	63	911-Informational and Instructional Exp	CUSTSALES	1,298	1,082	215	1,040	38	4	90	125
EOM	64	917-Promotional Advertising Exp	CUSTSALES	5,398	4,503	895	4,328	157	18	375	520
EOM	65	TOTAL CUSTOMER SERVICE & SALES EXP		6,696	5,586	1,110	5,368	195	22	465	645
EOM	66										
EOM	67	TOTAL OPER & MAINT EXCL A&G		292,263	266,089	26,174	254,965	10,144	981	8,035	18,138
EOM	68										
EOM	69										
EOM	70	ADMINISTRATIVE & GENERAL EXPENSE									
EOM	71	920-Administrative Salaries	LABOR	147,467	133,844	13,623	127,897	5,425	521	4,101	9,522
EOM	72	921-Office Supplies & Expense	LABOR	50,927	46,222	4,705	44,168	1,874	180	1,416	3,288
EOM	73	922-Administrative Exp Transferred - Credit	LABOR	(46,694)	(42,381)	(4,314)	(40,498)	(1,718)	(165)	(1,298)	(3,015)
EOM	74	923-Outside Service Employed	LABOR	65,071	59,060	6,011	56,436	2,394	230	1,809	4,202
EOM	75	924-Property Insurance	TOTPLT	336	295	41	283	11	1	13	28
EOM	76	925-Injuries and Damages	LABOR	23,970	21,756	2,214	20,789	882	85	667	1,548
EOM	77	926-Employee Pensions & Benefits	LABOR	65,875	59,789	6,085	57,133	2,424	233	1,832	4,254
EOM	78	928-Regulatory Commission	CLAIMREV	20,677	18,419	2,258	17,641	706	72	694	1,564
EOM	79	930.2-Miscellaneous General	LABOR	3,268	2,966	302	2,834	120	12	91	211
EOM	80	930.6-Miscellaneous General - Vehicles	GENLPLT	5,100	4,629	471	4,423	188	18	142	329
EOM	81	932-Maintenance of General Plant	GENLPLT	5,936	5,388	548	5,148	218	21	165	383
EOM	82	TOTAL A&G EXPENSE		341,931	309,986	31,945	296,255	12,523	1,208	9,632	22,314
EOM	83										
EOM	84	**TOTAL OPERATION & MAINTENANCE EXPENSES**		634,194	576,075	58,119	551,220	22,667	2,188	17,667	40,452
EOM	85										
EOM	86	**TOTAL O&M EXPENSES**		634,194	576,075	58,119	551,220	22,667	2,188	17,667	40,452
EOM	87										
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
EDA	1	**DEPRECIATION & AMORTIZATION EXPENSE**									
EDA	2										
EDA	3	INTANGIBLE PLANT EXPENSE	INTPLT	0	0	0	0	0	0	0	0
EDA	4										
EDA	5	DISTRIBUTION PLANT EXPENSE									
EDA	6	374-Land Rights	PLT_374	0	0	0	0	0	0	0	0
EDA	7	375-Structures & Improvements	PLT_375	0	0	0	0	0	0	0	0
EDA	8	376-Mains	PLT_376	54,300	47,375	6,925	45,519	1,668	187	2,354	4,571
EDA	9	378-Measuring & Regulating Station Equip-Gen	PLT_378	6,621	5,172	1,449	5,015	136	21	515	934
EDA	10	380-Services	PLT_380	17,878	16,142	1,735	15,425	654	63	523	1,213
EDA	11	381-Meters	PLT_381	3,737	2,824	913	2,698	114	11	275	638
EDA	12	382-Meter Installations	PLT_382	14,361	13,091	1,270	12,509	531	51	383	888
EDA	13	384-House Regulators	PLT_385	212	0	212	0	0	0	64	148
EDA	14	385-Industrial Meas. & Regulators	PLT_385	940	0	940	0	0	0	283	657
EDA	15	387-Other Equipment	PLT_378387	0	0	0	0	0	0	0	0
EDA	16	388-Asset Retirement Costs for Distribution Plant	PLT_388	0	0	0	0	0	0	0	0
EDA	17	TOTAL DISTRIBUTION PLANT EXPENSE		98,048	84,603	13,445	81,167	3,103	333	4,397	9,048
EDA	18										
EDA	19	GENERAL PLANT DEPRE & AMORT EXPENSE	GENLPLT	48,908	44,390	4,518	42,418	1,799	173	1,360	3,158
EDA	20										
EDA	21	COMMON PLANT DEPRE & AMORT EXPENSE	COMPLT	45,853	41,617	4,236	39,768	1,687	162	1,275	2,961
EDA	22										
EDA	23	Amoritzation of Unallocated Depreciation Res	TOTPLT	15,351	13,468	1,883	12,915	499	53	617	1,266
EDA	24										
EDA	25	**TOTAL DEPRECIATION & AMORTIZATION EXPENSE**		208,161	184,078	24,082	176,268	7,089	721	7,649	16,433
EDA	26										
EDA	27										
EDA	28										
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		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
TXO	1	**OTHER OPERATING EXPENSES**									
TXO	2										
TXO	3	**TAXES OTHER THAN INCOME TAXES**									
TXO	4	**General Taxes**									
TXO	5	PURTA Taxes	TOTPLT	0	0	0	0	0	0	0	0
TXO	6	Capital Stock	TOTPLT	0	0	0	0	0	0	0	0
TXO	7	Payroll Related	LABOR	21,299	19,331	1,968	18,473	784	75	592	1,375
TXO	8	Property Tax	DGPLT	3,392	2,977	416	2,854	110	12	136	280
TXO	9	PA and Local Use Tax	CLAIMREV	0	0	0	0	0	0	0	0
TXO	10	Total General Taxes		24,691	22,308	2,383	21,327	894	87	728	1,655
TXO	11										
TXO	12										
TXO	13	**Franchise and Revenue Taxes**	CLAIMREV	0	0	0	0	0	0	0	0
TXO	14										
TXO	15	**TOTAL TAXES OTHER THAN INCOME**		24,691	22,308	2,383	21,327	894	87	728	1,655
TXO	16										
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
TXI	1	**DEVELOPMENT OF INCOME TAXES**									
TXI	2										
TXI	3	TOTAL OPERATING REVENUES		1,090,185	896,006	194,179	865,999	26,410	3,597	83,354	110,825
TXI	4	LESS:									
TXI	5	OPERATION & MAINTENANCE EXPENSE	SCH EOM, LN 86	634,194	576,075	58,119	551,220	22,667	2,188	17,667	40,452
TXI	6	DEPRECIATION & AMORTIZATION EXPENSE	SCH EDA, LN 25	208,161	184,078	24,082	176,268	7,089	721	7,649	16,433
TXI	7	TAXES OTHER THAN INCOME TAXES	SCH TXO, LN 15	24,691	22,308	2,383	21,327	894	87	728	1,655
TXI	8	NET OPERATING INCOME BEFORE TAXES		223,139	113,545	109,595	117,184	(4,240)	601	57,311	52,284
TXI	9	LESS:									
TXI	10	Interest Expense (incl amort of debt exp)	RATEBASE	504,938	446,567	58,371	428,252	16,555	1,759	16,810	41,562
TXI	11										
TXI	12	**BASE TAXABLE DISTRIBUTION INCOME**		(281,799)	(333,022)	51,223	(311,068)	(20,795)	(1,159)	40,501	10,722
TXI	13										
TXI	14										
TXI	15	**CALCULATION OF PA STATE INCOME TAXES**									
TXI	16	BASE STATE TAXABLE INCOME (pretax)	SCH TXI, LN 12	(281,799)	(333,022)	51,223	(311,068)	(20,795)	(1,159)	40,501	10,722
TXI	17	PLUS:									
TXI	18	Book Depreciation	TOTPLT	47,085	41,309	5,776	39,614	1,532	163	1,892	3,884
TXI	19	LESS:									
TXI	20	State Tax Depreciation (Over) Under Book	TOTPLT	(201,513)	(176,793)	(24,720)	(169,541)	(6,556)	(696)	(8,095)	(16,624)
TXI	21	PA BASE STATE TAXABLE INCOME		(127,371)	(197,538)	70,167	(181,141)	(15,771)	(626)	46,705	23,463
TXI	22	**PA STATE INCOME TAXES @ Tax Rate 7.99%**		(10,177)	(15,783)	5,606	(14,473)	(1,260)	(50)	3,732	1,875
TXI	23	PLUS:									
TXI	24	Deferred Income Tax Dr.- Account 410	TOTPLT	18,569	16,291	2,278	15,622	604	64	746	1,532
TXI	25	Deferred Income Tax Cr.- Account 411	TOTPLT	(30,907)	(27,116)	(3,791)	(26,004)	(1,006)	(107)	(1,242)	(2,550)
TXI	26	**TOTAL STATE INCOME TAX EXPENSE**		(22,516)	(26,608)	4,093	(24,854)	(1,662)	(93)	3,236	857
TXI	27										
TXI	28										
TXI	29	**CALCULATION OF FEDERAL INCOME TAXES**									
TXI	30	PA BASE TAXABLE INCOME	SCH TXI, LN 16	(281,799)	(333,022)	51,223	(311,068)	(20,795)	(1,159)	40,501	10,722
TXI	31	LESS:									
TXI	32	PA State Income Taxes	SCH TXI, LN 26	(22,516)	(26,608)	4,093	(24,854)	(1,662)	(93)	3,236	857
TXI	33	Other Federal Tax Adjustments	TOTPLT	(154,428)	(135,484)	(18,944)	(129,927)	(5,024)	(533)	(6,204)	(12,740)
TXI	34	FEDERAL ADJUSTED TAXABLE INCOME		(104,855)	(170,929)	66,074	(156,287)	(14,109)	(533)	43,469	22,606
TXI	35	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		(22,020)	(35,895)	13,876	(32,820)	(2,963)	(112)	9,128	4,747
TXI	36	PLUS:									
TXI	37	Deferred Income Tax Dr.- Account 410	TOTPLT	48,803	42,817	5,987	41,060	1,588	169	1,961	4,026
TXI	38	Deferred Income Tax Cr.- Account 411	TOTPLT	(81,233)	(71,268)	(9,965)	(68,345)	(2,643)	(280)	(3,263)	(6,702)
TXI	39	**TOTAL FEDERAL INCOME TAX EXPENSE**		(54,449)	(64,347)	9,897	(60,105)	(4,018)	(224)	7,826	2,072
TXI	40										
TXI	41										
TXI	42	**TOTAL PA INCOME TAX EXPENSE**		(22,516)	(26,608)	4,093	(24,854)	(1,662)	(93)	3,236	857
TXI	43	**TOTAL FEDERAL INCOME TAX EXPENSE**		(54,449)	(64,347)	9,897	(60,105)	(4,018)	(224)	7,826	2,072
TXI	44	**TOTAL INCOME TAX EXPENSE**		(76,965)	(90,955)	13,990	(84,959)	(5,680)	(317)	11,062	2,929
TXI	45										
TXI	46	**TOTAL OPERATING EXPENSES**		790,080	691,506	98,574	663,856	24,970	2,680	37,105	61,469
TXI	47										
TXI	48										
TXI	49										
TXI	50										

Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
TXI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**									
TXI	52										
TXI	53										
TXI	54										
TXI	55	**TAX RATES & FACTORS**									
TXI	56	GROSS RECEIPTS TAX RATE	0.00000								
TXI	57	STATE TAX RATE	0.07990								
TXI	58	EFFECTIVE STATE TAX RATE	0.09841								
TXI	59	FEDERAL TAX RATE - CURRENT	0.21000								
TXI	60	1 - EFFECTIVE TAX RATE	0.00000								
TXI	61	EFFECTIVE TAX RATE	0.27312								
TXI	62	EFFECTIVE FEDERAL RATE	0.18610								
TXI	63	RETENTION FACTOR	1.37961								
TXI	64	UNCOLLECTIBLES EXPENSE FACTOR	0.28000								
TXI	65										
TXI	66										
TXI	67										
TXI	68	**State Tax Income Adjustment**									
TXI	69	**(For Future Test Year 12 Months Ended September 30 2025)**									
TXI	70	Operating Income Before Income Taxes		(154,446)	(135,836)	(18,610)	(129,789)	(5,479)	(568)	(6,071)	(12,539)
TXI	71	Less Interest Expense (incl amort of debt exp)	RATEBASE	265,021	234,384	30,637	224,772	8,689	923	8,823	21,814
TXI	72	Pretax Income		(419,467)	(370,220)	(49,247)	(354,561)	(14,168)	(1,492)	(14,894)	(34,353)
TXI	73	**Add: Additional Taxable Income and Unallowable Deductions**									
TXI	74	Book Depreciation		124,900	109,578	15,322	105,084	4,064	431	5,018	10,304
TXI	75	Amortization of Rate Case Expenditures		9,400	8,374	1,026	8,020	321	33	316	711
TXI	76	Total		134,300	117,952	(32,899)	113,104	4,384	464	5,333	11,015
TXI	77	**Deduct: Non-Taxable Income and Allowable Deductions**									
TXI	78	Rate Case Expenditures		37,600	33,494	(16,551)	32,080	1,283	131	1,262	2,844
TXI	79	**State Taxable Income**		(322,767)	(285,762)	(16,551)	(273,537)	(11,067)	(1,159)	(10,824)	(26,181)
TXI	80	Current Tax Provision - State Taxable Income 7.99%		(25,789)	(22,832)	(16,551)	(21,856)	(884)	(93)	(865)	(2,092)
TXI	81	Deferred Income Tax Dr.- Account 410		3,004	2,676	328	2,563	103	10	101	227
TXI	82	Deferred Income Tax Cr.- Account 411		(10,731)	(9,424)	(1,306)	(9,037)	(350)	(37)	(426)	(880)
TXI	83	**Total State Income Taxes**		(33,515)	(29,581)	(17,529)	(28,329)	(1,132)	(119)	(1,190)	(2,745)
TXI	84										
TXI	85	**Federal Tax Income Adjustment**									
TXI	86	**(For Future Test Year 12 Months Ended September 30 2025)**									
TXI	87	State Taxable Income		(322,767)	(285,762)	(37,005)	(273,537)	(11,067)	(1,159)	(10,824)	(26,181)
TXI	88	Less State Income Taxes		33,515	29,581	(37,005)	28,329	1,132	119	1,190	2,745
TXI	89	Adjusted Taxable Income		(289,252)	(256,182)	(74,010)	(245,208)	(9,935)	(1,039)	(9,633)	(23,437)
TXI	90	**Total Federal Income Taxes @ Tax Rate 21.00%**		(60,743)	(53,798)	(148,019)	(51,494)	(2,086)	(218)	(2,023)	(4,922)
TXI	91	Deferred Income Tax Dr.- Account 410		7,896	7,034	862	6,737	269	27	265	597
TXI	92	Deferred Income Tax Cr.- Account 411		(28,203)	(24,770)	(3,433)	(23,752)	(921)	(97)	(1,120)	(2,313)
TXI	93	**Total Federal Income Taxes**		(81,050)	(71,534)	(2,571)	(68,509)	(2,738)	(288)	(2,878)	(6,638)
TXI	94										
TXI	95										
TXI	96										
TXI	97										
TXI	98										
TXI	99										
TXI	100										

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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
LAB	1	**DEVELOPMENT OF LABOR ALLOCATION FACTOR**									
LAB	2										
LAB	3	**PRODUCTION LABOR EXPENSE**									
LAB	4	Other Gas Supply Expense									
LAB	5	Operation - Accounts 804-808	OX_PRODO	0	0	0	0	0	0	0	0
LAB	6	Total Other Gas Supply		0	0	0	0	0	0	0	0
LAB	7	TOTAL PRODUCTION LABOR EXP		0	0	0	0	0	0	0	0
LAB	8										
LAB	9	**DISTRIBUTION LABOR EXPENSE**									
LAB	10	Operation									
LAB	11	874-Mains and Services Expenses	OX_874	0	0	0	0	0	0	0	0
LAB	12	875-Measuring & Reg. Station Exp.	OX_875	0	0	0	0	0	0	0	0
LAB	13	878-Meter & House Regulator Expenses	OX_878	0	0	0	0	0	0	0	0
LAB	14	880-Other Expenses	OX_880	0	0	0	0	0	0	0	0
LAB	15	Total Operation		0	0	0	0	0	0	0	0
LAB	16	Maintenance									
LAB	17	887-Maintenance of Mains	MX_887	0	0	0	0	0	0	0	0
LAB	18	889-Maint. of Measuring & Reg. Station Equip.	MX_889	0	0	0	0	0	0	0	0
LAB	19	892-Maintenance of Services	MX_892	229,258	207,004	22,254	197,807	8,390	807	6,703	15,551
LAB	20	893-Maint. of Meters & House Regulators	MX_893	0	0	0	0	0	0	0	0
LAB	21	894-Maintenance of Other Equipment	MX_894	0	0	0	0	0	0	0	0
LAB	22	Total Distribution Maintenance		229,258	207,004	22,254	197,807	8,390	807	6,703	15,551
LAB	23	TOTAL DISTRIBUTION LABOR EXP		229,258	207,004	22,254	197,807	8,390	807	6,703	15,551
LAB	24										
LAB	25	TOTAL OPER & MAINT LABOR EXP (PROD & DIST)		229,258	207,004	22,254	197,807	8,390	807	6,703	15,551
LAB	26										
LAB	27										
LAB	28										
LAB	29										
LAB	30										
LAB	31										
LAB	32										
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Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
LAB	51	**DEVELOPMENT OF LABOR ALLOCATION FACTOR CONTINUED**									
LAB	52										
LAB	53	CUSTOMER ACCOUNTS EXPENSES									
LAB	54	902-Meter Reading	CUSTMTRDG	2,495	2,344	152	2,239	95	9	46	106
LAB	55	903-Customer Records and Collection Expense	CUSTREC	31,765	29,828	1,938	28,502	1,210	116	579	1,359
LAB	56	904-Uncollectible Accounts	EXP_904	0	0	0	0	0	0	0	0
LAB	57	TOTAL CUSTOMER ACCTS LABOR EXPENSE		34,261	32,171	2,089	30,741	1,305	125	625	1,465
LAB	58										
LAB	59	CUSTOMER SERVICE & SALES EXPENSES									
LAB	60	908-Customer Assistance	CUSTASST	0	0	0	0	0	0	0	0
LAB	61	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0
LAB	62	910-Miscellaneous CS	CUSTCSM	0	0	0	0	0	0	0	0
LAB	63	912-Demonstrating and Selling Expenses	CUSTSALES	0	0	0	0	0	0	0	0
LAB	64	916 Miscellaneous Sales Expenses	CUSTSALES	0	0	0	0	0	0	0	0
LAB	65	TOTAL CUST SERVICE & SALES LABOR EXP		0	0	0	0	0	0	0	0
LAB	66										
LAB	67	TOTAL OPER & MAINT LABOR EXP EXCL A&G		263,519	239,175	24,344	228,549	9,695	932	7,328	17,016
LAB	68										
LAB	69	ADMINISTRATIVE & GENERAL EXPENSE									
LAB	70	920-Administrative Salaries	LABORXAG	10,748	9,755	993	9,322	395	38	299	694
LAB	71	921-Office Supplies & Expense	LABORXAG	0	0	0	0	0	0	0	0
LAB	72	923-Outside Service Employed	LABORXAG	0	0	0	0	0	0	0	0
LAB	73	924-Property Insurance	TOTPLT	0	0	0	0	0	0	0	0
LAB	74	925-Injuries and Damages	LABORXAG	0	0	0	0	0	0	0	0
LAB	75	926-Employee Pensions & Benefits	LABORXAG	0	0	0	0	0	0	0	0
LAB	76	928-Regulatory Commission	CLAIMREV	0	0	0	0	0	0	0	0
LAB	77	930.2-Miscellaneous General	LABORXAG	0	0	0	0	0	0	0	0
LAB	78	935-Maintenance of General Plant	GENLPLT	0	0	0	0	0	0	0	0
LAB	79	TOTAL A&G LABOR EXPENSE		10,748	9,755	993	9,322	395	38	299	694
LAB	80										
LAB	81	**TOTAL OPER & MAINTENANCE LABOR EXP**		274,267	248,930	25,336	237,870	10,090	970	7,627	17,710
LAB	82										
LAB	83										
LAB	84										
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Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AF	1	**ALLOCATION FACTOR TABLE**									
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	3										
AF	4	**CAPACITY**									
AF	5										
AF	6										
AF	7										
AF	8										
AF	9										
AF	10										
AF	11	CAPACITY - DISTRIBUTION RELATED (Design Day)									
AF	12	Capacity Distribution	DDIST	16,281	12,717	3,564	12,333	333	51	1,267	2,297
AF	13										
AF	14										
AF	15										
AF	16										
AF	17										
AF	18										
AF	19										
AF	20	**COMMODITY**									
AF	21	Annual Gas Cost (PGC)	EGAS	0	0	0	0	0	0	0	0
AF	22										
AF	23	Annual Gas Deliveries - Thruput (CCF)	ETHRUPUT	1,509,018	1,100,928	408,090	1,066,077	30,422	4,429	181,919	226,171
AF	24										
AF	25										
AF	26										
AF	27										
AF	28										
AF	29										
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	53										
AF	54	**CUSTOMER**									
AF	55	Distribution Mains	CUSTDIST	16,348	15,348	1,000	14,664	624	60	300	700
AF	56										
AF	57	Service Investment	CUSTSERV	1,693,812	1,529,392	164,419	1,461,446	61,986	5,960	49,524	114,895
AF	58	Meter Investment	CUSTMET	62,823	47,469	15,354	45,360	1,924	185	4,625	10,729
AF	59	Meter Installations	CUSTMETIN	536,759	489,280	47,479	467,543	19,831	1,907	14,301	33,178
AF	60	Regulators Investment	CUSTREGUL	9,539	8,960	580	8,562	363	35	175	405
AF	61	Regulators Investment - House	CUSTREGULH	8,960	8,960	0	8,562	363	35	0	0
AF	62	Regulators Investment - Industrial	CUSTREGULI	580	0	580	0	0	0	175	405
AF	63	Customer Deposits	CUSTDEP	381	37	344	37	0	0	323	21
AF	64										
AF	65										
AF	66										
AF	67	902-Meter Reading Expense	CUSTMTRDG	1,366	1,283	83	1,226	52	5	25	58
AF	68	903-Customer Records and Collections	CUSTREC	16,459	15,455	1,004	14,768	627	60	300	704
AF	69										
AF	70	908-Customer Assistance	CUSTASST	1.0000	0.8342	0.1658	0.8017	0.0292	0.0033	0.0695	0.0963
AF	71	909-Informational and Instructional Advertising	CUSTADVT	1.0000	0.8342	0.1658	0.8017	0.0292	0.0033	0.0695	0.0963
AF	72	910-Miscellaneous Customer Service	CUSTCSM	1.0000	0.8342	0.1658	0.8017	0.0292	0.0033	0.0695	0.0963
AF	73	916-Miscellaneous Sales Expense	CUSTSALES	1.0000	0.8342	0.1658	0.8017	0.0292	0.0033	0.0695	0.0963
AF	74										
AF	75	Number of Bills	CUSTBILLS	16,459	15,455	1,004	14,768	627	60	300	704
AF	76	Number of Customers (Average Annual)	CUST	16,348	15,348	1,000	14,664	624	60	300	700
AF	77										
AF	78										
AF	79										
AF	80										
AF	81										
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	103	**Plant Related**									
AF	104	Intangible Plant	INTPLT	0	0	0	0	0	0	0	0
AF	105	Distribution Plant in Service	DISTPLT	6,825,059	5,977,462	847,597	5,733,328	220,596	23,538	278,409	569,188
AF	106	Distribution Plant in Service - Capacity Related	DDISTPLT	2,653,460	2,470,408	183,053	2,361,782	98,955	9,671	56,510	126,543
AF	107	General Plant in Service	GENLPLT	368,454	334,416	34,037	319,558	13,556	1,303	10,246	23,792
AF	108	Common Plant in Service	COMPLT	(26,357)	(23,922)	(2,435)	(22,859)	(970)	(93)	(733)	(1,702)
AF	109	Total Gas Utility Plant In Service	TOTPLT	7,620,197	6,685,423	934,774	6,411,190	247,922	26,311	306,122	628,653
AF	110	Distribution Plant Excl Asset Retirement	DISTPLTXAR	6,825,059	5,977,462	847,597	5,733,328	220,596	23,538	278,409	569,188
AF	111	Total Distribution and General Plant	DGPLT	7,193,512	6,311,878	881,634	6,052,886	234,152	24,840	288,655	592,979
AF	112	Rate Base	RATEBASE	7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
AF	113										
AF	114	Account 374 - Land & Land Rights	PLT_374	744	581	163	564	15	2	58	105
AF	115	Account 375 - Structures & Improvements	PLT_375	0	0	0	0	0	0	0	0
AF	116	Account 376 - Mains	PLT_376	4,353,729	3,798,485	555,245	3,649,691	133,762	15,032	188,783	366,462
AF	117	Account 378 - Meas & Reg Station Equip-General	PLT_378	131,501	102,715	28,786	99,608	2,692	415	10,230	18,556
AF	118	Account 380 - Services	PLT_380	1,693,812	1,529,392	164,419	1,461,446	61,986	5,960	49,524	114,895
AF	119	Account 381 - Meters	PLT_381	62,823	47,469	15,354	45,360	1,924	185	4,625	10,729
AF	120	Account 382 - Meter Installations	PLT_382	536,759	489,280	47,479	467,543	19,831	1,907	14,301	33,178
AF	121	Account 384-House Regulator Installations	PLT_384	9,539	9,539	0	9,116	387	37	0	0
AF	122	Account 385-Industrial Regulators	PLT_385	36,151	0	36,151	0	0	0	10,889	25,262
AF	123	Account 387 - Other Equipment	PLT_387	9,539	9,539	0	9,116	387	37	0	0
AF	124	Account 388-Asset Retirement Costs for Distributior	PLT_388	36,151	0	36,151	0	0	0	10,889	25,262
AF	125	Accounts 376 & 378 - Mains & M&R	PLT_376379	4,485,230	3,901,200	584,031	3,749,300	136,454	15,446	199,013	385,018
AF	126	Accounts 376 & 380 - Mains & Services	PLT_376380	6,047,541	5,327,877	719,664	5,111,137	195,748	20,992	238,307	481,357
AF	127	Accounts 380 & 381 - Services & Meters	PLT_380381	1,693,812	1,529,392	164,419	1,461,446	61,986	5,960	49,524	114,895
AF	128	Accounts 381 through 385	PLT_3815	645,272	546,288	98,984	522,018	22,141	2,129	29,814	69,170
AF	129	Accounts 378 & 387	PLT_378387	141,040	112,255	28,786	108,724	3,079	452	10,230	18,556
AF	130										
AF	131	Distribution Plant in Service - Capacity Related									
AF	132	Residential Space Heating	DPLTRESSH	2,361,782	2,361,782	0	2,361,782	0	0	0	0
AF	133	Residential Domestic	DPLTRESD	98,955	98,955	0	0	98,955	0	0	0
AF	134	Residential Other	DPLTRESO	9,671	9,671	0	0	0	9,671	0	0
AF	135	General Service Commercial	DPLTGSC	56,510	0	56,510	0	0	0	56,510	0
AF	136	Commercial Space Heating	DPLTCSH	126,543	0	126,543	0	0	0	0	126,543
AF	137										
AF	138										
AF	139										
AF	140										
AF	141										
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AF	150										

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SCH	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL GAS COMPANY (c)	Total Residential SC1 (a)	Total Commercial SC2 (e)	Residential Space Heating Rate 231 (f)	Residential Domestic Rate 631 (g)	Residential Other Rate 531 & 731 (h)	General Service Commercial Rate 162 (i)	Commercial Space Heating Rate 331 (j)
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	153										
AF	154	**Production Expense Related**									
AF	155	Other Production Operation Expense	OX_PRODO	0	0	0	0	0	0	0	0
AF	156										
AF	157										
AF	158										
AF	159										
AF	160										
AF	161										
AF	162										
AF	163	**Distribution Expense Related**									
AF	164	Account 874 - Mains & Services Exp	OX_874	0	0	0	0	0	0	0	0
AF	165	Account 875 - Meas & Reg Station Exp - Gen	OX_875	0	0	0	0	0	0	0	0
AF	166	Account 878-Meter & House Regulator Expenses	OX_878	0	0	0	0	0	0	0	0
AF	167	Account 880 - Other Dist Oper Exp	OX_880	0	0	0	0	0	0	0	0
AF	168	Account 887 - Maint of Mains Exp	MX_887	5,277	4,604	673	4,423	162	18	229	444
AF	169	Account 889 - Maint of Meas & Reg Station Exp - G	MX_889	0	0	0	0	0	0	0	0
AF	170	Account 892 - Maint of Services Exp	MX_892	220,921	199,476	21,445	190,614	8,085	777	6,459	14,986
AF	171	Account 893 - Maint of Meter & House Reg Exp	MX_893	0	0	0	0	0	0	0	0
AF	172	Account 894 - Maint of Other Equipment Exp	MX_894	0	0	0	0	0	0	0	0
AF	173	O&M Accounts 874-880	OX_DIST	0	0	0	0	0	0	0	0
AF	174	O&M Accounts 887-894	MX_DIST	220,921	199,476	21,445	190,614	8,085	777	6,459	14,986
AF	175										
AF	176										
AF	177	**Customer Distribution Expense Related**									
AF	178	Account 902	OX_902	2,982	2,801	181	2,676	114	11	55	127
AF	179	Account 903	OX_903	36,158	33,952	2,206	32,443	1,377	132	659	1,547
AF	180	Account 904	OX_904	14,475	14,475	0	14,475	0	0	0	0
AF	181	O&M Accounts 902-905	OX_CA	53,614	51,227	2,387	49,594	1,491	143	714	1,673
AF	182										
AF	183	Account 908	OX_908	0	0	0	0	0	0	0	0
AF	184	Account 909	OX_909	0	0	0	0	0	0	0	0
AF	185	Account 910	OX_910	0	0	0	0	0	0	0	0
AF	186	O&M Accounts 908-910	OX_CS	0	0	0	0	0	0	0	0
AF	187	Accounts 901-910	X_CACS	60,310	56,813	3,497	54,962	1,686	165	1,179	2,318
AF	188										
AF	189	Total O&M less Purchased Gas and Uncollectibles	OMXPP	619,719	561,600	58,119	536,745	22,667	2,188	17,667	40,452
AF	190										
AF	191										
AF	192										
AF	193										
AF	194										
AF	195										
AF	196										
AF	197										
AF	198										
AF	199										
AF	200										

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	203										
AF	204	**Labor Expense Related**									
AF	205	Labor Distribution Accounts 870-880	LABORDO	0	0	0	0	0	0	0	0
AF	206	Labor Distribution Accounts 887-894	LABORDM	229,258	207,004	22,254	197,807	8,390	807	6,703	15,551
AF	207	Labor Customer Accounts 902-905	LABORCA	34,261	32,171	2,089	30,741	1,305	125	625	1,465
AF	208	Labor Customer Accounts 908-910	LABORCS	0	0	0	0	0	0	0	0
AF	209	Labor Excluding Admin & Gen	LABORXAG	263,519	239,175	24,344	228,549	9,695	932	7,328	17,016
AF	210	Total Labor Expense	LABOR	274,267	248,930	25,336	237,870	10,090	970	7,627	17,710
AF	211										
AF	212										
AF	213	Base Rate Sales Revenue	SALESREV	1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
AF	214										
AF	215	Claimed Rate Sales Revenue	CLAIMREV	2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
AF	216										
AF	217	Residential Space Heating	SREVRESSH	1,730,861	1,730,861	0	1,730,861	0	0	0	0
AF	218	Residential Domestic	SREVRESD	69,231	69,231	0	0	69,231	0	0	0
AF	219	Residential Other	SREVRESO	7,058	7,058	0	0	0	7,058	0	0
AF	220	General Service Commercial	SREVGSC	68,112	0	68,112	0	0	0	68,112	0
AF	221	Commercial Space Heating	SREVCSH	153,423	0	153,423	0	0	0	0	153,423
AF	222			2,028,685							
AF	223										
AF	224										
AF	225										
AF	226										
AF	227										
AF	228										
AF	229										
AF	230										
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Pike County Light & Power Company
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12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AF	251	**REVENUES AND BILLING DETERMINANTS**									
AF	252										
AF	253										
AF	254	**PRESENT REVENUES FROM SALES INPUT**									
AF	255										
AF	256	Total Sales of Gas Revenues		1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
AF	257	Total Delivery Revenues - Actual		892,835	735,221	157,614	710,266	22,013	2,942	68,771	88,843
AF	258	Total Delivery Revenues - Weather Adjustment		91,543	79,776	11,768	77,345	2,107	323	3,321	8,447
AF	259	DSIC Revenues rolled into Base		101,956	78,070	23,886	75,507	2,249	313	10,787	13,099
AF	260										
AF	261			984,378							
AF	262						77,345	2,107	323	3,321	8,447
AF	263										
AF	264	**12 Months Ending September 30,2024**									
AF	265	**BILLING DETERMINATE INPUTS**									
AF	266	Annual Booked Throughput Sales (Ccf)	SCH AF, LN 23	1,509,018	1,100,928	408,090	1,066,077	30,422	4,429	181,919	226,171
AF	267	Number of Customer Bills	SCH AF, LN 75	16,459	15,455	1,004	14,768	627	60	300	704
AF	268	Average Use Per Customer		92	71	406	72	49	74	606	321
AF	269										
AF	270										
AF	271	**RATE OF RETURN**									
AF	272	Rate of Return (Equalized)	SCH AF, LN 272	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
AF	273										
AF	274										
AF	275										
AF	276										
AF	277										
AF	278										
AF	279										
AF	280	**12 Months Ended September 30, 2025**									
AF	281	**BILLING DETERMINATE INPUTS**									
AF	282	Annual Booked Throughput Sales (Ccf)		1,526,104	1,116,578	409,525	1,081,232	30,855	4,492	182,559	226,966
AF	283	Number of Customer Bills		17,040	16,008	1,032	15,295	651	63	310	722
AF	284	Average Use Per Customer		90	70	397	71	47	72	590	314
AF	285										
AF	286										
AF	287										
AF	288										
AF	289										
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AF	299										
AF	300										

Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AP	1	**ALLOCATION PROPORTIONS TABLE**									
AP	2	**EXTERNALLY DEVELOPED ALLOCATION FACT(**									
AP	3										
AP	4	**CAPACITY**									
AP	5										
AP	6										
AP	7										
AP	8										
AP	9										
AP	10										
AP	11	CAPACITY - DISTRIBUTION RELATED (Design Da									
AP	12	Capacity Distribution	DDIST	1.00000	0.78110	0.21890	0.75747	0.02047	0.00315	0.07780	0.14111
AP	13										
AP	14										
AP	15										
AP	16										
AP	17										
AP	18										
AP	19										
AP	20	**COMMODITY**									
AP	21	Annual Gas Cost (PGC)	EGAS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	22										
AP	23	Annual Gas Deliveries - Thruput (CCF)	ETHRUPUT	1.00000	0.72957	0.27043	0.70647	0.02016	0.00294	0.12055	0.14988
AP	24										
AP	25										
AP	26										
AP	27										
AP	28										
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Pike County Light & Power Company
Gas Class Cost of Service Study
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	53										
AP	54	**CUSTOMER**									
AP	55	Distribution Mains	CUSTDIST	1.00000	0.93883	0.06117	0.89699	0.03817	0.00367	0.01835	0.04282
AP	56										
AP	57	Service Investment	CUSTSERV	1.00000	0.90293	0.09707	0.86281	0.03660	0.00352	0.02924	0.06783
AP	58	Meter Investment	CUSTMET	1.00000	0.75559	0.24441	0.72203	0.03062	0.00294	0.07362	0.17079
AP	59	Meter Installations	CUSTMETIN	1.00000	0.91155	0.08845	0.87105	0.03694	0.00355	0.02664	0.06181
AP	60	Regulators Investment	CUSTREGUL	1.00000	0.93924	0.06076	0.89751	0.03807	0.00366	0.01830	0.04246
AP	61	Regulators Investment - House	CUSTREGULH	1.00000	1.00000	0.00000	0.95557	0.04053	0.00390	0.00000	0.00000
AP	62	Regulators Investment - Industrial	CUSTREGULI	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.30120	0.69880
AP	63	Customer Deposits	CUSTDEP	1.00000	0.09652	0.90348	0.09652	0.00000	0.00000	0.84759	0.05589
AP	64										
AP	65										
AP	66										
AP	67	902-Meter Reading Expense	CUSTMTRDG	1.00000	0.93924	0.06076	0.89751	0.03807	0.00366	0.01830	0.04246
AP	68	903-Customer Records and Collections	CUSTREC	1.00000	0.93900	0.06100	0.89726	0.03809	0.00365	0.01823	0.04277
AP	69										
AP	70	908-Customer Assistance	CUSTASST	1.00000	0.83420	0.16580	0.80173	0.02917	0.00330	0.06945	0.09635
AP	71	909-Informational and Instructional Advertising	CUSTADVT	1.00000	0.83420	0.16580	0.80173	0.02917	0.00330	0.06945	0.09635
AP	72	910-Miscellaneous Customer Service	CUSTCSM	1.00000	0.83420	0.16580	0.80173	0.02917	0.00330	0.06945	0.09635
AP	73	916-Miscellaneous Sales Expense	CUSTSALES	1.00000	0.83420	0.16580	0.80173	0.02917	0.00330	0.06945	0.09635
AP	74										
AP	75	Number of Bills	CUSTBILLS	1.00000	0.93900	0.06100	0.89726	0.03809	0.00365	0.01823	0.04277
AP	76	Number of Customers (Average Annual)	CUST	1.00000	0.93883	0.06117	0.89699	0.03817	0.00367	0.01835	0.04282
AP	77										
AP	78										
AP	79										
AP	80										
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	103	**Plant Related**									
AP	104	Intangible Plant	INTPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	105	Distribution Plant in Service	DISTPLT	1.00000	0.87581	0.12419	0.84004	0.03232	0.00345	0.04079	0.08340
AP	106	Distribution Plant in Service - Capacity Related	DDISTPLT	1.00000	0.93101	0.06899	0.89008	0.03729	0.00364	0.02130	0.04769
AP	107	General Plant in Service	GENLPLT	1.00000	0.90762	0.09238	0.86730	0.03679	0.00354	0.02781	0.06457
AP	108	Common Plant in Service	COMPLT	1.00000	0.90762	0.09238	0.86730	0.03679	0.00354	0.02781	0.06457
AP	109	Total Gas Utility Plant In Service	TOTPLT	1.00000	0.87733	0.12267	0.84134	0.03253	0.00345	0.04017	0.08250
AP	110	Distribution Plant Excl Asset Retirement	DISTPLTXAR	1.00000	0.87581	0.12419	0.84004	0.03232	0.00345	0.04079	0.08340
AP	111	Total Distribution and General Plant	DGPLT	1.00000	0.87744	0.12256	0.84144	0.03255	0.00345	0.04013	0.08243
AP	112	Rate Base	RATEBASE	1.00000	0.88440	0.11560	0.84813	0.03279	0.00348	0.03329	0.08231
AP	113										
AP	114	Account 374 - Land & Land Rights	PLT_374	1.00000	0.78110	0.21890	0.75747	0.02047	0.00315	0.07780	0.14111
AP	115	Account 375 - Structures & Improvements	PLT_375	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	116	Account 376 - Mains	PLT_376	1.00000	0.87247	0.12753	0.83829	0.03072	0.00345	0.04336	0.08417
AP	117	Account 378 - Meas & Reg Station Equip-General	PLT_378	1.00000	0.78110	0.21890	0.75747	0.02047	0.00315	0.07780	0.14111
AP	118	Account 380 - Services	PLT_380	1.00000	0.90293	0.09707	0.86281	0.03660	0.00352	0.02924	0.06783
AP	119	Account 381 - Meters	PLT_381	1.00000	0.75559	0.24441	0.72203	0.03062	0.00294	0.07362	0.17079
AP	120	Account 382 - Meter Installations	PLT_382	1.00000	0.91155	0.08845	0.87105	0.03694	0.00355	0.02664	0.06181
AP	121	Account 384-House Regulator Installations	PLT_384	1.00000	1.00000	0.00000	0.95557	0.04053	0.00390	0.00000	0.00000
AP	122	Account 385-Industrial Regulators	PLT_385	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.30120	0.69880
AP	123	Account 387 - Other Equipment	PLT_387	1.00000	1.00000	0.00000	0.95557	0.04053	0.00390	0.00000	0.00000
AP	124	Account 388-Asset Retirement Costs for Distributior	PLT_388	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.30120	0.69880
AP	125	Accounts 376 & 378 - Mains & M&R	PLT_376379	1.00000	0.86979	0.13021	0.83592	0.03042	0.00344	0.04437	0.08584
AP	126	Accounts 376 & 380 - Mains & Services	PLT_376380	1.00000	0.88100	0.11900	0.84516	0.03237	0.00347	0.03941	0.07960
AP	127	Accounts 380 & 381 - Services & Meters	PLT_380381	1.00000	0.90293	0.09707	0.86281	0.03660	0.00352	0.02924	0.06783
AP	128	Accounts 381 through 385	PLT_3815	1.00000	0.84660	0.15340	0.80899	0.03431	0.00330	0.04620	0.10719
AP	129	Accounts 378 & 387	PLT_378387	1.00000	0.79590	0.20410	0.77087	0.02183	0.00320	0.07253	0.13156
AP	130										
AP	131	Distribution Plant in Service - Capacity Related									
AP	132	Residential Space Heating	DPLTRESSH	1.00000	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	133	Residential Domestic	DPLTRESD	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	134	Residential Other	DPLTRESO	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	135	General Service Commercial	DPLTGSC	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	136	Commercial Space Heating	DPLTCSH	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	137										
AP	138										
AP	139										
AP	140										
AP	141										
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AP	144										
AP	145										
AP	146										
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AP	150										

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		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	153										
AP	154	**Production Expense Related**									
AP	155	Other Production Operation Expense	OX_PRODO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	156										
AP	157										
AP	158										
AP	159			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	160			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	161										
AP	162										
AP	163	**Distribution Expense Related**									
AP	164	Account 874 - Mains & Services Exp	OX_874	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	165	Account 875 - Meas & Reg Station Exp - Gen	OX_875	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	166	Account 878-Meter & House Regulator Expenses	OX_878	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	167	Account 880 - Other Dist Oper Exp	OX_880	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	168	Account 887 - Maint of Mains Exp	MX_887	1.00000	0.87247	0.12753	0.83829	0.03072	0.00345	0.04336	0.08417
AP	169	Account 889 - Maint of Meas & Reg Station Exp - G	MX_889	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	170	Account 892 - Maint of Services Exp	MX_892	1.00000	0.90293	0.09707	0.86281	0.03660	0.00352	0.02924	0.06783
AP	171	Account 893 - Maint of Meter & House Reg Exp	MX_893	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	172	Account 894 - Maint of Other Equipment Exp	MX_894	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	173	O&M Accounts 874-880	OX_DIST	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	174	O&M Accounts 887-894	MX_DIST	1.00000	0.90293	0.09707	0.86281	0.03660	0.00352	0.02924	0.06783
AP	175										
AP	176										
AP	177	**Customer Distribution Expense Related**									
AP	178	Account 902	OX_902	1.00000	0.93924	0.06076	0.89751	0.03807	0.00366	0.01830	0.04246
AP	179	Account 903	OX_903	1.00000	0.93900	0.06100	0.89726	0.03809	0.00365	0.01823	0.04277
AP	180	Account 904	OX_904	1.00000	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	181	O&M Accounts 902-905	OX_CA	1.00000	0.95548	0.04452	0.92501	0.02781	0.00266	0.01331	0.03121
AP	182										
AP	183	Account 908	OX_908	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	184	Account 909	OX_909	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	185	Account 910	OX_910	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	186	O&M Accounts 908-910	OX_CS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	187	Accounts 901-910	X_CACS	1.00000	0.94202	0.05798	0.91132	0.02796	0.00273	0.01954	0.03844
AP	188										
AP	189	Total O&M less Purchased Gas and Uncollectibles	OMXPP	1.00000	0.90622	0.09378	0.86611	0.03658	0.00353	0.02851	0.06527
AP	190										
AP	191										
AP	192										
AP	193										
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AP	199										
AP	200										

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL GAS COMPANY (c)	Total Residential SC1 (a)	Total Commercial SC2 (e)	Residential Space Heating Rate 231 (f)	Residential Domestic Rate 631 (g)	Residential Other Rate 531 & 731 (h)	General Service Commercial Rate 162 (i)	Commercial Space Heating Rate 331 (j)
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	203										
AP	204	**Labor Expense Related**									
AP	205	Labor Distribution Accounts 870-880	LABORDO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	206	Labor Distribution Accounts 887-894	LABORDM	1.00000	0.90293	0.09707	0.86281	0.03660	0.00352	0.02924	0.06783
AP	207	Labor Customer Accounts 902-905	LABORCA	1.00000	0.93902	0.06098	0.89728	0.03809	0.00365	0.01823	0.04275
AP	208	Labor Customer Accounts 908-910	LABORCS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	209	Labor Excluding Admin & Gen	LABORXAG	1.00000	0.90762	0.09238	0.86730	0.03679	0.00354	0.02781	0.06457
AP	210	Total Labor Expense	LABOR	1.00000	0.90762	0.09238	0.86730	0.03679	0.00354	0.02781	0.06457
AP	211										
AP	212										
AP	213	Base Rate Sales Revenue	SALESREV	1.00000	0.82209	0.17791	0.79452	0.02427	0.00329	0.07629	0.10162
AP	214										
AP	215	Claimed Rate Sales Revenue	CLAIMREV	1.00000	0.89080	0.10920	0.85319	0.03413	0.00348	0.03357	0.07563
AP	216										
AP	217	Residential Space Heating	SREVRESSH	1.00000	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	218	Residential Domestic	SREVRESD	1.00000	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	219	Residential Other	SREVRESO	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	220	General Service Commercial	SREVGSC	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	221	Commercial Space Heating	SREVCSH	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	222										
AP	223										
AP	224										
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Pike County Light & Power Company
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SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
AP	251	**REVENUES AND BILLING DETERMINANTS**									
AP	252										
AP	253										
AP	254	**PRESENT REVENUES FROM SALES INPUT**									
AP	255										
AP	256	Total Sales of Gas Revenues		1.00000	0.82209	0.17791	0.79452	0.02427	0.00329	0.07629	0.10162
AP	257	Total Delivery Revenues - Actual		1.00000	0.82347	0.17653	0.79552	0.02466	0.00329	0.07703	0.09951
AP	258	Total Delivery Revenues - Weather Adjustment									
AP	259	DSIC Revenues rolled into Base									
AP	260										
AP	261										
AP	262										
AP	263										
AP	264	12 Months Ending September 30,2024									
AP	265										
AP	267										
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Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**									
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
ADA	3										
ADA	4	**Net Write-Offs**									
ADA	5	Residential Space Heating	SREVRESSH	15,883	15,883	0	15,883	0	0	0	0
ADA	6	Residential Domestic	SREVRESD	0	0	0	0	0	0	0	0
ADA	7	Residential Other	SREVRESO	0	0	0	0	0	0	0	0
ADA	8	General Service Commercial	SREVGSC	0	0	0	0	0	0	0	0
ADA	9	Commercial Space Heating	SREVCSH	0	0	0	0	0	0	0	0
ADA	10										
ADA	11										
ADA	12	Total Write-Offs	EXP_904	15,883	15,883	0	15,883	0	0	0	0
ADA	13										
ADA	14	Total Write-Offs	EXP_904	1.00000	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
ADA	15										
ADA	16										
ADA	17										
ADA	18										
ADA	19	**Forfeited Discounts - Account 487**									
ADA	20	Residential Space Heating	SREVRESSH	5,123	5,123	0	5,123	0	0	0	0
ADA	21	Residential Domestic	SREVRESD	125	125	0	0	125	0	0	0
ADA	22	Residential Other	SREVRESO	28	28	0	0	0	28	0	0
ADA	23	General Service Commercial	SREVGSC	595	0	595	0	0	0	595	0
ADA	24	Commercial Space Heating	SREVCSH	661	0	661	0	0	0	0	661
ADA	25										
ADA	26										
ADA	27	Total Forfeited Discounts	REV_487	6,532	5,276	1,256	5,123	125	28	595	661
ADA	28										
ADA	29	Total Forfeited Discounts	REV_487	1.00000	0.80767	0.19233	0.78425	0.01907	0.00435	0.09108	0.10125
ADA	30										
ADA	31										
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Pike County Light & Power Company
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12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**									
RRW	2										
RRW	3	PRESENT RATE OF RETURN (EXISTING RATES)									
RRW	4	--									
RRW	5	Rate Base		7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
RRW	6	Net Operating Income (Present Rates)		300,104	204,500	95,605	202,143	1,440	917	46,249	49,355
RRW	7	Rate of Return @ Present Rates		4.29%	3.30%	11.81%	3.40%	0.63%	3.76%	19.84%	8.56%
RRW	8	Relative Rate of Return		1.00	0.77	2.76	0.79	0.15	0.88	4.63	2.00
RRW	9	Sales Revenue at Present Rates		1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
RRW	10	Revenue Present Rates $/Ccf		$711.8354	$799.8246	$471.9309	$798.2741	$854.6320	$796.5648	$453.9848	$486.3658
RRW	11	Revenue Required - $/Month/Customer		$66,002.46	$57,784.98	$192,497.60	$58,445.23	$42,056.61	$59,637.37	$276,262.96	$156,802.13
RRW	12										
RRW	13										
RRW	14	CLAIMED RATE OF RETURN									
RRW	15	--									
RRW	16	Claimed Rate of Return		8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
RRW	17	Return Required for Claimed Rate of Return		917,310	809,432	107,878	776,197	30,048	3,187	32,525	75,353
RRW	18	Sales Revenue Required @ Claimed ROR		2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
RRW	19	Sales Revenue Deficiency		942,350	914,083	28,267	867,742	42,861	3,480	(14,767)	43,034
RRW	20	Percent Increase Required		86.75%	102.35%	14.63%	100.54%	162.54%	97.25%	-17.82%	38.98%
RRW	21	Annual Booked Throughput Sales (Ccf)		1,526,104	1,116,578	409,525	1,081,232	30,855	4,492	182,559	226,966
RRW	22	Sales Revenue Required $/Ccf		$1,329.3230	$1,618.4710	$540.9553	$1,600.8234	$2,243.7594	$1,571.2626	$373.0969	$675.9710
RRW	23	Sales Revenue Deficiency $/Ccf		$617.4877	$818.6464	$69.0244	$802.5493	$1,389.1274	$774.6978	($80.8879)	$189.6052
RRW	24										
RRW	25										
RRW	26	PROPOSED RATE OF RETURN									
RRW	27	--									
RRW	28	Rate Base at Future Test Year 09/30/2025		10,679,156	9,423,260	1,255,896	9,036,345	349,808	37,108	378,655	877,240
RRW	29	Proposed Base Gas Sales Revenues		2,028,685	1,781,499	247,186	1,723,140	51,209	7,150	106,165	141,021
RRW	30	Base Sales Revenue Deficiency		942,351	888,432	53,919	860,021	24,840	3,572	23,286	30,633
RRW	31	Return Required for Proposed Revenue		2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
RRW	32	Percent Increase Required at Proposed Rates		86.75%	99.48%	27.90%	99.64%	94.20%	99.81%	28.10%	27.75%
RRW	33	Proposed Rate of Return		19.00%	19.18%	17.64%	19.15%	19.79%	19.02%	17.99%	17.49%
RRW	34	Relative Rate of Return		1.00	1.01	0.93	1.01	1.04	1.00	0.95	0.92
RRW	35										
RRW	36										
RRW	37										
RRW	38										
RRW	39										
RRW	40										
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RRW	48										
RRW	49										
RRW	50										

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

LINE NO.	DESCRIPTION		TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
	(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
1	**PRESENT RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**									
2										
3	**RATE OF RETURN**		4.29%	3.30%	11.81%	3.40%	0.63%	3.76%	19.84%	8.56%
4										
5	**REVENUES REQUIRED**									
6	**CAPACITY COMPONENT**	133,445	133,445	62,241	71,204	61,877	87	278	40,495	30,708
7	CAPACITY PRODUCTION COMPONENT		0	0	0	0	0	0	0	0
8	CAPACITY TRANSMISSION COMPONENT		0	0	0	0	0	0	0	0
9	CAPACITY DISTRIBUTION MAINS		133,445	62,241	71,204	61,877	87	278	40,495	30,708
10	**COMMODITY COMPONENT**	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
11	COMMODITY PURCHASED GAS		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
12	COMMODITY OTHER COMMODITY		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
13	**CUSTOMER COMPONENT**	952,890	952,890	830,826	122,064	801,243	26,283	3,301	42,383	79,680
14	CUSTOMER DISTRIBUTION MAINS		113,452	89,354	24,098	89,009	(50)	395	12,284	11,814
15	CUSTOMER SERVICES INVESTMENT		701,955	614,856	87,099	590,343	22,107	2,407	32,183	54,915
16	CUSTOMER METERS & INSTALL INVESTMENT		39,002	28,435	10,567	27,956	359	120	5,106	5,461
17	CUSTOMER REGULATORS		5,775	206	5,569	210	(5)	1	2,688	2,881
18	CUSTOMER SERVICE & SALES EXPENSE		6,780	5,671	1,108	5,452	197	22	462	647
19	CUSTOMER ACCOUNTS EXPENSE		85,927	92,304	(6,377)	88,274	3,674	356	(10,339)	3,962
20										
21										
22	**TOTAL COMPANY**	1,086,334	1,086,334	893,067	193,268	863,119	26,369	3,578	82,879	110,389
23										
24										
25										
26										
27	Annual Booked Throughput Sales (Ccf)		1,509,018	1,100,928	408,090	1,066,077	30,422	4,429	181,919	226,171
28	Average Use Per Customer		92	71	406	72	49	74	606	321
29	Number of Customer Bills		16,459	15,455	1,004	14,768	627	60	300	704
30										
31	Use per Month per Customer		91.68	71.23	406.46	72.19	48.52	73.82	606.40	321.27
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Pike County Light & Power Company
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12 Months Ending September 30,2024

LINE NO.	DESCRIPTION		TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
	(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
1	**PRESENT RATE OF RETURN SUMMARY SCHEDULE - UNIT COST**									
2										
3	**RATE OF RETURN**		4.29%	3.30%	11.81%	3.40%	0.63%	3.76%	19.84%	8.56%
4										
5	**$/Ccf**									
6	**CAPACITY COMPONENT**	$87.4416	$87.4416	$55.7426	$173.8693	$57.2279	$2.8163	$61.7882	$221.8214	$135.2995
7	CAPACITY PRODUCTION COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	CAPACITY DISTRIBUTION MAINS		$87.4416	$55.7426	$173.8693	$57.2279	$2.8163	$61.7882	$221.8214	$135.2995
9	**COMMODITY COMPONENT**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	COMMODITY PURCHASED GAS		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
11	COMMODITY OTHER COMMODITY		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
12	**CUSTOMER COMPONENT**	$624.3938	$624.3938	$744.0820	$298.0616	$741.0462	$851.8158	$734.7766	$232.1634	$351.0663
13	CUSTOMER DISTRIBUTION MAINS		$74.3409	$80.0246	$58.8441	$82.3216	($1.6099)	$87.8753	$67.2904	$52.0503
14	CUSTOMER SERVICES INVESTMENT		$459.9653	$550.6609	$212.6819	$545.9909	$716.4781	$535.7654	$176.2900	$241.9534
15	CUSTOMER METERS & INSTALL INVESTMENT		$25.5563	$25.4659	$25.8029	$25.8555	$11.6263	$26.7486	$27.9672	$24.0620
16	CUSTOMER REGULATORS		$3.7840	$0.1843	$13.5987	$0.1938	($0.1533)	$0.2147	$14.7238	$12.6937
17	CUSTOMER SERVICE & SALES EXPENSE		$4.4426	$5.0792	$2.7067	$5.0424	$6.3891	$4.9504	$2.5281	$2.8504
18	CUSTOMER ACCOUNTS EXPENSE		$56.3047	$82.6669	($15.5726)	$81.6420	$119.0855	$79.2223	($56.6360)	$17.4565
19										
20										
21	**TOTAL COMPANY**	$711.8354	$711.8354	$799.8246	$471.9309	$798.2741	$854.6320	$796.5648	$453.9848	$486.3658
22										
23	**$/MONTH/CUSTOMER**									
24	**CUSTOMER COMPONENTS**	$57.89	$57.89	$53.76	$121.58	$54.26	$41.92	$55.01	$141.28	$113.18
25	CUSTOMER DISTRIBUTION MAINS		$6.89	$5.78	$24.00	$6.03	($0.08)	$6.58	$40.95	$16.78
26	CUSTOMER SERVICES INVESTMENT		$42.65	$39.78	$86.75	$39.97	$35.26	$40.11	$107.28	$78.00
27	CUSTOMER METERS & INSTALL INVESTMENT		$2.37	$1.84	$10.52	$1.89	$0.57	$2.00	$17.02	$7.76
28	CUSTOMER REGULATORS		$0.35	$0.01	$5.55	$0.01	($0.01)	$0.02	$8.96	$4.09
29	CUSTOMER SERVICE & SALES EXPENSE		$0.41	$0.37	$1.10	$0.37	$0.31	$0.37	$1.54	$0.92
30	CUSTOMER ACCOUNTS EXPENSE		$5.22	$5.97	($6.35)	$5.98	$5.86	$5.93	($34.46)	$5.63
31										
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Pike County Light & Power Company
Gas Class Cost of Service Study
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LINE NO.	DESCRIPTION		TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
	(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
1	**CLAIMED RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**									
2	(For Future Test Year 12 Months Ended September 30 2025)									
3	**RATE OF RETURN**		8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
4										
5	**REVENUES REQUIRED**									
6	**CAPACITY COMPONENT**	342,986	342,986	268,201	74,785	260,115	7,008	1,078	26,542	48,242
7	CAPACITY PRODUCTION COMPONENT		(0)	(0)	(0)	(0)	(0)	0	(0)	(0)
8	CAPACITY DISTRIBUTION MAINS		342,986	268,201	74,785	260,115	7,008	1,078	26,542	48,242
9	**COMMODITY COMPONENT**	0	0	0	0	0	0	0	0	0
10	COMMODITY PURCHASED GAS		0	0	0	0	0	0	0	0
11	COMMODITY OTHER COMMODITY		0	0	0	0	0	0	0	0
12	**CUSTOMER COMPONENT**	1,685,698	1,685,698	1,538,948	146,750	1,470,746	62,223	5,980	41,570	105,180
13	CUSTOMER DISTRIBUTION MAINS		436,764	410,170	26,594	391,947	16,626	1,597	7,967	18,627
14	CUSTOMER SERVICES INVESTMENT		1,013,128	915,185	97,943	874,655	36,977	3,553	29,468	68,475
15	CUSTOMER METERS & INSTALL INVESTMENT		111,398	99,560	11,838	95,150	4,023	386	3,561	8,277
16	CUSTOMER REGULATORS		7,908	1,432	6,476	1,369	58	6	1,948	4,528
17	CUSTOMER SERVICE & SALES EXPENSE		6,978	5,825	1,153	5,599	203	23	482	670
18	CUSTOMER ACCOUNTS EXPENSE		109,522	106,776	2,746	102,025	4,336	415	(1,856)	4,603
19										
20										
21	**TOTAL COMPANY**	2,028,685	2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
22										
23										
24										
25	**12 Months Ended September 30, 2025**									
26	Annual Booked Throughput Sales (Ccf)		1,526,104	1,116,578	409,525	1,081,232	30,855	4,492	182,559	226,966
28	Number of Customer Bills		17,040	16,008	1,032	15,295	651	63	310	722
27	Average Use Per Customer		92	71	406	72	49	74	606	321
29										
30										
31										
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Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

LINE NO.	DESCRIPTION		TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
	(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
1	**CLAIMED RATE OF RETURN SUMMARY SCHEDULE - UNIT COSTS**									
2	(For Future Test Year 12 Months Ended September 30 2025)									
3	**RATE OF RETURN**		8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%	8.59%
4										
5	**$/Ccf**									
6	**CAPACITY COMPONENT**	$224.7464	$224.7464	$240.1993	$182.6137	$240.5731	$227.1204	$240.0607	$145.3915	$212.5531
7	CAPACITY PRODUCTION COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	CAPACITY DISTRIBUTION MAINS		$224.7464	$240.1993	$182.6137	$240.5731	$227.1204	$240.0607	$145.3915	$212.5531
9	**COMMODITY COMPONENT**	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
10	COMMODITY PURCHASED GAS		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
11	COMMODITY OTHER COMMODITY		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
12	**CUSTOMER COMPONENT**	$1,104.5766	$1,104.5766	$1,378.2716	$358.3416	$1,360.2503	$2,016.6390	$1,331.2019	$227.7054	$463.4179
13	CUSTOMER DISTRIBUTION MAINS		$286.1958	$367.3457	$64.9390	$362.5004	$538.8513	$355.5708	$43.6391	$82.0714
14	CUSTOMER SERVICES INVESTMENT		$663.8661	$819.6335	$239.1633	$808.9436	$1,198.4175	$790.9028	$161.4181	$301.6971
15	CUSTOMER METERS & INSTALL INVESTMENT		$72.9949	$89.1651	$28.9065	$88.0018	$130.3840	$86.0382	$19.5047	$36.4688
16	CUSTOMER REGULATORS		$5.1816	$1.2825	$15.8127	$1.2658	$1.8754	$1.2375	$10.6698	$19.9493
17	CUSTOMER SERVICE & SALES EXPENSE		$4.5722	$5.2169	$2.8143	$5.1784	$6.5794	$5.1140	$2.6425	$2.9525
18	CUSTOMER ACCOUNTS EXPENSE		$71.7660	$95.6280	$6.7058	$94.3602	$140.5314	$92.3386	($10.1688)	$20.2787
19										
20										
21	**TOTAL COMPANY**	$1,329.3230	$1,329.3230	$1,618.4710	$540.9553	$1,600.8234	$2,243.7594	$1,571.2626	$373.0969	$675.9710
22										
23	**$/MONTH/CUSTOMER**									
24	**CUSTOMER COMPONENTS**	$98.93	$98.93	$96.14	$142.20	$96.16	$95.61	$95.56	$134.27	$145.60
25	CUSTOMER DISTRIBUTION MAINS		$25.63	$25.62	$25.77	$25.63	$25.55	$25.52	$25.73	$25.79
26	CUSTOMER SERVICES INVESTMENT		$59.46	$57.17	$94.91	$57.19	$56.81	$56.77	$95.18	$94.79
27	CUSTOMER METERS & INSTALL INVESTMENT		$6.54	$6.22	$11.47	$6.22	$6.18	$6.18	$11.50	$11.46
28	CUSTOMER REGULATORS		$0.46	$0.09	$6.27	$0.09	$0.09	$0.09	$6.29	$6.27
29	CUSTOMER SERVICE & SALES EXPENSE		$0.41	$0.36	$1.12	$0.37	$0.31	$0.37	$1.56	$0.93
30	CUSTOMER ACCOUNTS EXPENSE		$6.43	$6.67	$2.66	$6.67	$6.66	$6.63	($6.00)	$6.37
31										
32										
33										
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The listing of all external allocation factors shown are in pages 15 to 16 of the Allocation Factor Table and pages 20 to 21 of the Ratio Table of Exhibit G-6, Schedule GRP-4-G of the Pike County Light & Power Company embedded gas cost of service study.

DESCRIPTION OF ALLOCATION FACTORS
Reference for Internal Allocators Not Shown in Allocation Factor Table

External Allocators – Capacity Related, Page 15, line 12

1. DDIST – Demand Distribution Allocator.
   Based on the daily sendout at 74 design degree day for all firm rate classes. Allocator Ratio is on Page 21, line 12.

External Allocators – Commodity Related, Page 15, lines 21 and 23

2. EGAS – Commodity Allocator
   Annual Gas Costs (PGC) – not currently used in this study.
   Allocator Ratio is on Page 21, line 21.

3. ETHRUPUT – Commodity Allocator
   Annual Gas Deliveries – Throughput (Ccf). Allocator Ratio is on Page 21, line 23.

External Allocators – Customer Related, Page 16, lines 55 to 73

4. CUSTDIST – Acct 376 – Customer Distribution Function.
   This allocator represents the average annual number of customers.
   Allocation Ratio is on Page 22, line 55.

5. CUSTSERV – Acct 380 Service Investment – Customer Services Function.
   This allocator represents the direct assignment of service plant account to the customer classes. See Workpapers for details. Allocation Ratio is on Page 22, line 57.

6. CUSTMET – Acct 381 Meter Investments – Customer Meters Function.
   This allocator represents the direct assignment of meter plant account to the customer classes. See Workpapers for detail. Allocation Ratio is on Page 22, line 58.

7. CUSTMETIN – Acct 382 – Meter Installations – Customer Meters Function.
   This allocator represents the assignment of plant to classes. See Workpapers for detail. Allocation Ratio is on Page 22, line 59.

8. CUSTREGUL – Acct 384 & 385 – Regulators Investment – Customer Regulators Function. This allocator represents the assignment of plant to classes. See Workpapers for detail. Allocation Ratio is on Page 22, line 60.

DESCRIPTION OF ALLOCATION FACTORS
Reference for Internal Allocators Not Shown in Allocation Factor Table

External Allocators – Customer Related, Page 16, lines 55 to 73, continued

9. CUSTDEP – Customer Deposits – Customer Other Function
This allocator represents the direct assignment of customer deposits to the customer classes. See Workpapers for detail. Allocation Ratio is on Page 22, line 63.

10. CUSTMTRDG – Acct 902 Meter Reading Expense – Customer Accounts Expense Function
This allocator was based on the number of meters by rate class. Allocation Ratio is on Page 22, line 67.

11. CUSTREC – Acct 903 Customer Records & Collection Expenses – Customer Accounts Expense Function
This allocator was based on the number of bills by rate class. Allocation Ratio is on Page 22, line 68.

12. CUSTASST – Customer Assistance Expense – Customer Services Expense Function
This allocator was developed internally in the cost of service model. Since these costs are not totally related to the total number of customers or the amount of sales, a weighted allocation factor was developed. The allocator is based on a 50% weighting on the annual number of customers (Page 22, line 76) and a 50% weighting on the total annual throughput Ccf sales at the meters (Page 21, line 23). Allocation Ratio is on Page 22, line 70.

13. CUSTADVT – Customer Informational Advertising Expenses – Customer Service Expense Function
This allocator was developed in the same manner as the CUSTASST allocator. Allocation Ratio is on Page 22, line 71.

14. CUSTCSM – Miscellaneous Customer Assistance Expenses – Customer Service Expense Function
This allocator was developed in the same manner as the CUSTASST allocator. Allocation Ratio is on Page 22, line 72.

15. CUSTSALES – Demonstrating and Selling Expenses – Sales Expense Function
This allocator was developed in the same manner as the CUSTASST allocator. Allocation Ratio is on Page 22, line 73.

DESCRIPTION OF ALLOCATION FACTORS
Reference for Internal Allocators Not Shown in Allocation Factor Table

External Allocators – Revenue Related, Page 27

16. EXP_904 – Account 904 – Uncollectible Accounts
This allocator is a direct assignment allocator that was developed using write-offs by class. The allocator is on Page 27, line 12, and the Allocation Ratio is on Page 27, line 14.

17. REV_487 – Account 487 – Late Payment Charges
This allocator is a direct assignment allocator that was developed using the forfeited discounts by class. The allocator is on Page 27, line 27, and the Allocation Ratio is on Page 27, line 29.

Pike County Light & Power Company
Gas Class Cost of Service Study
12 Months Ending September 30,2024

SCH	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL GAS COMPANY	Total Residential SC1	Total Commercial SC2	Residential Space Heating Rate 231	Residential Domestic Rate 631	Residential Other Rate 531 & 731	General Service Commercial Rate 162	Commercial Space Heating Rate 331
		(a)	(b)	(c)	(a)	(e)	(f)	(g)	(h)	(i)	(j)
SUM	1	**HISTORICAL AND FUTURE YEAR DIFFERENCE ADJUSTMENTS:**									
SUM	2	**(For Future Test Year 12 Months Ended September 30 2025)**									
SUM	3										
SUM	4	**OPERATING INCOME (RETURN) @ PRESENT RATES**		300,104	204,500	95,605	202,143	1,440	917	46,249	49,355
SUM	5	**LESS Historical and Future Year Differences:**									
SUM	6	Retail Sales Revenue	CLAIMREV	35,857	31,941	3,916	30,593	1,224	125	1,204	2,712
SUM	7	487-Late Payment Charges	REV_487	(2,500)	(2,019)	(481)	(1,961)	(48)	(11)	(228)	(253)
SUM	8	**PLUS Historical and Future Year Differences:**									
SUM	9	O&M Expense - Labor Related	LABOR	58,700	53,277	5,423	50,910	2,160	208	1,632	3,790
SUM	10	O&M Expense - 904-Uncollectible Accounts	EXP_904	(8,200)	(8,200)	0	(8,200)	0	0	0	0
SUM	11	O&M Expense - 928-Regulatory Commission	CLAIMREV	9,400	8,374	1,026	8,020	321	33	316	711
SUM	12	Depreciation Expense	TOTPLT	124,900	109,578	15,322	105,084	4,064	431	5,018	10,304
SUM	13	TOIT - Base Payroll Taxes	LABOR	3,106	2,819	287	2,694	114	11	86	201
SUM	14	TOIT - PA Property Tax	TOTPLT	(103)	(90)	(13)	(86)	(3)	(0)	(4)	(8)
SUM	15	State Income Taxes	CLAIMREV	(33,515)	(29,581)	(3,935)	(28,329)	(1,132)	(119)	(1,190)	(2,745)
SUM	16	Federal Income Taxes	CLAIMREV	(81,050)	(71,534)	(9,516)	(68,509)	(2,738)	(288)	(2,878)	(6,638)
SUM	17	**OPERATING INCOME @ PRESENT RATES WITH DIFFERENCES**		260,224	169,779	90,445	169,192	(170)	756	44,246	46,199
SUM	18	Operating Income Before Taxes		68,693	(22,291)	90,985	(12,605)	(9,719)	32	51,239	39,745
SUM	19										
SUM	20	**RATE BASE**	SCH SUM, LN 27	7,003,414	6,193,813	809,601	5,939,791	229,619	24,403	233,149	576,452
SUM	21	**Historical and Future Year Difference Adjustments:**									
SUM	22	Gas Utility Plant & Reserves Adjustments	TOTPLT	3,492,842	3,064,373	428,469	2,938,674	113,639	12,060	140,316	288,153
SUM	23	Additions:									
SUM	24	Cash Working Capital	OMXPP	143,400	129,952	13,448	124,200	5,245	506	4,088	9,360
SUM	25	Materials and Supplies	TOTPLT	5,800	5,089	711	4,880	189	20	233	478
SUM	26	Prepayments	TOTPLT	100	88	12	84	3	0	4	8
SUM	27	Deferred Debits (Net of Tax)	TOTPLT	18,200	15,967	2,233	15,312	592	63	731	1,501
SUM	28	Deductions:									
SUM	29	Customer Deposits	CUSTDEP	600	58	542	58	0	0	509	34
SUM	30	Deferred Income Taxes and Credits	TOTPLT	(16,000)	(14,037)	(1,963)	(13,461)	(521)	(55)	(643)	(1,320)
SUM	31	**RATE BASE WITH ADJUSTMENTS**		10,679,156	9,423,260	1,255,896	9,036,345	349,808	37,108	378,655	877,240
SUM	32										
SUM	33	**EQUALIZED RETURN AT PROPOSED ROR OF 8.59%**									
SUM	34	**DEVELOPMENT OF RETURN (RATE BASE * 8.59% ROR)**		917,310	809,432	107,878	776,197	30,048	3,187	32,525	75,353
SUM	35	Additional Return Required * Retention Factor 1.38%		906,521	882,470	24,051	837,428	41,688	3,354	(16,169)	40,220
SUM	36	487-Late Payment Charges	REV_487	2,500	2,019	481	1,961	48	11	228	253
SUM	37	**PLUS OPERATING EXPENSES**									
SUM	38	Operation and Maintenance Expense		696,594	631,545	65,049	603,911	25,195	2,439	19,842	45,206
SUM	39	Depreciation and Amortization Expense		333,061	293,657	39,404	281,352	11,152	1,153	12,666	26,738
SUM	40	Taxes Other Than Income Taxes		27,694	25,037	2,658	23,934	1,005	98	811	1,847
SUM	41	State Income Taxes		16,200	14,159	2,041	13,570	533	55	736	1,305
SUM	42	Federal Income Taxes		39,177	34,240	4,936	32,816	1,290	134	1,780	3,157
SUM	43	**TOTAL OPERATING EXPENSES**		1,112,725	998,638	114,087	955,583	39,176	3,879	35,834	78,253
SUM	44										
SUM	45	**EQUALS TOTAL COST OF SERVICE**		2,030,035	1,808,070	221,965	1,731,780	69,223	7,066	68,360	153,605
SUM	46										
SUM	47	**LESS: Other Operating Revenues**		1,350	920	430	919	(7)	8	248	183
SUM	48	**BASE RATE SALES @ EQUALIZED ROR 8.59%**		2,028,685	1,807,150	221,535	1,730,861	69,231	7,058	68,112	153,423
SUM	49	**BASE RATE SALES REVENUE INCREASE**		942,350	914,083	28,267	867,742	42,861	3,480	(14,767)	43,034
SUM	50										

Pike County Light & Power Company
Gas Rate Design
Test Year 12 Months Ended September 30, 2024
Rate Year 12 Months Ended September 30, 2025

Allocation of Proposed Revenue Adjustments to Base Rates

Line No.	Description (A)	Current Base Sales Revenue (B)	DSIC Revenue (C)	Total Sales Revenue (D)	Increase Target Base Revenue Increase @ Uniform ROR 8.59% (E)	Revenue Increase Capped at 1.96.% of Uniform ROR 8.59% 16.81% (F)	Capped Revenue (G)	Total To Redistribute (H)	Redistributed Capped Revenue (I)
		(1)		(col B + col C)	(2)			(total col E - total col G)	
1	**Rate Schedule:**								
2	SC-1 Residential Space Heating 231	$787,612	$75,507	$863,119	$867,742	$132,398			843,367
3	SC-1 Residential Domestic 631	$24,120	$2,249	$26,369	$42,861	$4,055			41,657
4	SC-1 Residential Other 531 & 731	$3,265	$313	$3,578	$3,480	$549			3,382
5	SC-2 General Service Commercial 162	$72,092	$10,787	$82,879	($14,767)	$12,119	$12,119		
6	SC-2 Commercial Space Heating 331	$97,289	$13,099	$110,389	$43,034	$16,354			41,825
11	**Total**	$984,378	$101,956	$1,086,334	**$942,350**		$12,119	$930,231	$930,231
12									
13						95.7%			
14	**Notes**					Base Increase			
15	(1) Source for columns B and C is file								
16	Pike Gas Revenue Proof 9-30-24 Test Year Rev 11-19-24.xlsx								
17	(2) Source for column E is Exhibit G-6, Sch GRP-3-G, line 19.								
18	(3) Overall Increase is based on col D base sales revenue								
19	calculated using historical volumes and col L proposed base								
20	revenues are calculated using test year volumes.								

Pike County Light & Power Company
Gas Rate Design
Test Year 12 Months Ended September 30, 2024
Rate Year 12 Months Ended September 30, 2025

Allocation of Proposed Revenue Adjustments to Base Rates

Line No.	Description (A)	Target Base Revenue Proposed Increase (J)	Target Proposed Base Revenue (K)	Proposed Total Base Sales Revenue (L)	Base Sales Percent Increase (M)	Overall Increase (N)
		(col G + col I)	(col B + col J)			(3)
1	**Rate Schedule:**					
2	SC-1 Residential Space Heating 231	$843,367	$1,706,486	$1,723,140	118.8%	99.6%
3	SC-1 Residential Domestic 631	$41,657	$68,027	$51,209	112.3%	94.2%
4	SC-1 Residential Other 531 & 731	$3,382	$6,961	$7,150	119.0%	99.8%
5	SC-2 General Service Commercial 162	$12,119	$94,998	$106,165	47.3%	28.1%
6	SC-2 Commercial Space Heating 331	$41,825	$152,214	$141,021	45.0%	27.7%
11	**Total**	$942,350	$2,028,685	$2,028,685	106.1%	86.7%
12				$1 diff		
13						

14 **Notes**
15 (1) Source for columns B and C is file
16 Pike Gas Revenue Proof 9-30-24 Test Year Rev 11-19-24.xlsx
17 (2) Source for column E is Exhibit G-6, Sch GRP-3-G, line 19.
18 (3) Overall Increase is based on col D base sales revenue
19 calculated using historical volumes and col L proposed base
20 revenues are calculated using test year volumes.

Pike County Light & Power Company
Gas Rate Design
Test Year 12 Months Ended September 30, 2024
Rate Year 12 Months Ended September 30, 2025

Base Revenues at Present and Proposed Rates

WEATHER ADJ WITHOUT GAS COSTS

Schedule & Cost Component	Quantity	Units	Present Rates: Base Margin Rate	Present Rates: COG Commodity Rate	Present Rates: Total Rate	Present Rates: Revenue	Quantity	Units	Proposed Rates: Base Margin Rate	Proposed Rates: COG Commodity Rate	Proposed Rates: Total Rate	Proposed Rates: Revenue	Change
			SC-1 Residential Space Heating 231						**SC-1 Residential Space Heating 231**				
SC-1 Residential Space Heating 231													
Customer Charge	14,664	Cust	$8.00		$8.00	$ 117,312	15,295	Cust	$9.50		$9.50	$ 145,299	
Delivery Charge All CCF	1,036,653	CCF	$ 0.6466		$ 0.6466	$ 670,300	1,081,232	CCF	$ 1.4593		$ 1.4593	$ 1,577,841	
Total Revenues						**$ 787,612**						**$ 1,723,140**	**118.8%**
Monthly Use Per Customer (1)									0			$ 1,706,486	Target
Monthly $ per Customers @ Proposed Equalized ROR (2)									$96.16				
			SC-1 Residential Domestic 631						**SC-1 Residential Domestic 631**				
SC-1 Residential Domestic 631													
Customer Charge	624	Cust	$8.00		$8.00	$ 4,992	651	Cust	$9.50		$9.50	$ 6,183	
Delivery Charge All CCF	29,583	CCF	$ 0.6466		$ 0.6466	19,128	30,855	CCF	$ 1.4593		$ 1.4593	$ 45,026	
Total Revenues						**$ 24,120**						**$ 51,209**	**112.3%**
Monthly Use Per Customer (1)									0			$ 68,027	Target
Monthly $ per Customers @ Proposed Equalized ROR (2)									$95.61				
			SC-1 Residential Other 531 & 731						**SC-1 Residential Other 531 & 731**				
SC-1 Residential Other 531 & 731													
Customer Charge	60	Cust	$8.00		$8.00	$ 480	63	Cust	$9.50		$9.50	$ 595	
Delivery Charge - Winter	4,307	CCF	$ 0.6466		$ 0.6466	2,785	4,492	CCF	$ 1.4593		$ 1.4593	$ 6,555	
Total Revenues						**$ 3,265**						**$ 7,150**	**119.0%**
Monthly Use Per Customer (1)									0			$ 6,961	Target
Monthly $ per Customers @ Proposed Equalized ROR (2)									$95.56				
Total Residential Customers	**15,348**						**16,008**						
Total Residential CCF	**1,070,543**						**1,116,578**						

Pike County Light & Power Company
Gas Rate Design
Test Year 12 Months Ended September 30, 2024
Rate Year 12 Months Ended September 30, 2025

Base Revenues at Present and Proposed Rates

WEATHER ADJ WITHOUT GAS COSTS

		Present Rates						Proposed Rates						
	Schedule & Cost Component	**Quantity**	**Units**	**Base Margin Rate**	**COG Commodity Rate**	**Total Rate**	**Revenue**	**Quantity**	**Units**	**Base Margin Rate**	**COG Commodity Rate**	**Total Rate**	**Revenue**	**Change**
45				**SC-2 General Service Commercial 162**						**SC-2 General Service Commercial 162**				
46	**SC-2 General Service Commercial 162**													
48	Customer Charge	300	Cust	$12.23		$12.23	$ 3,669	310	Cust	$14.25		$14.25	$ 4,412	
50	Delivery Charge - First 300 CCF	37,719	CCF	$ 0.5089		$ 0.5089	19,195	38,926	CCF	$ 0.6938		$ 0.6938	$ 27,007	
51	Delivery Charge - All Over 300 CCF	139,179	CCF	$ 0.3537		$ 0.3537	49,228	143,633	CCF	$ 0.5204		$ 0.5204	$ 74,746	
52	Subtotal Delivery Charges	176,898					$ 68,423	182,559					$ 101,753	
54	**Total Revenues**						**$ 72,092**						**$ 106,165**	**47.3%**
56	**Monthly Use Per Customer (1)**									0			$ 94,998	Target
57	**Monthly $ per Customers @ Proposed Equalized ROR (2)**									$134.27				
62				**SC-2 Commercial Space Heating 331**						**SC-2 Commercial Space Heating 331**				
63	**SC-2 Commercial Space Heating 331**													
65	Customer Charge	700	Cust	$12.23		$12.23	$ 8,561	722	Cust	$14.25		$14.25	$ 10,294	
67	Delivery Charge - First 300 CCF	70,488	CCF	$ 0.5089		$ 0.5089	35,871	72,743	CCF	$ 0.6938		$ 0.6938	$ 50,469	
68	Delivery Charge - All Over 300 CCF	149,441	CCF	$ 0.3537		$ 0.3537	52,857	154,223	CCF	$ 0.5204		$ 0.5204	$ 80,258	
69	Subtotal Delivery Charges	219,929					$ 88,728	226,966					$ 130,727	
71	**Total Revenues**						**$ 97,289**						**$ 141,021**	**45.0%**
73	**Monthly Use Per Customer (1)**									0			$ 152,214	Target
74	**Monthly $ per Customers @ Proposed Equalized ROR (2)**									$145.60				
76	**Total Commercial Customers**	**1,000**						**1,032**						
77	**Total Commerciall CCF**	**396,827**						**409,525**						
79	***TOTAL SYSTEM REVENUES***						***$ 984,378***						***$ 2,028,685***	***106.1%***
82													***$ 2,028,685***	**Target**

85 ***Notes:***
86 (1) Source for Use per Customer is Schedule GRP-5-G, page 3, line 23.
87 (2) Source for $/Month/Customer is Schedule GRP-5-G. page 4, line 27.

Exhibit G-8 - Impact of the Proposed Rate Change on Total Bill Revenues for the Twelve Months Ended September 30, 2025

PIKE COUNTY LIGHT AND POWER COMPANY

Present and Proposed Rates

Present SC1			Proposed SC1		
Customer Charge	$8.00		Customer Charge	$9.50	
Delivery Rate	$0.64660	/ CCF	Delivery Rate	$1.45930	/ CCF
Cost of Gas	$0.87297	/ CCF	Cost of Gas	$0.87297	/ CCF
All CCF @	$1.51957	/ CCF	**All CCF @**	$2.33227	/ CCF
Plus: State Tax Adjustment	0.0000%		Plus: State Tax Adjustment	0.0000%	
Plus: DSIC	$0.07767	/ CCF	Plus: DSIC	$0.00000	/ CCF
Minimum Charge:	$8.00	/ Month	Minimum Charge:	$9.50	/ Month

Present SC2			Proposed SC2		
Customer Charge	$12.23		Customer Charge	$14.25	
First 300 CCF			**First 300 CCF**		
Delivery Rate	$0.50890	/ CCF	Delivery Rate	$0.69380	/ CCF
Cost of Gas	$0.87297	/ CCF	Cost of Gas	$0.87297	/ CCF
First 300 CCF @	$1.38187	/ CCF	First 300 CCF @	$1.56677	/ CCF
Over 300 CCF			**Over 300 CCF**		
Delivery Rate	$0.35370	/ CCF	Delivery Rate	$0.52040	
Cost of Gas	$0.87297	/ CCF	Cost of Gas	$0.87297	
Over 300 CCF @	$1.22667	/ CCF	Over 300 CCF @	$1.39337	/ CCF
Plus: State Tax Adjustment	0.0000%		Plus: STAS	0.0000%	
Plus: DSIC	$0.07767	/ CCF	Plus: DSIC	$0.00000	/ CCF
Minimum Charge:	$12.23	/ Month	Minimum Charge:	$14.25	/ Month

PIKE COUNTY LIGHT AND POWER COMPANY

Monthly Bill Comparison
Reflecting Proposed Rate Increase With & Without Gas Costs

Monthly Usage (CCF)	Total Bill Monthly Bill @ Present Rate	Total Bill Monthly Bill @ Proposed Rate	Total Bill Change	Total Bill Percent Change	Delivery Only Monthly Bill @ Present Rate	Delivery Only Monthly Bill @ Proposed Rate	Delivery Only Change	Delivery Percent Change
Service Classification No. 1								
0	$8.00	$9.50	$1.50	18.8%	$8.00	$9.50	$1.50	18.8%
3	12.79	$16.50	3.71	29.0%	$10.17	$13.88	3.71	36.4%
10	23.97	$32.82	8.85	36.9%	$15.24	$24.09	8.85	58.1%
30	55.92	$79.47	23.55	42.1%	$29.73	$53.28	23.55	79.2%
50	87.86	$126.11	38.25	43.5%	$44.21	$82.47	38.25	86.5%
100	167.72	$242.73	75.00	44.7%	$80.43	$155.43	75.00	93.3%
200	327.45	$475.95	148.51	45.4%	$152.85	$301.36	148.51	97.2%
300	487.17	$709.18	222.01	45.6%	$225.28	$447.29	222.01	98.5%
400	646.90	$942.41	295.51	45.7%	$297.71	$593.22	295.51	99.3%
Service Classification No. 2								
0	$12.23	14.25	$2.02	16.5%	$12.23	$14.25	$2.02	16.5%
3	16.61	18.95	2.34	14.1%	$13.99	$16.33	2.34	16.7%
10	26.83	29.92	3.09	11.5%	$18.10	$21.19	3.09	17.1%
50	85.21	92.59	7.38	8.7%	$41.56	$48.94	7.38	17.8%
100	158.18	170.93	12.74	8.1%	$70.89	$83.63	12.74	18.0%
200	304.14	327.60	23.47	7.7%	$129.54	$153.01	23.47	18.1%
250	377.12	405.94	28.83	7.6%	$158.87	$187.70	28.83	18.1%
300	450.09	484.28	34.19	7.6%	$188.20	$222.39	34.19	18.2%
400	580.53	623.62	43.09	7.4%	$231.34	$274.43	43.09	18.6%
500	710.96	762.96	51.99	7.3%	$274.48	$326.47	51.99	18.9%
750	1,037.05	1,111.30	74.25	7.2%	$382.32	$456.57	74.25	19.4%
1,000	1,363.13	1,459.64	96.51	7.1%	$490.16	$586.67	96.51	19.7%
2,000	2,667.48	2,853.01	185.54	7.0%	$921.53	$1,107.07	185.54	20.1%
3,000	3,971.82	4,246.38	274.57	6.9%	$1,352.90	$1,627.47	274.57	20.3%
4,000	5,276.16	5,639.76	363.60	6.9%	$1,784.27	$2,147.87	363.60	20.4%

Included in the above bill calculations are:

	Present	Proposed
State Tax Adj	0.0000%	0.0000%
DSIC ($/Ccf)	$0.07767	$0.00000

PIKE COUNTY LIGHT AND POWER COMPANY

Statement of Revenues for the
Twelve Months Ending September 30, 2025
(At Current Rates)

Customer Classification	Delivery Revenue ($)	Gas Cost & DSIC Revenue ($)	Total Revenue ($)
SC1	850,044	1,061,467	1,911,511
SC2	174,801	389,312	564,114
Total	1,024,845	1,450,779	2,475,624

Note: Pike has other operating revenues of 3,775

Statement of Total Number of Customers
Served at September 30, 2025

SC1 Residential	1,334
SC2 Commercial	86
Total	1,420

PIKE COUNTY LIGHT AND POWER COMPANY

Tariff Regulations 52 Pa. Code § 53.52(b)(3) to (6)

53.52(b)(3) to (4) -- Statement of the number of gas customers whose bills will be increased and the annual increase in dollars (without gas costs).

Customer Classification	Customers @ 06/30/25	Annual Increase ($)
SC1 Residential	1,334	844,729
SC2 Commercial	86	40,577
Total	1,420	885,306

53.52(b)(5) to (6) -- Statement of the number of gas customers whose bills will be decreased and the annual decrease in dollars (without gas costs).

Customer Classification	Customers @ 06/30/25	Annual Decrease ($)
SC1 Residential	0	0
SC2 Commercial	0	0
Total	0	0

PIKE COUNTY LIGHT & POWER COMPANY

Rate Design Workpapers

Summary of Proposed Increases on Base Rates

	Sales	Delivery Charges	DSIC	Base Cost of Gas	Total
Revenue:					
Service Classification No. 1	1,116,578	$931,455	($86,726)	$0	$844,729
Service Classification No. 2	409,525	$72,385	($31,808)	$0	$40,577
Total	1,526,104	$1,003,840	($118,534)	$0	$885,306
Average Price per Ccf (cents per Ccf):					
Service Classification No. 1		83.420	-7.767	0.000	75.653
Service Classification No. 2		17.675	-7.767	0.000	9.908
Total		65.778	-7.767	0.000	58.011
Percentage Increases					
Service Classification No. 1					44.2%
Service Classification No. 2					7.2%
Total					35.8%

PIKE COUNTY LIGHT & POWER COMPANY

Rate Design Workpapers

Revenue Summary at Current Rates

	Sales	Delivery Charges	DSIC		Base Cost of Gas	Total
Revenue:						
Service Classification No. 1	1,116,578	$850,044	$86,726	0	974,741	$1,911,511
Service Classification No. 2	409,525	$174,801	$31,808	0	357,504	$564,114
Total	1,526,104	1,024,845	118,534	0	1,332,245	2,475,624
Average Price per Ccf (cents per Ccf):						
Service Classification No. 1		76.129	7.767	0.000	87.297	171.194
Service Classification No. 2		42.684	7.767	0.000	87.297	137.748

PIKE COUNTY LIGHT & POWER COMPANY

Rate Design Workpapers

Revenue Summary at Proposed Rates with Gas Costs

	Sales	Delivery Charges	DSIC		Base Cost of Gas	Total
Revenue:						
Service Classification No. 1	1,116,578	$1,781,499	$0	$0	$974,741	$2,756,240
Service Classification No. 2	409,525	$247,186	$0	$0	$357,504	$604,690
Total	1,526,104	$2,028,685	$0	$0	$1,332,245	$3,360,930
Average Price per Ccf (cents per Ccf):						
Service Classification No. 1		159.550	0.000	0.000	87.297	246.847
Service Classification No. 2		60.359	0.000	0.000	87.297	147.656

PIKE COUNTY LIGHT AND POWER COMPANY

Impact of Proposed Rate Change on Total Billed Revenue with Gas Costs
For the 12 Months Ending September 30, 2025

				Total Revenue at:		Increase:	
Service Class	Type of Service	Annual Bills	Total Sales (CCF)	Present Rates	Proposed Rates	Rev Change	Percent Change
1	Residential	16,008	1,116,578	$1,911,511	$2,756,240	$844,729	44.2%
2	Commercial	1,032	409,525	$564,114	$604,690	$40,577	7.2%
Total		17,040	1,526,104	$2,475,624	$3,360,930	$885,306	35.8%

PIKE COUNTY LIGHT AND POWER COMPANY

Impact of Proposed Rate Change on Delivery Billed Revenue without Gas Costs
For the 12 Months Ending September 30, 2025

				Del Revenue at:		Increase:	
Service Class	Type of Service	Annual Bills	Total Sales (CCF)	Present Rates	Proposed Rates	Rev Change	Percent Change
1	Residential	16,008	1,116,578	$850,044	$1,781,499	$931,455	109.6%
2	Commercial	1,032	409,525	$174,801	$247,186	$72,385	41.4%
Total		17,040	1,526,104	$1,024,845	$2,028,685	$1,003,840	98.0%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	DOCKET NO. R-2024-3052357
	:	
Pike County Light & Power Company (gas)	:	

Pike County Light and Power Company
Statement No. 2
Direct Testimony of
Accounting Panel

Chuck Lenns and Matthew Lenns

PIKE COUNTY LIGHT & POWER COMPANY
GAS RATE CASE
STATEMENT NO. 2
DIRECT TESTIMONY OF ACCOUNTING PANEL
CHUCK LENNS AND MATTHEW LENNS

Q. Would the witnesses please state your names and business addresses?

A. Charles Lenns, 330 West William Street, Corning, New York 14830. Matthew Lenns, 330 West William Street, Corning, New York 14830.

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

A. **(C.Lenns)** I am employed by Corning Energy Corporation ("CEC") where I hold the position of Senior Vice President and Chief Financial Officer.

(M.Lenns) I am employed by Corning Energy Corporation ("CEC") where I hold the position of Controller.

Q. Please explain the relationship between CEC and Pike County Light & Power Company ("Pike")

A. (C.Lenns) CEC is a New York State Holding Corporation and Pike is a wholly owned subsidiary of CEC.

Q. Please explain your educational background, work experience, and current general responsibilities.

A. **(C.Lenns)** I received my Accounting Degree from the University of Scranton, where I currently teach in the business school. I also hold a law degree from Duquesne University Law School, and I am a certified public accountant. Both of my professional licenses are in the

Commonwealth of Pennsylvania. I began my professional career in the tax practice of Ernst & Young, LLP ("EY"), and I served clients in the firm's power and utilities tax and M&A practice. I was a tax partner from 1989 until retiring from EY in 2012. From 2012 until 2018 I served as Vice President - Tax for Consolidated Edison Inc. ("CEI") until I reached the mandatory retirement age for Officers with that Corporation. I joined CEC as Vice President and Chief Financial Officer in July of 2020 for the parent and all of its subsidiaries, including Corning Natural Gas Corporation ("CNG") and Pike County Light and Power Company ("Pike" or "the Company").

(M.Lenns) I graduated from the University of Scranton in 2007 with a Bachelor of Science, having majored in accounting. After graduation from the University of Scranton in 2007, I joined PricewaterhouseCoopers LLP as an audit associate in their Technology, Information & Communication and Entertainment practice. I performed financial statement audits of clients primarily in publishing, healthcare and technology sectors. I joined Corning Energy Corporation in July

2022, and I oversee the financial reporting and monthly accounting close process for the Company.

Q. Have you previously submitted testimony before the Pennsylvania Public Utility Commission ("PAPUC")?

A. **(C. Lenns)** Yes.

(M. Lenns) No.

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

A. We will address the following topics:

- Discuss the major costs driving the gas rate increase Pike is seeking.

Q. Are you sponsoring any exhibits in this filing?

A. Yes. We are sponsoring Exhibits G-1 through G-5, which explain and detail the following:

- Historic financial data and Intercompany cost allocations between CNG and Pike(Exhibit G-1);
- Actual and forecast capital structures and rate of return (Exhibit G-2);
- Historic and forecast gas rate base (Exhibit G-3); and
- Historic and forecast cost of service (Exhibit G-4).

- Historic and forecast gas sales by service classification (Exhibit G-5).

COSTS DRIVING RATE INCREASE

Q. When were Pike's gas delivery rates last changed?

A. Pike has been operating under gas rates that went into effect on July 28, 2021.

Q. Please explain why Pike is seeking a gas base rate increase at this time.

A. As indicated above, the Company has been operating under rates that have been in place since 2021. Since that time Pike has invested significant amounts of capital to improve its infrastructure in order to increase reliability and modernize its gas system in order to better serve its customers. Assuming new rates go into effect in the fourth quarter of 2025; it will be over three years since Pike has had any rate relief. Overall sales for the last several years have remained fairly constant from the levels upon which rates were based, requiring the Company to absorb increases in operating costs.

Q. Was Pike's last base rate case fully litigated or settled?

A. Pike negotiated a settlement in its last rate case with PAPUC, the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate that was then approved by the Commission.

Q. How large a rate increase is Pike seeking?

A. Pike is seeking to increase its delivery rates by $905,900; representing an increase, as compared to rates established in the Company's 2021 gas rate order, of approximately 35.8 percent on total customer bills net of DSIC surcharge rolled into base rates.

Q. What is driving the rate increase the Company is seeking?

A. The increase of $905,900 can be attributed to the following:

- Change in Rate Base - $782,976
- Change in Return - 84,246
- Revenue Growth - (109,300)
- O&M Expenses - 194,000

• Depreciation & Amortization Expense	-	208,100
• Income Taxes and Other	-	(254,121)
Total Net Increase		$905,900

Q. The Company is requesting the aggregation of costs for customer credit card and debit card transactions, replacing individual fees to customers. Please give details about the updates with payment options and any changes the Company is recommending.

A. The Company is recommending that electronic payment fees charged by our third-party vendor become aggregated and included in the Company's cost of service. Customers can pay online, or through IVR with the payment vendor, using credit or debit cards, or checking or savings accounts. Other payment options have recently been added with the vendor, which include paying with PayPal, Venmo, Apple Pay, Amazon Pay, Google Pay, and through the Instant Payment Network (IPN) which includes Walmart Pay. With customer transaction fees aggregated, the Company can accept credit and debit payments in the office with the assistance of an encrypted swipe device. The Company has added features for customers to be notified of bill generation and due dates by SMS text message and PDF bill presentment by email. Customers have an option to pay by replying to the SMS message or email. Currently the fees are charged to, and paid by the customer who uses one of these electronic payment options at a cost of $2.64 per transaction. If a customer is paying through the IPN, there is no fee. If fees are aggregated, the Company will be able to negotiate a lower fee per transaction with the vendor. Customer fees would be $1.10 for a checking or savings account payment. All other payment options would have a fee of $2.04 per transaction, except for IPN payments, for which there is no fee. For the test year of October 1, 2023 through September 30, 2024, customers paid a total of $40,663.92 in electronic transaction fees. If the fees were aggregated, this total would have been $28,290.04, which reflects a customer cost savings of $12,373.88. Customers frequently complain about being charged a fee for paying their bills electronically. The Company is projecting an aggregated fee cost of $30,000 each rate year. The Company is anticipating additional customers opting to pay through the vendor if the fee is aggregated and as new features continue to be added. This cost is included in our revenue requirement in this rate case.

Q. What cybersecurity updates does the Company plan to undertake?

A. The next step in cybersecurity for the Company is Network Segmentation. Network Segmentation is the division of a computer network into smaller parts, separating Information Technology (IT) from Operational Technology (OT). Network Segmentation is crucial. IT and OT networks have different security needs. IT networks focus on protecting data confidentiality and integrity, while OT networks prioritize system availability and safety. Segregating these networks reduces the risk of a cybersecurity breach spreading from one to the other. IT and OT systems require different management and maintenance practices. When OT is integrated with IT networks, integration can lead to potential disruptions or inefficiencies in OT operations. By segregating IT and OT networks, the Company can more effectively manage risks, including minimizing the impact of potential incidents and ensuring that critical operational systems remain unaffected by issues occurring in the IT network. The Company was quoted a cost of $11,745.00 to complete the Network Segmentation by Micro-Solutions, one of the Company’s third-party IT vendors.

Q. Does the Company competitively bid its gas commodity purchase prices with gas suppliers?

A. No, Pike operates under a gas supply and gas transportation agreement with Orange & Rockland Utilities, Inc. (“O&R”). The Company purchases all of its gas from O&R on a “full services contract” basis, meaning that O&R is required to sell to Pike all of the natural gas that Pike needs to serve its customers. O&R delivers Pike’s purchased gas to Pike’s gate station in Port Jervis, New York.

Q. Is Pike able to purchase gas from other suppliers?

A. Currently, Pike cannot purchase gas from other suppliers because Pike is unable to transport gas over the O&R gas system. No other gas pipeline is available to Pike. However, Pike and O&R are currently negotiating an amendment to Pike's gas supply and transportation agreement with O&R that would allow Pike to purchase gas from gas marketing companies to be delivered to O&R's gate station in New York. O&R would then deliver the purchased gas to Pike's gate station in Port Jervis, New York.

Q. When Pike's contract with O&R is amended, will Pike have the ability to competitively bid its gas purchases from both O&R and from gas marketers?

A. Yes, Pike expects to negotiate a contract with O&R that would allow Pike to purchase gas either from O&R or from gas marketers. O&R will transport Pike's gas purchased from gas marketing companies to Pike's gate station in Port Jervis. The ability to competitively bid Pike's gas commodity cost should reduce its gas commodity price. The savings resulting from Pike's renegotiated contract will be passed on to Pike's gas customers. Pike will seek Commission approval for the amended contract in an appropriate future proceeding.

Q. Does Pike Gas propose to develop a Weather Normalization Adjustment ("WNA") in this rate case to apply to customer billings?

A. Yes.

Q. How are weather normalized gas volumes used to derive a gas utility's base rates?

A. Typically, as part of the rate design in a base rate proceeding, a utility's volumetric unit rates for gas service are derived by dividing the appropriate costs to be recovered through volumetric based rates by the anticipated weather-normalized gas sales volumes. This calculation produces rates that are designed. These rates are designed to provide the utility with an opportunity to recover the costs it incurs to provide utility service, at the levels determined in the utility's rate case under normal weather conditions. To the extent any costs are subject to recovery in a volumetric charge, the recovery of such amounts is entirely dependent upon the volumes of gas usage experienced by the utility. Therefore, the recovery of costs in a volumetric component of rates will almost always lead to a difference in recovery of actual costs because actual weather conditions will by and large never match the normalized weather conditions used to set rates.

Q. Please explain how weather influences the recovery of costs for a gas utility and costs to customers.

A. As a result of the volumetric rates described above, if actual temperatures are normal, the utility has a reasonable opportunity to fully recover its fixed costs of service at established sales levels, as reflected in the calculation described above, and the customers' payment for service reflects the costs of the utility. Unfortunately, normal temperatures seldom, if ever, occur. Therefore, because of abnormal weather and a rate design that is based, in substantial part, on customer usage, the amount of distribution revenue collected from customers can vary widely from the revenue requirement level authorized by the regulator. In the case of warmer weather, the utility may under recover its costs and need to pursue cost management efforts that help stabilize and support the overall financial health and performance of the company. In the case of colder weather, customers experience higher bill cost burdens which may negatively impact customer abilities to manage utility costs.

Q. Please explain how fluctuations in weather over time impact a gas utility’s temperature-sensitive customers and the utility’s financial performance.

A. Since the bills of gas customers are largely based on the level of gas usage, temperature-sensitive customers’ monthly bills can vary widely due to changing weather conditions. Under traditional ratemaking methods, if actual temperatures were colder than normal, the typical gas customer would use more gas, pay more for service (through volumetric charges), and potentially overpay its share of fixed costs. This occurs because the unit rates used to recover fixed costs are not reduced to recognize the higher gas volumes used by customers during colder weather. Since the gas utility’s level of fixed costs does not change, the higher gas volumes applied against the same unit rate would generate comparatively higher distribution revenues than the level of fixed costs established for ratemaking purposes. Conversely, in warmer than normal weather, the reverse situation would occur. Customers’ gas usage decreases with warmer temperatures, thus generating comparatively lower distribution revenues than required to recover the gas utility's total fixed costs that do not decrease due to warm weather.

Q. Please define and describe the concept of a WNA mechanism.

A. The utility's distribution rates, which are established to allow the utility to recover its authorized level of distribution revenues, are based on expected throughput during normal weather. When actual weather deviates from normal weather, there will be a difference between actual and projected distribution revenues. A WNA mechanism adjusts a customer's bill due to these variations from normal weather (i.e., temperature variations or heating degree day variations) in order to have the bill reflect normal weather conditions. For billing periods that are colder than normal, a credit will be applied to the bill. For billing periods that are warmer than normal, a surcharge is applied to the bill. WNA mechanisms are typically effective for usage during the heating season calendar months (e.g., October through May). WNAs reduce the amount of variation in both customer bills and utility revenues by making a compensating adjustment for the difference between actual weather and normal weather.

Q. Do WNA mechanisms differ in their design?

A. Yes. Gas utilities typically use two types of WNA mechanisms: (1) a mechanism that adjusts current billings on a monthly billing basis as the bill is being calculated and issued; and (2) a mechanism that adjusts billings on a lagged basis where the adjustment appears on the customer's bill(s) from a few to several months after a variation from normal weather is experienced.

Q. Which type of WNA mechanism is the Company proposing to implement?

A. The Company proposes to implement a WNA mechanism that adjusts billings on a monthly billing basis as the bill is being calculated and issued.

Q. Does the Company propose to apply weather normalization to all customer bills?

A. No. The Company seeks to apply a WNA adjustment only to residential customer monthly bills. Other customers are generally better able to manage fluctuations in monthly bills caused by variations from normal weather than our residential customers.

Q. For what months of the year does the Company propose to apply a WNA adjustment to residential customer bills?

A. The Company proposes to apply a WNA adjustment to residential customer bills issued for the months of October through May, since these months are most likely to produce large variations from normal weather.

EXHIBIT G-1 HISTORICAL FINANCIAL DATA

Q. Please describe Exhibit G-1.

A. Exhibit G-1 contains the historic financial data for Pike as required by PAPUC regulations. Schedule 1 shows the balance sheets of Pike at September 30, 2024 and September 30, 2023. Schedule 2 provides the account balances comprising the Company's net investment in electric, gas and common utility plant in service at September 30, 2024. Schedule 3 is an income statement that shows the derivation of net income for gas and gas operations for the year ended September 30, 2024. Schedule 4 is a comparative income statement for Pike's gas operations for the twelve months ended September 30, 2024 and September 30, 2023. Schedule 5 shows the intercompany charges billed to Pike under the terms of the intercompany agreement with CNG for the twelve months ended September 30, 2024. Schedule 6 shows the intercompany cost allocation factors currently in effect. Schedule 7 show the activity impacting the Intercompany Payable between Pike and Corning Natural Gas Corporation ("CNG"), also a wholly owned subsidiary of CEC, between September 30, 2023 and September 30, 2024. These charges and credits are in accordance with the terms of the intercompany agreement between Pike and CNG.

INTERCOMPANY COST ALLOCATIONS

Q. Are you familiar with Pike's books and records, as well as the intercompany cost allocations between Pike

and CNG, pursuant to which certain Administrative and General costs, including but not limited to, wages, shared services and taxes, are allocated to Pike?

A. Yes.

Q. Are the accounts of the Company kept in accordance with the Uniform System of Accounts as prescribed by the PAPUC?

A. Yes.

Q. Please describe Exhibit G-1, Schedule 5 in more detail.

A. Exhibit G-1, Schedule 5, "Statement of Charges Made by Corning Natural Gas Corporation to Pike County Light & Power Company's Gas Operations" is submitted in support of the charges for gas operations billed by CNG to Pike. The schedule sets forth by prime account each item for which a direct charge is made or which was the result of an allocation.

Q. What types of services are billed by CNG to Pike based on direct charges?

A. As part of the approval process for the acquisition of Pike by CNG, the New York State Public Service Commission (NYPSC) and PAPUC have required CNG to bill

Pike on a direct charge basis for services rendered by CNG whenever it is practical, based on payroll records, direct payments to vendors and contractors, and usage studies supporting the distribution of clearing accounts. Further CNG is required to develop and update Cost Allocation factors annually for shared expenses. The factors that are currently in effect are shown on Schedule 6 of Exhibit G-1. The direct and allocated charge billings are for activities and services rendered that are for the exclusive benefit of Pike's customers, and are primarily shared administrative costs such as customer billing and collection, processing of invoices, administration of benefit plans, Accounting, Tax and Financing functions, Information Technology and Computer Services.

Q. Please describe the types of costs allocated by CNG to Pike and the methods of allocation used.

A. The types of costs allocated and the basis for such allocations are shown on Schedule 6 of Exhibit G-1. Costs that are impractical to charge on a direct basis are allocated to Pike based on the relationship in accordance with our affiliate interest agreement for the type of expense of Pike to the total expenses incurred by CNG and its utility subsidiaries. The schedules contain the percent of shared costs allocated to expense or capital projects, depending on the nature of the service.

With regard to Federal income taxes, CEC and its subsidiaries file a consolidated Federal Income Tax return with its new parent company, ACP Crotona Holdings, LP, and any tax liability or benefit is allocated among CEC and its subsidiaries as provided for in Treasury Reg. Section 1.1502-33. Tax liabilities or benefits are computed and allocated to each company on the separate return basis, with tax liabilities or benefits allocated to the company that generated the liability or benefit, and each member corporation’s tax liability generally does not exceed its separate return liability.

Q. How does Pike allocate common costs between electric and gas operations?

A. Pike allocates 85 percent of common costs to electric operations and 15 percent to gas operations. The allocation is based on the ratio that net plant for each service bears to total net electric and gas plant.

EXHIBIT G-2 CAPITALIZATION

Q. Please describe Exhibit G-2.

A. Exhibit G-2 shows the actual and forecast capital structures.

Q. What capital structure is Pike requesting in this proceeding?

A. The Company is requesting a capital structure at September 30, 2025 as shown below:

	Ratio
Long-Term Debt	40.72%
Short-Term Debt	8.64%
Common Equity	50.63%
Total	100.00%

Q. Do you believe that this is a reasonable capital structure to be employed in this proceeding?

A. Yes, we do.

Q. Please explain why this capital structure is appropriate?

A. It reflects the forecasted ratios of capital being employed by Pike, as set forth on Exhibit G-2, Schedule 1 for the twelve months ending September 30, 2025. The capital structure reflects the proportions of the actual capital being used in the utility's business plus a projected debt financing. We would note that Exhibit G-2, Schedule 2, page 2 of 2 includes new refinanced long-term debt that Pike issued on September 12 of 2024 with its parent entity CEC, in the amount of $17.584 million at a coupon rate of 6.31%. The average daily short-term debt balance for the Twelve Months Ended September 30, 2024 of $2,006,792 was reflected in the Capital Structure as of September 30, 2025 as a proxy for the average short-term debt balance at September 30, 2024, and adjusted for our anticipated level of spend over the next year. The current cost of short-term debt of 7.58% was used in calculating the cost of this debt. This capital structure is reasonable when compared to the capital structure of other companies and weighted to a 50/50 split between debt and equity.

Q. What is your conclusion as to the reasonableness of Pike's requested common equity ratio in this proceeding?

A. Based on the above discussion, we conclude that the 50.63 percent common equity ratio requested by Pike in this proceeding is reasonable. The equity ratio reflects Pike's forecast of net earnings during the Twelve Months Ended September 30, 2025 and thus is appropriate to use in this proceeding.

Q. What cost of equity return is the Company requesting in this proceeding?

A. As shown on Exhibit G-2, Schedule 3, the cost of equity return is 10.20 percent. For revenue requirement purposes, we rounded the return on equity from the Gas Distribution System Improvement Charge (DSIC) Eligible Utilities Return on Equity Summary, as published for September 18, 2024. The Company is willing to accept the generic ROE return made by the commission in order to minimize rate case costs to its customers.

Q. What overall rate of return ("ROR") is the Company requesting in this proceeding?

A. As shown on Exhibit G-2, Schedule 3, the overall ROR is 8.59 percent.

Exhibit G-3 GAS RATE BASE

Q. Please describe Exhibit G-3.

A. Exhibit G-3 consists of a summary and eleven schedules containing Pike's historic and future gas rate base. Schedules 10 and 11 are discussed by Company Witness Verbraak.

Q. Please describe the method used to calculate the historic gas rate base at September 30, 2024 as shown on the summary page.

A. We began with actual gas utility plant and plant reserves to arrive at net plant at September 30, 2024. To net plant, we added cash working capital, materials and supplies, prepayments, and deferred debits. Finally, we deducted deferred credits, accumulated deferred income taxes, and customer deposits to arrive at gas rate base.

Q. Please describe the method used to calculate the forecast gas plant balance at March 31, 2025.

A. We began with the actual gas plant in service balance per books at September 30, 2024. The completed construction work in progress ("CWIP") projects were transferred to plant as shown on Exhibit G-3, Schedule 1, pages 1 and 4. We would note that because of Pike's small size and the effort required to summarize the CWIP projects, they are normally transferred to plant-in service at the end of its fiscal year (i.e., December 31st). Company Witness Verbraak provided us with the budgeted gas distribution expenditures and additions scheduled for October 1, 2024 through March 31, 2026 (18 month lookforward) shown on Exhibit G-3, Schedules 10 and 11. Retirements were projected through March 31, 2026. For distribution plant retirements were based on historic levels. Common general plant, other than computer software, is amortized over five years. As a result, assets placed in service during 2020 – 2021, will be retired in 2025 – 2026. The calculated adjustment for distribution plant of $4,020,642 is shown on Exhibit G-3, Schedule

1, page 1 of 4. The adjustment for common general plant allocated to gas of $68,100 is shown on Exhibit G-3, Schedule 1, page 2 of 4.

Q. What is the purpose of Exhibit G-3, Schedule 1, page 3 of 4?

A. Exhibit G-3, Schedule 1, page 3 of 4 is necessary to allocate shared net plant related to administrative offices, equipment, and computers used by CNG employees that provide services to Pike. Office space was allocated on the basis of square footage utilized by those employees (i.e., 0.68%). Furniture, equipment, and computers were also allocated on that basis.

Q. What is the purpose of Exhibit G-3, Schedule 1, page 4 of 4?

A. As discussed above Exhibit G-3, Schedule 1, page 4 of 4 is necessary to reclassify completed plant additions from construction work in progress to plant in service. The offset is shown in Exhibit G-3, Schedule 1, page 1 of 4.

Q. Please describe the calculation of the accumulated provision for depreciation of gas plant in service for the period ending March 31, 2026.

A. We began with the per books balance at September 30, 2024, added accruals projected for the 18 months ending March 31, 2026 and subtracted projected retirements for the same period to arrive at the ending balance at March 31, 2026. Our calculated adjustment of $185,400 for the gas plant reserve is shown on Exhibit G-3, Schedule 2, page 1 of 2.

Q. Please describe the calculation of the accumulated provision for depreciation of common plant in service for the period ending March 31, 2026.

A. We began with the per books balance at September 30, 2024 and added accruals projected through March 31, 2026 and subtracted projected retirements for the same period to arrive at the ending balance at March 31, 2026. The calculated adjustment of $(900) is shown on Exhibit G-3, Schedule 2, Page 2.

Q. How did you calculate the cash working capital for the twelve months ending September 30, 2024 and 2025?

A. We prepared a lead/lag study. The results of the study are shown on Exhibit G-3, Schedule 3 pages 1 and 2.

Q. Please provide an overview of the lead/lag study and describe its results.

A. The lead/lag study utilizes accounting information and financial studies for the twelve months ended September 30, 2024 to determine the net lag days. The net lag days are applied to the cost of service inputs for the years ending September 30, 2025, in order to determine the cash working capital requirements reflected in rate base. The study indicates a cash working capital requirement of $118,831 for the twelve months ended September 30, 2025 as shown on Exhibit G-3, Schedule 3, page 2 of 2. We would note that the working capital requirement for the Twelve Months Ended September 30, 2024 is shown on Exhibit G-3, Schedule 3, page 1 of 2. The purpose of the cash working capital component of rate base is to compensate the Company for funds it provides to pay operating expenses in advance of receipt of revenue. It reflects the amount of capital over and above investment in plant and other separately identified rate base items provided by the Company to bridge the gap between the time the Company provides service and the time the Company collects revenue for that service. A lead or lag reflects the amount of time that elapses between when a utility provides a product or service, and when that providing utility is compensated for the product or service provided. For the purpose of this study, the amount of lead or lag times was calculated in days. We note that the while the study period was a leap year (i.e., contained 366 days), we reflected 365 days in our calculations, since the twelve months ended September 30, 2025 has 365 days.

Q. Please describe the revenue component of the lead/lag study.

A. The lag on revenue collection consists of three components:

- the time between rendering of service and meter reading;
- the time between meter reading and billing of services; and

- The time between billing of services and collection of revenue.

Pike's customers are billed on a monthly cycle. The average time from the rendering of service to customer payment is calculated to be a normal average of 17.49 days. We then did a weighted average calculation in buckets of 1-10 days, 11-20 days and over 20 days. Using this weighted average approach we calculated that approximately 62 percent of our customers pay within 1-20 days, however some of our larger customers pay in more than 20 days. Using total balances in those buckets we calculated a weighted average of 21.3 days.

Q. Please describe the treatment of cost of service in the study.

A. The cost of service was broken down into the basic components of operating expense and operating income. Operating income, which represents a return on invested capital, is included as a component of the cost of service.

Q. Please describe the treatment of purchased power expenses in the study.

A. The cost of purchased gas and related expenses are billed monthly and are required to be paid within 10 days of receiving the invoice. Invoices are normally received within the first few days following the service month. As such we used 10 days.

Q. Please describe the treatment of salaries and wages.

A. The lag for salaries and wages was calculated to be 8 days. All employees are paid Bi-Weekly on the Thursday following the weeks worked (service period 14 days) / 2 = 7 day midpoint. We utilized 8 days for salaries as a result.

Q. Please describe the lag days associated with pensions.

A. The Company sponsors a 401K plan that includes a partial match of employee contributions. The match is paid at the same time as payroll, so the 8 day lag was assigned to fund contributions.

Q. Please describe the lags associated with employee welfare expenses.

A. Employee welfare premiums for health, life and Workers' Compensation insurance are administered by CNG. Pike reimburses CNG once per reporting month. We utilized 30 days for intercompany charges for the month close procedures, and 23 days for employee welfare charges based on the calculated timing of payments made during the test period ended September 30, 2024.

Q. How was the lag for intercompany payments calculated?

A. As with employee welfare expenses discussed above, the lag is measured as once per month per cycle close period, or 30 days.

Q. Please describe the lag associated with uncollectible accounts expense.

A. Uncollectible accounts expense was lagged at 8 days, due to the fact that our uncollectible balance for the year ended September 30, 2024 is consistently low ($43,714) with the revenue collections on $15.5 million on total operating revenues for gas and electric for the period ended September 30, 2024.

Q. Please describe the lag associated with other Operation and Maintenance ("O&M") expenses.

A. The lag on other O&M expenses was calculated to be 23 days. This calculation is based on an analysis of accounts payable payments made to vendors for materials and services charged to O&M expense. Lag days were measured from the mid-point of the month (365 days / 12 / 2 = 15.2) to the date of payment for services (8.0 days), totals 23.2 days.

Q. Please describe the lead or lag associated with taxes other than income taxes.

A. FICA payroll taxes are funded at the same time as payroll and assigned the same 11.0 day lag. Pennsylvania property taxes are amortizations of prepaid costs and were assigned zero lag days. The average unamortized prepaid balance for property taxes is shown and included in Rate Base on Exhibit G-3, Schedule 5. If the prepaid balances are eliminated from Rate Base it will be necessary to adjust the Lead Lag Study to include the (lead) / lag times for prepaid expenses.

Q. Please describe the lag days associated with Federal and state income taxes.

A. The Federal Income Tax ("FIT") and state income tax lag assumes four annual payments (i.e., September 15th, December 15th, April 15th, and June 15th). We determined that there was a lag of 30 days by the number of days that elapsed from the service period to payment within 30 days.

Q. Please describe the lag days associated with the amortization of deferred expenses, deferred federal and state income taxes, depreciation, and return on invested capital.

A. These components were assigned zero lag days because they are non-cash items.

Q. How did you calculate the Plant Materials and Stores component of gas working capital?

A. We used the average balance for the twelve months ended November 30, 2024 as a proxy for the plant material balances for the twelve-month period ended September 30, 2025. The calculation is shown on Exhibit G-3, Schedule 4.

Q. How did you calculate the prepayments component of gas working capital?

A. We used the same method we used to calculate the plant material balances. The components of prepayments and the balances used for the calculations are shown on Exhibit G-3, Schedule 5.

Q. Please describe Exhibit G-3, Schedule 6.

A. Schedule 6 contains the forecast deferred rate case cost that is included in rate base. The Company estimates that it will incur $250,000 of outside legal and consulting costs related to the electric and gas rate filings. $37,500 of these costs was allocated to gas operations based on a net plant split. On Schedule 6, we calculated the after-tax amount for this item to be approximately $27,100.

Q. Please describe Exhibit G-3, Schedule 7.

A. At September 30, 2024, the Company had a negative deferred credit balance of $6,029 related to timing differences created by the Federal Tax Cuts and Jobs Act (TCJA) that will turn around in the future. The net of Tax balance for this item is forecast to be $6,000 at September 30, 2025 and is reflected as a rate base addition in Exhibit G-3, Summary.

Q. Please describe the calculation of customer deposits as shown on G-3 Schedule 8.

A. We used the average balance for the twelve months ending November 30, 2024 as a proxy for the twelve-month period ending September 30, 2025.

Q. Did you calculate the deferred income taxes for the twelve months ending September 30, 2025?

A. Yes. This calculation, shown on Exhibit G-3, Schedule 9, presents the difference between the balances of accumulated deferred income taxes at September 30, 2024 and September 30, 2025, respectively.

EXHIBIT G-4 GAS COST OF SERVICE

Q. Please describe Exhibit G-4.

A. Exhibit G-4 consists of a summary and ten schedules containing the historic and future gas cost of service. The Accounting Panel supports all schedules. Page 1 of the Summary shows the historic and forecast cost of service, page 2 of the Summary shows the calculation of the revenue requirement, and page 3 of the Summary lists all of the adjustments to the cost of service.

Q. How did you develop the historical and forecast cost of service?

A. We began with the actual per books information for the twelve months ended September 30, 2024. This information is shown in Column 1 of Exhibit G-4, Summary, Page 1 of 3. Column 3 sets forth the adjustments necessary to bring historical revenues, expenses, and rate base in line with the levels of revenues, expenses and rate base projected for the twelve months ending September 30, 2025.

Q. Please describe how the revenue requirement of $905,900 shown on page 2 of the Summary was calculated?

A. We began with the projected September 30, 2025 rate base from Exhibit G-3, Summary. To this balance we applied the overall rate of return shown on Exhibit G-2, Schedule 3. This produced a return of $917,330. We compared this number to the earned return projected on page 1, column 4 of the Summary, which was $260,700. The difference between these two amounts is $656,630, which we factored up for customer uncollectibles and income taxes to arrive at a revenue requirement of $905,892 or $905,900 rounded.

Q. Please describe Exhibit G-4, Schedule 1, Page 1 of 2.

A. Exhibit G-4, Schedule 1, Page 1 of 2 compares the forecast billed gas sales and revenues for the Twelve Months Ended September 30, 2025 to the actual gas sales and revenues for the Twelve Months Ended September 30, 2024. The calculation of the forecast delivery revenues and gas cost recoveries for the Twelve Months Ended June 30, 2025 come from Exhibit G-5, Schedule 6.

Q. Please continue with page 2 of Schedule 1.

A. Exhibit G-3 Schedule 1, page 2 of 2 shows Other Operating Revenues for the Twelve Months Ended September 30, 2024 and 2025. The forecast of Late Payment Charge ("LPC") revenues was calculated by taking the ratio of actual LPC revenues to total billed gas revenues for the twenty-four months ended September 30, 2024. This resulted in a LPC factor of 0.17%, which was multiplied by the forecast of gas revenues shown on Page 2 of Schedule 1 to project LPC revenues of $3,775.

Q. Please describe Exhibit G-4, Schedule 2.

A. Exhibit G-4, Schedule 2 reflects the change in purchased gas costs and matches projected gas cost recoveries through the GCR for the Twelve Months Ended September 30, 2025.

Q. Please explain the increases in salaries shown in Exhibit G-4, Schedule 3.

A. Page 1 of Exhibit G-4, Schedule 3 contains the calculation of the annual wage increases. We took both direct and allocated payroll that was charged to Pike's gas operations and first removed the May 2024 increase in order to determine base wages before the increase that went into effect during the twelve months Ended September 30, 2024. We then annualized the May 2024 wage increase by multiplying the base salaries before the increase by 58.33% of 4.0%, representing the seven months beyond the historic test year, representing the increase that will go into effect during October 2024 – April 2025. We next applied the estimated annual overall increase of 4.0% that will go into effect in October 2025 to the actual payroll for the Twelve Months Ended September 30, 2024 plus the annualized increase. This Schedule will be updated for the actual overall wage increase percentage when the Company files an update.

Q. What is the basis for the wage increase factor of 4.0 percent?

A. The Company's overall general wage increase guidelines were set at 4.0 percent. While some employees may receive more than a 4.0 percent increase due to promotions and changes in responsibilities, others may receive less. There is always a small level of employee turnover in the mix of salaries, due to retirements and employees leaving for other reasons. In some cases the salary for the replacement is at a lower wage rate and sometimes they are at a higher one than the current incumbent. The Company tries to keep the overall level of increases in wages to be no more than 4.0 percent.

Q. Please continue.

A. Page 2 of Exhibit G-4, Schedule 3 reflects the cost of two new positions to be added during the Twelve Months Ended September 30, 2025. Both positions would be full time Pike employees. The first position is for an Assistant General Manager, and this person to be hired will perform multi-functions; including project budgeting, materials management and procurement, analyzing actual results vs. budget on a monthly basis, oversee customer service, and will report to corporate management on a regular basis. 14.3 percent of the expense portion of the salary for this position

($20,000) was allocated to Pike's gas operations based on the current gas vs. electric customer split. $50,000 will be allocated to Pike Electric expense, and the remaining $70,000 will be allocated to capital between electric and gas at the 85/15 split. The second position is an electric Systems Planner, which will be allocated 100% to Pike Electric.

Q. Please continue with a description of Adjustment No. (4), Changes in Operation and Maintenance Expense to Reflect the Estimated Increase in Payroll Ancillary Costs and Adjustment No. (9), Changes in Taxes Other Than Income Taxes to Reflect Increases in Payroll Taxes, as shown on Exhibit G-4, Summary, as well as on Exhibit G-4, Schedule 4 and Schedule 9, Page 1, respectively.

A. The estimated increase in payroll ancillary costs, which amounts to $13,500, was calculated by applying a fringe benefit rate of 36.05% to the forecasted wage increase amounts, shown on Exhibit G-4, Schedule 4. The 36.05% fringe benefit rate includes the cost of health and life insurance at 22.02%, Workers' Compensation insurance at 11.49%, and Pike's 401K matching contribution of 2.54%. These rates were developed based on the historic cost of each benefit item in relation to the total historic labor costs for the twelve months ended September 30, 2024. The estimated Payroll Taxes of $23,839 was calculated by applying the payroll tax rate of 7.65% to the forecasted wages shown on Exhibit G-4, Schedule 9, page 2 of 2. The $23,839 represents an increase of $3,106 from the historical level shown on Exhibit G-4, Schedule 9, page 1 of 2. The 7.65% payroll tax rate includes the cost of Federal Insurance Contribution Act Tax at 6.20% (capped at $168,600 of annual salary per employee) and Medicare at 1.45%. These tax rates are based on the current statutory rates.

Q. Please describe Adjustment No. (5), Changes in Operation and Maintenance Expense to reflect the amortization of estimated rate case expenses, as shown on Exhibit G-4, Schedule 5.

A. Adjustment No. (5) Represents an increase in O&M expense of $9,400 to reflect a four-year amortization of estimated incremental costs associated with this rate case. As shown on Schedule 5, Pike estimates that it will incur $37,500 of costs in the preparation and filing of this case, which are primarily for consultant fees to prepare the exhibits and testimony in support of the revenue requirement, cost service study, rate design, and outside legal fees.

Q. Please describe Adjustment No. (6), for intercompany administrative and operating charges, as shown on Exhibit G-4, Summary, as well as on Exhibit G-4, Schedule 6.

A. This adjustment reflects the test year level of intercompany charges not reflected in other schedules of $780,177, (e.g., payroll, taxes other, etc.). To this amount we applied the current Consumer Price Index of 1.0% to escalate these costs for the Twelve Months Ended September 30, 2025. This adjustment increases O&M expense by $7,802 which was rounded to $7,800.

Q. Please address Adjustment No. (7), as shown in G-4, Schedule 7.

A. Adjustment No. (7) adjusts the uncollectible expense recorded on the Company's books to reflect the actual net bad debt write-offs experienced during the twenty-four months ended September 30, 2024. We took the actual net write-offs (i.e., customer bills written off as uncollectible less recoveries), as a percentage of billed revenues during the same period of time. This produced a factor of 0.28 percent. This percentage was applied to the projected revenues for the twelve months ended September 30, 2025 to calculate the annual bad debt expense of $6,322. This expense was compared to the uncollectible accruals recorded during the twelve months ended September 30, 2024, which was a positive expense of $14,475 to arrive at the adjustment of $8,153 or $8,200 rounded.

Q. Please explain Adjustment (8) to depreciation expense.

A. Exhibit G-4, Schedule 8 consists of four pages. The first page shows the calculation of depreciation expense for the rate year, the Twelve Months Ended September 30, 2025. Page 2 shows the calculation of the composite book depreciation rate for gas distribution and general plant that was utilized on page 1 of this Exhibit. Page 3 shows the calculation of the average amortization rate for common general plant that was reflected page 1 of this Exhibit.

Finally, page 4 shows the current allowance for net salvage and the amortization of an unallocated reserve established in Case R-2020-3022134.

Q. Please explain how the adjustment to depreciation expense shown on page 1 of Schedule 8 was calculated.

A. We started with the gas distribution and common general plant balances allocated to gas at September 30, 2024. To these balances we eliminated non-depreciable plant. We then reflected the plant additions and retirement as shown on Exhibit G-3, Schedule 1, pages 1 and 2 to calculate the plant balance subject to depreciation at September 30, 2025. The plant balances were then multiplied by the composite depreciation rates from pages 2 and 3 to calculate the rate year level of depreciation expense of $333,062. This level was compared to the Test Year level of $208,161 and resulted in the depreciation adjustment of $124,902 which was rounded to $124,900.

Q. What is the purpose of the depreciation reserve calculations shown at the bottom of page 1 of Exhibit G-4, Schedule 8?

A. The calculated increases in the depreciation reserve are reflected in Rate Base Exhibit G-3, Schedule 2, pages 1 and 2.

Q, Are the depreciation, amortization, net salvage rates shown on pages 2 through 4 the same as contained in the Settlement Agreement approved by the PAPUC in Case R-2020-3022134?

A. Yes, with the exception of some general plant accounts that did not exist at the time of the Agreement.

Q. With regards to the current allowance for removal and net salvage shown Exhibit G-4, Schedule 8 on page 4, why hasn't the Company proposed any changes to the current allowances?

A. Pike has not proposed any changes to the current allowances for removal and net salvage because we do not have adequate historic data to recommend changes at this time. The current allowance of $29,409 is shown on Exhibit G-4, Schedule 8, Page 4.

Q. Please discuss the recovery of net salvage.

A. In lieu of recovering net salvage costs through the annual depreciation rate, the PAPUC establishes an annual allowance to be collected from, or returned to, customers through base rates which is computed by averaging the Company's annual actual expenditures for net salvage costs. That amount is then added to or subtracted from annual depreciation expense.

Q. Please explain the amortization of the reserve deficiency of $900, shown on the bottom of Exhibit G-4, Schedule 8, Page 4.

A. As a result of a previous gas base rate case (Docket No. R-2008-2046520), the Company moved the deficiency in the depreciation reserve out of the allocated portion of the reserve, which maintains a reserve for each plant account to an unallocated account. The Company is in the process of collecting that deficiency from customers.

Q. Are you proposing any changes to the unallocated reserve and its associated amortization to collect that money from customers?

A. No, we are not.

Q. Please describe Adjustment No. (9), Changes in Taxes Other, as shown Exhibit G-4, Schedule 9, Page 1.

A. Adjustment No. (9), in addition to the change to payroll taxes discussed above, reflects the change in payroll and property taxes for the Twelve Months Ending September 30, 2025. Property tax expense was based on the latest actual tax bills.

Q. Please describe Adjustment No. (10), Calculation of Income Tax Expense for the Twelve Months Ending September 30, 2025, as shown Exhibit G-4, Schedule 10.

A. Adjustment No. (10) shows the necessary additions and subtractions that must be made to operating income before taxes in order to determine taxable income to which the statutory tax rates are applied.

Q. Please explain page 3 of Schedule 10.

A. Page 3 shows the calculation of the interest deduction included in page 1 of Schedule 10. The weighted cost of debt of 7.21 percent comes from Exhibit G-2, Schedule 3 after combining the weighted interest cost for both long and short term debt and is multiplied by Pike’s rate base to determine the interest deduction reflected on pages 1 and 2 of this Exhibit.

EXHIBIT G-5 GAS SALES AND REVENUES

Q. What were Pike's actual total delivery volumes for the 12 months ended September 30, 2024?

A. Pike's actual total delivery volumes for the 12 Months Ended September 30, 2024 were 1,312,666 CCFs as shown on Exhibit G-5, Schedules 1 and 5. The associated actual monthly billed revenues for the 12 Months Ended September 30, 2024, are shown on Exhibit G-5, Schedule 3.

Q. Please summarize, in aggregate form, your delivery volume forecasts for the 12 months ending September 30, 2025.

A. For the 12 months ending September 30, 2025, the total delivery volume forecast is 1,526,104 CCFs, which is an increase of 213,438 CCFs from the 12 months ended September 30, 2024 and reflects a 16.2 percent growth for the period. The calculation of the forecast sales is shown on Exhibit G-5, Schedule 5.

Q. How did you project the Company's gas billed delivery volumes?

A. As shown on Exhibit G-5, Schedule 5, we started with the actual delivery volumes for the Twelve months ended September 30, 2024. To this level we added 154,703 CCFs in order to weather normalize the historic level of sales. To this level of sales we made an additional adjustment to reflect forecasted growth in residential and commercial customers of an additional 58,743 CCFs. The projected growth in residential and commercial customers was based on the actual growth between the Twelve Months Ended September 30, 2023 and September 30, 2024.

Q. Please explain how you estimated Pike's gas revenues for the forecast period.

A. The projected gas revenues are shown on Exhibit G-5, Schedule 6 and are based on our 2025 forecasted year.

Q. Does that conclude your testimony?

A. Yes, it does. We reserve the right to update or amend this testimony.

Pike County Light and Power Company **Exhibit G-1**

Index of Schedules

Balance Sheet and Supporting Schedules, Income Statement,

and Joint Operating Agreement Charges for the Test Year

Pike County Light and Power Company
Balance Sheet
As of September 30, 2024 and 2023

	September 30 2024	September 30 2023
ASSETS AND OTHER DEBITS		
Utility Plant		
Electric Plant in Service	$ 34,737,197	$ 26,195,778
Gas Plant in Service	7,193,512	6,182,000
Common Plant in Service	1,463,869	1,700,322
Construction Work in Progress	3,020,281	5,777,071
Total Utility Plant	46,414,860	39,855,171
Accumulated Provision for Depreciation		
Electric	4,247,701	3,402,324
Gas	569,683	418,338
Common	1,328,583	1,038,894
Total Accumulated Provision for Depreciation	6,145,966	4,859,557
Net Utility Plant	40,268,894	34,995,614
Other Property and Investments		
Nonutility Property	-	-
Accumulated Provision for Depreciation	-	-
Net Other Plant	-	-
Current and Accrued Assets		
Cash	820,047	395,466
Customer Accounts Receivable	1,727,192	1,568,338
Other Accounts Receivable	(24,235)	(76,788)
Accumulated Provision for Uncollectible Accounts	(43,714)	12,510
Accounts Receivable from Associated Companies	154,076	82,021
Materials and Supplies	1,893,323	2,934,718
Prepayments	(96,386)	(680,976)
Total Current and Accrued Assets	4,430,302	4,235,288
Deferred Debits		
Unamortized Debt Expense	632,375	78,178
Other Regulatory Assets	1,571,972	902,248
Clearing Accounts	-	-
Miscellaneous Deferred Debits	369,174	206,347
Regulatory Asset State Provision	970,799	779,751
Total Deferred Debits	3,544,320	1,966,524
Total Assets and Other Debits	$ 48,243,515	$ 41,197,426

Pike County Light and Power Company
Balance Sheet
As of September 30, 2024 and 2023

	September 30 2024	September 30 2023
LIABILITIES AND OTHER CREDITS		
Proprietary Capital		
Common Stock Issued	$ -	$ -
Miscellaneous Paid-In Capital	12,450,000	9,950,000
Retained Earnings	7,303,955	6,556,769
Total Proprietary Capital	19,753,955	16,506,769
Long Term Debt		
Bonds - Long-Term	17,487,035	15,285,319
Total Capitalization	37,240,990	31,792,088
Noncurrent Liabilities		
Long Term Obligations	-	-
Total Noncurrent Liabilities	-	-
Current and Accrued Liabilities		
Notes Payable	1,869,665	2,617,121
Accounts Payable	1,857,957	1,688,121
Accounts Payable to Associated Companies	3,403,766	1,328,167
Tax Collections Payable	(297,427)	(288,355)
Customer Deposits	395,955	365,261
Taxes Accrued - Federal	(41,107)	223,527
- Other	1,541	126,767
Interest Accrued	17,403	9,966
Other Current Liabilities	(23,469)	(28,251)
Total Current and Accrued Liabilities	7,184,284	6,042,324
Deferred Credits		
Other Deferred Credits	164,448	173,565
Other Regulatory Liabilities	3,616	(3,467)
Accumulated Deferred Income Taxes - Other Property	1,671,885	1,766,758
Accumulated Deferred Income Taxes - Other	1,978,292	1,426,159
Total Deferred Credits	3,818,241	3,363,015
Total Liabilities and Equity	$ 48,243,515	$ 41,197,426

Pike County Light and Power Company | **Exhibit G-1**
Net Book Value of Electric, Gas and Common Plant-in-Service | **Schedule 2**
As of September 30, 2024

	Electric Plant-in-Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
Intangible Plant			
Franchise and Consents	$ -	$ -	$ -
Total Intangible Plant	-	-	-
Distribution Plant			
Land and Land Rights	1,090,953	-	1,090,953
Structures and Improvements	(2,832)	10	(2,842)
Station Equipment	1,272,591	246,881	1,025,710
Poles, Towers, and Fixtures	13,037,686	1,293,534	11,744,152
Overhead Conductors and Devices	7,090,175	869,846	6,220,329
Underground Conduit	299,714	17,913	281,801
Underground Conductors and Devices	656,996	82,797	574,199
Line Transformers	4,619,252	499,340	4,119,912
Services	2,444,132	295,671	2,148,461
Meters	956,931	261,696	695,234
Street Lighting & Signal Systems	735,150	57,174	677,976
Total Distribution Plant	32,200,747	3,624,862	28,575,885
General Plant			
Structures and Improvements	2,339,399	387,796	1,951,603
Small Tools	365,052	235,043	130,010
Total General Plant	2,704,451	622,839	2,081,612
Electric Excess Reserve	(168,000)	-	(168,000)
Total Electric Plant-in-Service	$ 34,737,197	$ 4,247,701	$ 30,489,497

	Gas Plant-in-Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
Distribution Plant			
Land and Land Rights	$ 744	$ -	$ 744
Mains	4,353,729	249,602	4,104,127
Meas. And Reg. Equip. - General	131,501	30,369	101,132
Services	1,693,812	119,902	1,573,910
Meters	62,823	13,215	49,607
Meter Installations	536,759	52,697	484,062
House Regulator Installations	9,539	1,662	7,877
Industrial Measuring and Regulating Equipment	36,151	7,482	28,669
Total Gas Plant	6,825,059	474,930	6,350,129
General Plant			
Small Tools	346,404	94,753	251,650
Total General Plant	346,404	94,753	251,650
Gas Excess Reserve	22,050	-	22,050
Total Gas Plant-in-Service	$ 7,193,512	$ 569,683	$ 6,623,829

	Common Plant-in-Service	Accumulated Provision for Depreciation & Amortization	Net Book Value
Intangible Plant			
Franchise Trade Name	$ 311,000	$ 167,595	$ 143,405
Total Intangible Plant	311,000	167,595	143,405
General Equipment			
Office Furniture & Equipment	399,087	802,426	(403,339)
Transportation Equipment	596,946	252,900	344,046
Communication Equipment	143,360	139,877	3,483
Misc Equipment	13,477	40,093	(26,616)
Total Common Plant	1,152,869	1,235,296	(82,427)
Retirement Work in Progress		(74,308)	74,308
Total Common Plant-in-Service	$ 1,463,869	$ 1,328,583	$ 135,287

Pike County Light and Power Company
Statement of Income
Twelve Months Ending September 30, 2024

Exhibit G-1
Schedule 3

	Company Total	Electric Department	Gas Department
Operating Revenues:			
Residential Sales	$ 7,779,063	$ 6,139,418	$ 1,639,644
Commercial & Industrial Sales	7,541,477	7,039,827	501,650
Public Lighting Sales	211,526	211,526	-
Total Sales and Delivery of Electricity	15,532,066	13,390,772	2,141,294
Other Operating Revenues			
Miscellaneous Service Revenues (Late Payment Charges)	34,486	28,184	6,301
Rent from Electric Property	(57,902)	(57,902)	-
Other Revenues	525	2,976	(2,451)
Total Other Operating Revenues	(22,892)	(26,742)	3,850
Total Operating Revenues	15,509,174	13,364,029	2,145,145
Operating Expenses:			
Purchased Electric Power Costs	5,187,864	5,187,864	-
Purchased Gas Costs	1,145,888	-	1,145,888
Other Power Supply Expenses	734,868	734,868	-
Distribution Expenses	1,005,781	773,828	231,953
Customer Accounts Expenses	366,204	311,292	54,912
Customer Service Expenses	35,988	30,590	5,398
Administrative And General Expenses	2,490,930	2,148,999	341,931
Depreciation Expense	1,305,110	1,096,950	208,161
Taxes, Other than Income Tax	584,857	560,165	24,691
State Income Taxes	(75,226)	(1,319)	(73,907)
Federal Income Taxes	372,786	358,680	14,106
Total Operating Expenses	13,155,050	11,201,917	1,953,133
Income from Utility Operations	2,354,124	2,162,112	192,012
Taxes - Other Income Deductions:			
Donations	2,559	2,175	384
Other Income Deductions	(105,910)	(90,023)	(15,886)
Total Taxes - Other Income Deductions	(103,351)	(87,848)	(15,503)
Interest Charges:			
Interest on Long Term Debt	1,106,664	940,571	166,093
Amortization of Debt Discount & Expense	16,052	13,644	2,408
Other Interest Expense	42,393	28,006	14,387
Total Interest Charges	1,165,108	982,221	182,888
Net Income	$ 1,292,367	$ 1,267,740	$ 24,627

Pike County Light and Power Company **Exhibit G-1**

Statement of Income - Gas **Schedule 4**

Twelve Months Ending September 30, 2024 and 2023

	September 30 2024	September 30 2023
Operating Revenues:		
Residential Sales	$ 1,639,644	$ 1,874,980
Commercial & Industrial Sales	501,650	569,039
Other Gas Revenue	3,850	36,758
Total Sales and Delivery of Electricity	2,145,145	2,480,776
Operating Expenses:		
Purchased Gas Costs	1,145,888	1,512,182
Distribution Expenses	231,953	224,088
Customer Accounts Expenses	54,912	56,931
Customer Service Expenses	5,398	5,585
Administrative And General Expenses	341,931	332,220
Depreciation Expense	208,161	129,971
Taxes, Other than Income Tax	24,691	17,591
State Income Taxes	(73,907)	7,669
Federal Income Taxes	14,106	20,456
Total Operating Expense	1,953,133	2,306,694
Total Income from Electric Utility Operations	192,012	174,082
Taxes - Other Deductions:		
Donations	384	574
Other Income Deductions	(15,886)	(3,301)
Total Taxes - Other Income Deductions	(15,503)	(2,727)
Interest Charges:		
Interest on Long Term Debt	166,093	136,079
Amortization of Debt Discount & Expense	2,408	1,860
Other Interest Expense	14,387	11,181
Total Interest Charges	182,888	149,120
Net Income - Gas Operations	$ 24,627	$ 27,690

Pike County Light and Power Company

Statement of Direct and Allocated Charges From Corning Natural Gas Corporation

Twelve Months Ending September 30, 2024

Operation and Maintenance Expenses		**Direct Charges**	**Allocated Charges**	**Total Charges**
Purchased Gas Expense				
803	Deferred Gas Supply Expense	$ 201,513		$ 201,513
804	Gas Supply Expense-Purchases	944,375		944,375
813	Gas Supply-Utility Agreement	-	-	-
	Total Purchased Gas Expenses	$ 1,145,888	$ -	$ 1,145,888
Distribution Expenses - Operation				
870	Operation Supervision and Engineering	$ 5,755	$ -	$ 5,755
874	Mains and Services Expenses	-	-	-
	Total Operation	5,755	-	5,755
Distribution Expenses - Maintenance				
885	Maintenance Supervision and Engineering	-	-	-
887	Maintenance of Mains	5,277	-	5,277
889	Maint. of Measuring and Regulating Station Equip. - General	-	-	-
890	Maint. of Measuring & Regulator Station Equip. - Industrial	-	-	-
892	Maintenance of Services	165,848	55,073	220,921
893	Maintenance of Meters and Home Regulators	-	-	-
	Total Maintenance	171,125	55,073	226,198
	Total Distribution Expenses	176,880	55,073	231,953
Customer Accounts Expenses - Operation				
902	Meter Reading Expense	2,982	-	2,982
903	Customer Records and Collection Expenses	36,158	-	36,158
904	Uncollectible Accounts	14,475	-	14,475
	Total Customer Accounts Expenses	53,614	-	53,614
Customer Service & Information Expenses - Operation				
908	Customer Service & Informational Expenses (Non-Major	-	-	-
909	Supervision	-	-	-
910	Customer Assistance Expense	-	-	-
911	Informational and Instructional Expense	5	1,293	1,298
912	Miscellaneous Customer Service Expense	-	-	-
913	Rents	-	-	-
	Total Customer Service & Informational Expenses	$ 5	$ 1,293	$ 1,298
Sales Promotion Expense - Operation				
917	Promotional Advertising	5,398	$ -	5,398
	Total Sales Promotion Expense	5,398	-	5,398
Administrative and General Expenses - Operation				
920	Administrative and General Salaries	42,273	105,193	147,467
921	Office Supplies and Expenses	5,515	45,412	50,927
922	Administrative Expenses Transferred - Credit	(46,694)	-	(46,694)

923	Outside Services Employed	31,074	33,997	65,071
924	Property Insurance	(38,685)	39,021	336
925	Injuries and Damages	23,970	-	23,970
926	Employee Pensions and Benefits	41,140	24,735	65,875
926.1	Health and Group Life Expenses	-	-	-
926.2	Pension Expenses	-	-	-
926.3	Other Post Retirement Benefit Expenses	-	-	-
928	Regulatory Commission Expenses	20,677	-	20,677
929	Duplicate Charges - Credit	-	-	-
930.1	General Advertising Expenses	-	-	-
930.2	Miscellaneous General Expenses	3,268	-	3,268
930.6	Miscellaneous General Expenses - Vehicles	1,778	3,322	5,100
931.1	General Rents	-	-	-
931	Expenses of Data Processing Equipment	-	-	-
	Total Operation	84,316	251,679	335,995
Administrative and General Expenses - Maintenance				
932	Maintenance of General Plant	5,936		5,936
	Total Maintenance	5,936	-	5,936
	Total Administrative and General Expense	90,252	251,679	341,931
Total Operations and Maintenance		$ 1,472,036	$ 308,045	$ 1,780,082

Pike County Light and Power Company — **Exhibit G-1**

Statement of Direct and Allocated Charges From Corning Natural Gas Corporation — **Schedule 5**

Twelve Months Ending September 30, 2024 — **Page 2 of 2**

Other Charges for Operations		**Direct Charges**	**Allocated Charges**	**Total Charges**
Other Income and Expense Accounts				
408	Taxes Other Than Income Taxes	$ 23,987	$ 705	$ 24,691
425	Miscellaneous Amortizations	3,110	-	3,110
426.1	Donations	118	265	384
426.5	Other Income Deductions	-	-	-
430	Other Interest Charges	-	-	-
Balance Sheet Accounts				
101	Gas Plant In Service	1,011,512	-	1,011,512
108	Accumulated Provision for Depreciation	151,345	-	151,345
131	Cash & TCI's	424,581	-	424,581
142	Customer Accounts Receivable	158,854	-	158,854
150	Materials and Supplies	(1,041,396)	-	(1,041,396)
165	Prepayments	584,590	-	584,590
190	Accumulated Deferred Income Tax	191,048	-	191,048
232	Accounts Payable	169,837	-	169,837
253	Other Deferred Credits	(2,034)	-	(2,034)
283	Accumulated Deferred Income Tax	457,260	-	457,260
	Total Other Charges for Operations	2,132,812	970	2,133,782
Total Charges for Operations & Maintenance		$ 3,604,849	$ 309,016	$ 3,913,864

Pike County Light and Power Company
Common Expense Allocation

Allocation Factor			Applicable Services
A	**Accounts Payable Factors**		Accounts Payable Processing
	CNG	91.50%	
	Pike Electric	6.14%	
	Pike Gas	1.25%	
	Leatherstocking Gas	1.11%	
B	**General Plant Factor**		
	CNG	97.20%	
	Pike Electric	1.73%	
	Pike Gas	0.35%	
	Leatherstocking Gas	0.72%	

CNG Personnel Providing Service to Various Companies (based on time Spent)

Payroll allcation for the period March 2024 to February 2025

Empolyee	Position	Corning Natural		Pike Electric		Pike Gas		LGC	
		%	Account	%	Account	%	Account	%	Account
Karen Smith	Regulatory Accountant A	100.00%	920000	0.00%	140430	0.00%	140430	0.00%	140340
Ed Buck	Regulatory Accountant B	99.00%	920000	0.83%	140430	0.18%	140430	0.00%	140340
Paul DiValentino	Data Reporting Analyst	68.77%	920000	20.62%	140430	4.34%	140430	6.27%	140340
Derek Echevarria	Regulatory Accountant C	0.00%	920000	61.04%	140430	22.71%	140430	16.25%	140340
Michele Peterson	Fixed Asset/Accounts Payable Analyst.	66.53%	920000	22.85%	140430	4.53%	140430	6.09%	140340
Erin Hysell	Inventroy/Fixed Asset Clerk (Angela Constant)	66.53%	920000	22.85%	140430	4.53%	140430	6.09%	140340
Jessica Ector	Accounts Payable & Regulatroy Assistant	68.92%	920000	21.85%	140430	3.86%	140430	5.37%	140340
Welch, Sheila	H.R. Manager	80.83%	920000	12.58%	140430	2.81%	140430	3.77%	140340
Kemp, Stephanie	Human Resources Specialist	81.98%	920000	8.86%	140430	4.52%	140430	4.64%	140340
Faulk, Charlene	VP of Customer Service and IT	45.39%	903000	18.50%	140430	3.90%	140430	2.21%	140340
Faulk, Charlene	VP of Customer Service and IT	20.63%	920000	6.19%	140430	1.30%	140430	1.88%	140340
Morich, Heather	Billing Manager	79.23%	903000	15.69%	140430	2.77%	140430	2.31%	140340
Shannon Rodriguez	Billing C lerk	79.23%	903000	15.69%	140430	2.77%	140430	2.31%	140340
DelGrosso, Samara	Customer Service Manager	100.00%	903000	0.00%	140430	0.00%	140430	0.00%	140340
Mike Carpenter	I.T. Director	68.77%	920000	20.62%	140430	4.34%	140430	6.27%	140340
Winters, Andrew	SCADA Tech	60.80%	184090	29.38%	140430	7.50%	140430	2.32%	140340
German, Michael	CEO	68.77%	920000	20.62%	140430	4.34%	140430	6.27%	140340
Spear, Jeff	VP and COO	60.80%	184090	29.38%	140430	7.50%	140430	2.32%	140340
Fink, Kevin	VP of Engineering Operations	100.00%	184090						
Lewis, Julie	VP of Energy Supply and Corporate Secetary	37.82%	920000	11.34%	140430	2.39%	140430	3.45%	140340
Lewis, Julie	VP of Energy Supply and Corporate Secetary	45.00%	813000						
Mancini, Katrina	Customer Affairs Manager	0.00%	912000	17.00%	140430	3.00%	140430	0.00%	140340
Mancini, Katrina	Customer Affairs Manager	16.00%	920000	56.00%	140430	0.00%	140430	8.00%	140340
Stephens, Abram	Energy Supply Specialist	50.00%	813000	50.00%	140430	0.00%	140430	0.00%	140340
Stillman, Justin	Energy Supply Specialist	50.00%	813000	50.00%	140430	0.00%	140430	0.00%	140340
Marie Husted	Director of Energy Services	90.00%	813000	0.00%	140430	0.00%	140430	0.00%	140340
Marie Husted	Director of Energy Services	0.00%	920000	6.38%	140430	1.13%	140430	2.50%	140340

Pike Personnel Providing Service to Various Companies (based on time Spent)

Payroll allcation for the period March 2024 to February 2025

Empolyee	Position	Corning Natural Gas		Pike Electric		Pike Gas		LGC	
Lenns, Chuck	VP Finance (Chuck Lenns)	70.23%	920000	19.82%	140430	4.06%	140430	5.89%	140340

Pike County Light and Power Company **Exhibit G-1**

Intercompany Accounts - Receivable / Payable to Corning Natural Gas Corporation **Schedule 7**

Accounts 146 / 234

As of September 30, 2024

Net Payable to Corning Natural Gas Corporation at September 30, 2023	$	1,314,631
Common Expense Allocation		1,358,816
Administrative Payroll Allocation		701,288
Federal Income Taxes		(342,052)
Other movements		116,168
Payments Made During Year		88,958
Net Payable to Corning Natural Gas Corporation at September 30, 2024	$	3,237,810

Pike County Light And Power Company
Index of Schedules
Capitalization and Rate of Return

Exhibit G-2

Schedule	Title of Schedule	Witness
(1)	Capitalization of Pike County Light And Power Company	C. Lenns & M. Lenns
(2)	Long Term Debt Schedule Pike County Light & Power Company	C. Lenns & M. Lenns
(3)	Cost of Money for Pike County Light and Power Company	C. Lenns & M. Lenns

Pike County Light And Power Company
Capitalization

	As of September 30, 2024 (Actual)		As of September 30, 2025 (Forecast)	
	Amount	Percent	Amount	Percent
Long Term Debt:	$ 17,584,425	44.69%	$ 17,584,425	40.72%
Average Short Term Debt (a)	2,006,792	5.10%	3,733,122	8.64%
Proprietary Capital				
Common Stock	-		-	
Paid In Capital	12,450,000		12,450,000	
Retained Earnings	7,303,955		9,415,776	
Total Proprietary Capital:	19,753,955	50.21%	21,865,776	50.63%
Total Capitalization	$ 39,345,172	100.00%	$ 43,183,323	100.00%

(a) Represents the daily average balance (October 1, 2023 - September 30, 2024. The balance at September 30, 2024 was $1,852,208.

Pike County Light And Power Company

Long Term Debt
At September 30, 2024 (Actual)

Pike County Light & Power Company	Company Accounts	Issue Date	Maturity Date	Original Issue Amount	Amount Outstanding	Unamortized Expense of Issue	Net Proceeds	x	Cost of Debt %	=	Effective Annual Cost (a)
CEC - Intercompany Loan											
Loan 1 - 6.31% (two tranche blended rate)	224900	9/12/24	9/12/34	$ 17,584,425	$ 17,584,425	$ 535,219	$ 17,049,205		6.82%		$ 1,163,602
Total				**$ 17,584,425**	**$ 17,584,425**	**$ 535,219**	**$ 17,049,205**		6.82%		**$ 1,163,602**

(a) The effective annual cost of debt represents the annualized interest expense (September 30th debt balance x coupon interest rate) plus the annual amortization of debt issuance costs

Not The long-term debt of Corning Energy Corporation was refinanced on September 12, 2024, replaceing external debt held by M&T Bank and Wayne Bank with new private placement long-term notes with private investors (Prudential Insurance & BlackRock Capital). The loans are interest only payable loans, with interest payments occurring every six months. The principal was split into two tranches, with the first tranche payable after 10 years, and the second tranches payable after 12 years. The amount of debt on Pike's books is the new amount of long-term debt is the new intercompany loan from Corning Energy Corporation (parent) down to Pike County Light and Power Company.

Pike County Light And Power Company

Long Term Debt
At September 30, 2025 (Forecast)

Pike County Light & Power Company	Company Accounts	Issue Date	Maturity Date	Original Issue Amount	Amount Outstanding	Unamortized Expense of Issue	Net Proceeds	x	Cost of Debt %	=	Effective Annual Cost (a)
CEC - Intercompany Loan											
Loan 1 - 6.31% (two tranche blended rate)	224900	9/12/24	9/12/34	$ 17,584,425	$ 17,584,425	$ 481,697	$ 17,102,727		6.80%		$ 1,163,602
Total				**$ 17,584,425**	**$ 17,584,425**	**$ 481,697**	**$ 17,102,727**		6.80%		**$ 1,163,602**

(a) The effective annual cost of debt represents the annualized interest expense (September 30th debt balance x coupon interest rate) plus the annual amortization of debt issuance costs

Not The long-term debt of Corning Energy Corporation was refinanced on September 12, 2024, replaceing external debt held by M&T Bank and Wayne Bank with new private placement long-term notes with private investors (Prudential Insurance & BlackRock Capital). The loans are interest only payable loans, with interest payments occurring every six months. The principal was split into two tranches, with the first tranche payable after 10 years, and the second tranches payable after 12 years. The amount of debt on Pike's books is the new amount of long-term debt is the new intercompany loan from Corning Energy Corporation (parent) down to Pike County Light and Power Company.

Exhibit G-2
Schedule 3

Pike County Light And Power Company
Consolidated Cost of Money

Forecast at September 30, 2025

	Percent of Capital	Cost of Component		Weighted Cost	Pre-Tax Weighted Cost
Long Term Debt	40.72%	6.80%		2.77%	2.77%
Short Term Debt	8.64%	7.58%	(a)	0.66%	0.66%
Common Stock Equity	50.63%	10.20%		5.16%	7.15%
Total Capitalization	100.00%			8.59%	10.58%

(a) Based on short-term line of Credit Rate currently in effect

Pike County Light And Power Company
Index of Schedules
Gas Rate Base

Exhibit G-3

Schedule	Title of Schedule	Witness
Summary	Gas Rate Base	C. Lenns & M. Lenns
(1)	Plant - Additions & Retirements	C. Lenns & M. Lenns
(2)	Depreciation Reserve	C. Lenns & M. Lenns
(3)	Gas Working Capital Requirements	C. Lenns & M. Lenns
(4)	Change in Material and Supplies	C. Lenns & M. Lenns
(5)	Change in Working Capital Prepayments	C. Lenns & M. Lenns
(6)	Changes to Rate Base for Deferred Debits	C. Lenns & M. Lenns
(7)	Changes to Rate Base for Deferred Debits	C. Lenns & M. Lenns
(8)	Changes in Customer Deposits	C. Lenns & M. Lenns
(9)	Changes in Deferred Income Taxes	C. Lenns & M. Lenns
(10)	Gas Capital Expenditures	E. Verbraak
(11)	Gas Plant Additions	E. Verbraak

Pike County Light And Power Company
Gas Rate Base
At September 30, 2024 And 2025

Description	Actual Per Books at 9/30/2024	Difference Between Historical and Future Years: Reference	Difference Between Historical and Future Years: Amount	Future Year at 9/30/2025	Schedule No.
	(a)	(b)	(c)	(d)=(a)+(c)	
Utility Plant:					
Gas Plant in Service	$ 7,193,500	(1a)	$ 4,020,642	$ 11,214,142	1
Common Plant in Service (Allocated)	172,900	(1b)	68,100	241,000	1
Interco plant allocated from Corning Gas (Net)	-	(1c)	41,600	41,600	1
CWIP not taking interest	453,000	(1d)	(453,000)	-	1
Total Utility Plant	7,819,400		3,677,342	11,496,742	
Utility Plant Reserves:					
Accumulated Provision For Depreciation					
of Gas Plant in Service	569,700	(2a)	185,400	755,100	2
of Common Plant in Service (Allocated)	199,300	(2b)	(900)	198,400	2
Total Utility Plant Reserves	769,000		184,500	953,500	
Net Plant	7,050,400		3,492,842	10,543,242	
Additions to Net Plant					
Working Capital Requirements:					
Cash Working Capital	(24,600)	(3)	143,400	118,800	3
Materials and Supplies	271,000	(4)	5,800	276,800	4
Prepayments	5,400	(5)	100	5,500	5
Deferred Debits (Net of Tax)	16,500	(6)	18,200	34,700	6
Total Additions	268,300		167,500	435,800	
Deductions to Net Plant:					
Deferred Credits (Net of Tax)	1,600	(7)	(6,000)	(4,400)	7
Customer Deposits	58,700	(8)	600	59,300	8
Accumulated Deferred Income Taxes	255,100	(9)	(10,000)	245,100	9
Total Deductions	315,400		(15,400)	300,000	
Gas Rate Base	$ 7,003,300		$ 3,675,742	$ 10,679,042	

Pike County Light And Power Company
Changes in Gas Rate Base
For the 12 Months Ended September 30, 2025

Adjustment Number	Description	Amount
(1a)	Changes in Plant in Service - Additions & Retirements	$ 4,020,642
(1b)	Changes to Common Plant	68,100
(1c)	Changes to Intercompany Plant allocated to Pike Gas	41,600
(1d)	Changes to Construction Work in Progress	(453,000)
(2a)	Changes to Gas Depreciation Reserve - Existing Depreciation Rates	185,400
(2b)	Changes to Common Plant - Depreciation	(900)
(3)	Changes in Working Capital Requirements (O&M)	143,400
(4)	Change in Material and Supplies	5,800
(5)	Change in Working Capital Prepayments	100
(6)	Changes to Rate Base for Deferred Debits	18,200
(7)	Changes to Rate Base for Deferred Credits	(6,000)
(8)	Changes in Customer Deposits	600
(9)	Changes in Deferred Income Taxes	(10,000)

Pike County Light And Power Company
Statement in Support of Change No. (1a)
To Gas Plant in Service
For the Twelve Months Ended September 30, 2025

Gas Plant in Service		Amount
Balance at September 30, 2024		**$ 7,193,500**
Additions - Completed CWIP at September 30, 2024 Change (1d) *	**$ 453,042**	
Additions - October 1, 2024 thru September 30, 2025	2,500,000	
Additions - October 1, 2025 thru March 31, 2026	1,250,000	
Total Additions		4,203,042
Retirements - October 1, 2024 thru September 30, 2025	(121,600)	
Retirements - October 1, 2025 thru March 31, 2026	(60,800)	
Total Retirements		(182,400)
Net Additions (Change No. 1b)		**4,020,642**
Ending Balance at September 30, 2025		**$ 11,214,142**

* See G-3, Schedule 1, Page 4 of 4

Pike County Light And Power Company
Statement in Support of Change No. (1b)
To Gas Plant in Service
For the Twelve Months Ended September 30, 2025

Common Plant in Service			Total Amount	Gas Allocation (Rounded) 15%
Balance at September 30, 2024			$ 1,152,869	**$ 172,900**
Additions - Completed CWIP at September 30, 2024 Change (1d) *		**$ -**		
Additions - October 1, 2024 thru September 30, 2025		600,000		90,000
Additions - October 1, 2025 thru March 31, 2026		200,000		30,000
Total Additions			800,000	120,000
Retirements - October 1, 2024 thru September 30, 2025		(230,600)		(34,600)
Retirements - October 1, 2025 thru March 31, 2026	**	(115,300)		(17,300)
Total Retirements			(345,900)	(51,900)
Net Additions (Change No. 1)			454,100	**68,100**
Ending Balance at September 30, 2025			$ 1,606,969	**$ 241,000**

* See G-3, Schedule 1, Page 4 of 4

** General Plant, excluding structures, is amortized over 5 - 10 years. Plant of approximately $300,000 will be fully amortized and retired in September 2025.

Pike County Light And Power Company
Statement in Support of Change No. (1c)
To Gas Plant in Service
For the Twelve Months Ended September 30, 2025

Intercompany Plant Allocated from Corning Gas (Net)	At September 30, 2024				% Allocated		
Shared Corning Facilities	Original Cost	Depreciation Reserve	Net Plant		To Pike Allocation		Gas Allocation
Land Williams Street	$ 155,733	$ -	$ 155,733				
West William Street Office	2,218,962	(1,118,465)	1,100,496				
Land Riverside	233,732		233,732				
Riverside Operations Facility	3,115,129	(1,570,178)	1,544,952				
Total	$5,723,556	$(2,688,643)	$3,034,913	x	0.68%	=	$ 20,563
Shared Corning Office Furniture & Equipment							
Office Furniture & Equipment - Furniture	$ 139,653	$ (121,383)	$ 18,270				
Office Furniture & Equipment - Machines	292,642	(179,719)	112,923				
Office Furniture & Equipment - Computers	4,305,715	(1,332,252)	2,973,463				
Total	$4,738,010	$(1,633,354)	$3,104,656	x	0.68%	=	21,036
(Change No. 1c)							**$ 41,599**
Rounded							**$ 41,600**

Pike County Light And Power Company
Statement in Support of Change No. (1d)
To Gas Plant in Service
For the Twelve Months Ended September 30, 2025

CWIP Projects Completed At June 30, 2020		Total Amount (A)	Gas Allocation (B)	Gas Plant In-Service (Rounded) (C) = (A) x (B)
Gas Distribution Plant Additions (Change No. 1d)	*	$ 453,042	100%	**$ 453,000**
General Plant Additions (Change No. 1d)	**	-	15%	**-**
Net Transfers to Plant In-Service (Change No. 1d)				**$ 453,000**

***** See G-3, Schedule 1, Page 1 of 4

****** See G-3, Schedule 1, Page 2 of 4

Pike County Light And Power Company
Statement in Support of Change No. (2a)
To Gas Depreciation Reserve
For the Twelve Months Ended September 30, 2025

Accumulated Provision for Depreciation of Gas Plant		Amount
Balance at September 30, 2024		$ 569,700
Additions - October 1, 2024 thru September 30, 2025	$ 220,400	
Additions - October 1, 2025 thru March 31, 2026	147,400	
Total Additions		367,800
Retirements - October 1, 2024 thru September 30, 2025	(121,600)	
Retirements - October 1, 2025 thru March 31, 2026	(60,800)	
Total Retirements		(182,400)
Net Additions (Change No. 2a)		**185,400**
Ending Balance at September 30, 2025		$ 755,100

Pike County Light And Power
Statement in Support of Change No. (2b)
To Common Depreciation Reserve
For the Twelve Months Ended September 30, 2025

Accumulated Provision for Depreciation on Common Plant		Total Amount	Electric Allocation Rounded 15%
Balance at September 30, 2024		$ 1,328,583	**199,300**
Additions - October 1, 2024 thru September 30, 2025	212,200		
Additions - October 1, 2025 thru March 31, 2026	127,500		
Total Additions		339,700	51,000
Retirements - October 1, 2024 thru September 30, 2025	(230,600)		
Retirements - October 1, 2025 thru March 31, 2026	(115,300)		
Total Retirements		(345,900)	(51,900)
Net Additions (Change No. 2b)		(6,200)	**(900)**
Ending Reserve Balance at September 30, 2025		$ 1,322,383	**$ 198,400**

Pike County Light And Power Company
Statement in Support of Change No. (3)
For The Twelve Months Ended September 30, 2024

	Reference	Amount	(Lead) / Lag Days	Dollar Days
Revenue Recovery	Sch. 1	$ 2,145,200	21.3	$ 45,649,856
Gas Supply Expenses:	Sch. 2	1,145,900	10.0	11,447,541
Deferred Purchased Gas	Sch 2	(201,513)	(107.5)	21,662,632
Pike Salaries & Wages	Sch. 3	274,267	8.0	2,194,136
401K Pension Match	Sch. 4	5,549	8.0	44,393
Employee Welfare Expenses	Sch. 5	70,356	23.0	1,618,185
Intercompany Charges	Sch. 6	780,177	30.0	23,405,319
Uncollectible Accounts Accrual	Sch. 7	14,475	8.0	115,800
Other O&M	Sch. 7	(322,323)	23.0	(7,413,438)
Amortizations:				-
Rate Case Costs	Sch. 5	-	-	-
PUC Assessment	Sch. 5	4,978	-	-
Insurance	Sch. 8	8,234	-	-
Depreciation & Amortization	Sch. 8	208,200	-	-
Taxes Other - Payroll	Sch. 4	24,700	8.0	197,600
- Property Tax	Sch. 8	-	-	-
Income Taxes:				-
Federal Income Tax	Sch. 9	32,430	30.0	972,896
Deferred Federal Income Tax	Sch. 8	(32,430)	-	-
Corporate Business Tax (State)	Sch. 10	12,339	30.0	370,164
Deferred Corporate Business Tax	Sch. 8	(12,339)	-	-
Return on Invested Capital	Sch. 8	234,100	-	-
Total Requirement		2,247,100	24.3	54,615,228
		-		
Net Lag			(3.0)	$ (8,965,372)
Net Requirement (Net Lag / 365)				$ (24,563)
Rounded				$ (24,600)

Pike County Light And Power Company
Statement in Support of Change No. (3)
For The Twelve Months Ended September 30, 2025

	Amount	(Lead) / Lag Days	Dollar Days
Revenue Recovery	3,373,900	21.3	$ 71,796,592
Gas Supply Expenses:	1,135,000	10.0	11,338,650
Pike Salaries & Wages	291,667	8.0	2,333,336
401K Pension Match	6,499	8.0	51,993
Employee Welfare Expenses	82,889	23.0	1,906,444
Intercompany Charges	787,977	30.0	23,639,319
Uncollectible Accounts Accrual	6,175	8.0	49,400
Other O&M	(505,785)	23.0	(11,633,061)
Amortizations:			-
Rate Case Costs	9,400	-	-
PUC Assessment	4,978	-	-
Insurance	13,500	-	-
Depreciation & Amortization	333,100	-	-
Taxes Other - Payroll	27,700	11.0	304,700
- Property Tax	-	-	-
Income Taxes:			-
Federal Income Tax	10,440	30.0	313,200
Deferred Federal Income Tax	(10,440)	-	-
Corporate Business Tax (State)	3,972	30.0	119,160
Deferred Corporate Business Tax	(3,972)	-	-
Return on Invested Capital	1,077,000	-	-
Total Requirement	3,270,100	8.7	28,423,141
Net Lag		12.6	43,373,451
Net Requirement (Net Lag / 365)			$ 118,831
Historical Cash Working Capital			(24,600)
Net Change			$ 143,431
Rounded			$ 143,400

Pike County Light And Power Company
Statement in Support of Change No. (4)
Materials and Supplies
For the Twelve Months Ended September 30, 2025

Exhibit G-3
Schedule 4

Month		Materials & Supplies Inventory Acct 150020	Gas Allocation
		(1)	(2)
October 31, 2023	Actual	1,846,765	$ 277,015
November 30, 2023	Actual	1,797,373	269,606
December 31, 2023	Actual	1,803,696	270,554
January 31, 2024	Actual	1,706,599	255,990
February 29, 2024	Actual	1,736,717	260,508
March 31, 2024	Actual	1,778,928	266,839
April 30, 2024	Actual	1,781,018	267,153
May 31, 2024	Actual	1,811,206	271,681
June 30, 2024	Actual	1,817,367	272,605
July 31, 2024	Actual	1,857,767	278,665
August 31, 2024	Actual	1,843,697	276,554
September 30, 2024	Actual	1,899,337	284,901
October 31, 2024	Actual	1,897,232	284,585
November 30, 2024	Actual	2,207,948	331,192
October 2023 - September 30, 2024 Total		$ 21,680,469	$ 3,252,070
September 30, 2024 - Twelve Month Average		$ 1,806,706	$ 271,006
Rounded			$ 271,000
December 2023 - November 2024 Total		$ 22,141,511	$ 3,321,227
Twelve Month Average		$ 1,845,126	$ 276,769
Rounded			$ 276,800
Net Changes (Change No. 4)			5,800
Twelve Month Average September 30, 2025			$ 276,800

Pike County Light And Power Company
Statement in Support of Change (5)
Gas Working Capital Prepayments

Exhibit G-3
Schedule 5

Month		Gas PaPUC Assessment Acct. 05 165202	Common Property Tax Acct. 05 165110	Property Insurance Acct. 05 165030	Total
October 31, 2023	Actual	$ 6,695	$ 10,799	$ -	$ 17,494
November 30, 2023	Actual	6,087	9,395	-	15,482
December 31, 2023	Actual	5,478	7,992	-	13,470
January 31, 2024	Actual	4,869	6,588	-	11,458
February 29, 2024	Actual	4,261	9,870	-	14,131
March 31, 2024	Actual	3,652	8,467	-	12,119
April 30, 2024	Actual	3,043	7,048	-	10,091
May 31, 2024	Actual	2,435	5,630	-	8,064
June 30, 2024	Actual	1,826	4,211	-	6,037
July 31, 2024	Actual	1,217	14,498	-	15,715
August 31, 2024	Actual	609	12,015	-	12,624
September 30, 2024	Actual	8,460	10,561	-	19,021
October 31, 2024	Actual	7,691	9,106	-	16,797
November 30, 2024	Actual	6,922	7,651	-	14,573
October 2023 - September 30, 2024 Total		$ 48,632	$ 107,073	$ -	$ 155,705
September 30, 2024 - Twelve Month Average		$ 4,053	$ 8,923	$ -	$ 12,975
x Gas Allocation		100%	15%	15%	-
Gas Twelve Month Average		$ 4,053	$ 1,338	$ -	$ 5,391
Rounded					$ 5,400
December 2023 - November 2024 Total		$ 50,462	$ 103,637	$ -	$ 154,099
Twelve Month Average		$ 4,205	$ 8,636	$ -	$ 12,842
x Gas Allocation		100%	15%	15%	-
Gas Twelve Month Average		$ 4,205	$ 1,295	$ -	$ 5,501
Rounded					$ 5,500
Net Changes (Change No. 5)					100
Twelve Month Average September 30, 2025					$ 5,500

Pike County Light And Power Company
Statement in Support of Change (6)
For the Twelve Months Ended September 30, 2025

Exhibit G-3
Schedule 6

Deferred Debit Items	Rate Case Acct 186172 & 186185	After Tax (b)	Rounded
Deferred Debit Balance as of September 30, 2024	$ 22,854	$ 16,522	$ 16,500
Deferred Charges 10/1/2024 - 9/30/2025 (a)	37,500	27,110	27,100
Less: Amortization of Deferred Charges 10/1/24 - 9/30/25	(12,379)	(8,949)	(8,900)
Deferred Debit Balance as of September 30, 2025	47,975	$ 34,682	$ 34,700
Net Change			$ 18,200

(a) See Exhibit G-4, Schedule 5 for projected rate case expenditures

(b) Calculation of After Tax Factor:

	SIT Rate =	8.4900%
+	FIT Rate =	21.0000%
+	SIT Rate Net of FIT Rate [8.49% x (1-21%)] =	6.7071%
=	Effective Net FIT / SIT Rate =	27.7071%
	Net of SIT & FIT Multiplier (1/1-27.7071%)	72.2929%

Pike County Light And Power Company
Statement in Support of Change (7)
For the Twelve Months Ended September 30, 2025

Exhibit G-3
Schedule 7

Deferred Credit Items	FIT Tax Rate Change Accts. 253912 & 253922	After Tax *	Rounded
Negative Deferred Credit Balance as of September 30, 2024	$ 2,275	$ 1,644	$ 1,600
Deferred Credits 10/1/2024 - 9/30/2025	-	-	-
Less: Amortization of Deferred Charges 10/1/2024 - 9/30/2025	(8,303)	(6,003)	(6,000)
Negative Deferred Credit Balance as of September 30, 2025	$ (6,029)	$ (4,358)	$ (4,400)
Net Change			$ (6,000)

	Calculation of After Tax Factor:	
*	SIT Rate =	8.4900%
+	FIT Rate =	21.0000%
+	SIT Rate Net of FIT Rate [8.49% x (1-21%)] =	6.7071%
=	Effective Net FIT / SIT Rate =	27.7071%
	Net of SIT & FIT Multiplier (1/1-27.2929%)	72.2929%

Pike County Light And Power Company
Statement in Support of Change No. (8)
Customer Deposits
For the Twelve Months Ended September 30, 2025

Exhibit G-3
Schedule 8

Month		Customer Deposits Acct 235000	Gas Allocation
		(1)	(2)
October 31, 2023	Actual	$ 365,513	$ 54,827
November 30, 2023	Actual	384,614	57,692
December 31, 2023	Actual	387,605	58,141
January 31, 2024	Actual	391,875	58,781
February 29, 2024	Actual	391,681	58,752
March 31, 2024	Actual	393,088	58,963
April 30, 2024	Actual	396,434	59,465
May 31, 2024	Actual	396,700	59,505
June 30, 2024	Actual	397,597	59,640
July 31, 2024	Actual	397,190	59,579
August 31, 2024	Actual	393,769	59,065
September 30, 2024	Actual	395,955	59,393
October 31, 2024	Actual	400,461	60,069
November 30, 2024	Actual	399,078	59,862
October 2023 - September 30, 2024 Total		$ 4,692,025	$ 703,804
September 30, 2024 - Twelve Month Average		$ 391,002	$ 58,650
Rounded			$ 58,700
December 2023 - November 2024 Total		$ 4,741,437	$ 711,215
Twelve Month Average		$ 395,120	$ 59,268
Rounded			$ 59,300
Net Changes (Change No. 4)			600
Twelve Month Average September 30, 2025			$ 59,300

Pike County Light And Power Company
Statement in Support of Change No. (9)
To Accumulated Deferred Income Taxes
For the Twelve Months Ended September 30, 2025

Exhibit G-3
Schedule 9

Accumulated Deferred Income Taxes		Balance Accounts 282012 / 282082
Balance at September 30, 2024		$ 255,100
Additions - October 1, 2024 thru September 30, 2025		
Tax Depreciation - Normalized	255,285	
Less: Book Depreciation	252,230	
Net Schedule M Tax Deduction	3,055	
x Effective SIT / FIT Tax Rate	27.7071%	
Net Additions October 1, 2024 thru September 30, 2025		800
Additions - July 1, 2021 thru December 31, 2021		
Tax Depreciation - Normalized	127,642	
Less: Book Depreciation	166,525	
Net Schedule M Tax Deduction	(38,883)	
x Effective SIT / FIT Tax Rate	27.7071%	
Net Additions October 1, 2025 thru March 31, 2026		(10,800)
Net Additions (Change No. 7)		**$ (10,000)**
Ending Balance at September 30, 2025		$ 245,100

Pike County Light And Power Company
Gas Capital Expenditures / Closed Outs to Plant
For the Twelve Months Ended September 30, 2025
$000's

Gas Plant Account	FERC Account	Close Out To Plant In Service	Annual Spending January 2025 - December 2025	Annual Spending January 2026 - December 2026	Total
Pipe Replacement Program	376	Monthly	$ 1,353	$ 2,059	$ 3,412
Recurring Capital Budget Upgrades / Replacements					
Mains	376	Monthly	$ 120	$ 123	$ 243
Measuring and Regulating Station Equipment	378	Monthly	55	57	112
Services	380	Monthly	781	132	913
Meters	381	Monthly	13	10	23
House Regulators	383	Monthly	105	110	215
Subtotal Recurring Upgrades / Replacements			$ 1,074	$ 432	$ 572
Total Gas Distribution Plant			$ 2,427	$ 2,494	$ 4,284
General Plant Account					
Office Furniture	390	Monthly	$ 71	$ 51	$ 122
IT Equipment	391	Monthly	237	39	275
Transportation Equipment	392	Monthly	150	125	275
Contractor Work / Other		Monthly	162	247	409
Tools, Shop and Garage Equipment	394	Monthly	24	25	49
Total General Plant Construction Projects			**$ 643**	**$ 487**	**$ 1,130**

Pike County Light And Power Company
Gas Plant Additions
For the Twelve Months Ended September 30, 2025
$000's

Exhibit G-3
Schedule11

Gas Plant Account	FERC Account	In Service Date	October 2024 - September 2025	October 2025 - March 2026	Total
LTIIP Program:					
Pipe Replacement Program (LTIIP)	376	Monthly	1,706	1,030	2,736
Recurring Capital Budget Upgrades / Replacements					
Mains	376	Monthly	122	62	$ 183
Measuring and Regulating Station Equipment	378	Monthly	56	29	85
Services	380	Monthly	457	66	523
Meters	381	Monthly	12	5	17
House Regulators	383	Monthly	108	55	163
					-
Total Gas Plant Additions			**$ 2,459**	**$ 1,246**	**$ 3,705**
Rounded			**$ 2,500**	**$ 1,250**	**$ 3,750**
General Plant Account					
Office Furniture	390	Monthly	$ 61	$ 26	$ 86
IT Equipment	391	Monthly	138	19	157
Transportation Equipment	392	Monthly	138	63	200
Contractor Work / Other		Monthly	204	124	328
Tools, Shop and Garage Equipment	394	Monthly	25	13	37
Total General Plant Additions			**$ 565**	**$ 243**	**$ 809**
Rounded			**$ 600**	**$ 200**	**$ 800**

Pike County Light And Power Company
Index of Schedules
Gas Cost of Service

Exhibit G-4

Schedule	Title of Schedule	Witness
Summary	Gas Cost of Service	C. Lenns & M. Lenns
(1)	Changes in billed revenue to reflect forecast sales	C. Lenns & M. Lenns
(2)	Change to cost of purchased gas cost to match forecast recoveries	C. Lenns & M. Lenns
(3)	Changes in Operations and Maintenance Expenses to reflect increases in Wages and Salaries and Additional Employee Positions	C. Lenns & M. Lenns
(4)	Changes in Operations and Maintenance Expenses to reflect increases in Payroll Ancillary Costs	C. Lenns & M. Lenns
(5)	Changes in Operation and Maintenance Expenses to reflect amortization of rate case costs	C. Lenns & M. Lenns
(6)	Changes in Operation and Maintenance Expenses to reflect current Intercompany Rents	C. Lenns & M. Lenns
(7)	Change in Uncollectible Expense	C. Lenns & M. Lenns
(8)	Changes in Depreciation Expenses - Plant additions at existing & proposed rates, annual allowance for net salvage between the actual depreciation reserve	C. Lenns & M. Lenns
(9)	Changes in Taxes Other than income to reflect Changes in Payroll Tax, Gross Earnings Tax and STAS recoveries	C. Lenns & M. Lenns
(10)	Calculation of Income Tax Expense	C. Lenns & M. Lenns

Pike County Light And Power Company
Gas Cost of Service
For the Twelve Months Ended September 30, 2024
and the Twelve Months Ended September 30, 2025

	12 mos. Ended September 30, 2024 (1)	Difference Between Historical and Future Years: Reference (2)	Difference Between Historical and Future Years: Amount (3)	Future Year: 12 mos. Ended September 30, 2025 (4)=(1+3)	Future Year: Proposed Rate Change (5)	Future Year: As Adjusted for Add'l Revenue (6)
Operating Revenues:						
Sales of Gas - Base Rate Revenue	$ 2,141,300	(1a)	116,500	$ 2,257,800	$ 905,900	$ 3,163,700
Other Operating Revenues	3,900	(1b)	(2,500)	1,400	-	1,400
Total Operating Revenues	2,145,200		114,000	2,259,200	905,900	3,165,100
Operating Expenses:						
Purchased Gas Expense	1,145,900	(2)	(10,900)	1,135,000	-	1,135,000
Other Operation and Maintenance Expense	634,200	(3a)	17,400	694,100	2,500	696,600
		(3b)	20,000			
		(4)	13,500			
		(5)	9,400			
		(6)	7,800			
		(7)	(8,200)			
Depreciation & Amortization Expense	208,200	(8a)	124,900	333,100	-	333,100
		(8b)	-			
Taxes other than Income	24,700	(9)	3,000	27,700	-	27,700
Total Operating Expenses	2,013,000		176,900	2,189,900	2,500	2,192,400
Operating Income Before Income Taxes:	132,200		(62,900)	69,300	903,400	972,700
State Income Tax	(29,800)	(10)	(26,200)	(56,000)	72,200	16,200
Federal Income Tax	(72,000)	(10)	(63,400)	(135,400)	174,600	39,200
Operating Income after Taxes	$ 234,000		$ 26,700	$ 260,700	$ 656,600	$ 917,300
Rate Base	$ 7,003,300		$ 3,675,742	$ 10,679,042	$ -	$ 10,679,042
Rate of Return	3.34%			2.44%		8.59%

Pike County Light And Power Company
Calculation of Gas Revenue Requirement
For the Twelve Months Ended September 30, 2025

	Amount
Rate Base at September 30, 2025	$ 10,679,042
x Rate of Return at September 30, 2025	8.59%
Total Return Required	917,330
Total Earned Return (Per Exhibit G-4, Summary, Page 1 of 3)	260,700
Addition Return Required	656,630
Multiplied by Retention Factor*	1.3796
Total Revenue Requirement	$ 905,892
Rounded	$ 905,900

* Retention Factor:

Additional Revenue	100.0000	$ 905,900
Less: Revenue Taxes -- N/A	-	-
Less: Uncollectibles	0.280	2,500
	99.7200	903,400
Less: State Income Tax @ 7.99%	7.9676	72,200
	91.7524	831,200
Less: Federal Income Tax @ 21%	19.2680	174,600
Retention Factor	72.484	$ 656,600
	1.0000	
	0.7248	
	1.3796	

Pike County Light And Power Company
Changes in Gas Cost of Service
For the Year Ended September 30, 2025

Adjustment Number	Description	Amount
(1a)	Changes In billed revenue to reflect forecast sales	$ 116,500
(1b)	Change in Other Operating Revenues	(2,500)
(2)	Change to cost of purchased gas cost to match forecast recoveries	(10,900)
(3a)	Changes in Operations and Maintenance Expenses to reflect increases in Wages and Salaries	17,400
(3b)	Changes in Operations and Maintenance Expenses to reflect Additional Employee Positions	20,000
(4)	Changes in Operation and Maintenance Expense to Reflect Estimated Payroll Ancillary Costs -- Health Insurance, Workers Comp, 401K Match	13,500
(5)	Changes in Operation and Maintenance Expenses to reflect amortization of rate case costs	9,400
(6)	Changes in Operation and Maintenance Expense - Intercompany Administrative & Operating Charges	7,800
(7)	Change in Uncollectible Expense	(8,200)
(8a)	Changes in Depreciation Expense -- At Existing Rates	124,900
(8b)	Changes in Depreciation Expense - Annual allowance for Net Salvage / Amortization of Reserve Deficiency Case R-2008-2046520	-
(9)	Changes in Taxes Other than income to reflect Changes in Payroll Tax, Realty and Gross Earnings Tax	3,000
(10)	Calculation of Income Tax Expense - Per Books Test Year Normalize Income tax for Out of Period Adjustments & Interest Synchronization	
	- State Income Tax Adjustments	(26,200)
	- Federal Income Tax Adjustments	(63,400)

Pike County Light And Power Company
Statement in Support of Change No. (1a)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Changes In billed and unbilled revenue to reflect forecast sales and revenues at current rates.		Rounded
Revenues - Twelve Months Ended September 30, 2025 (a)		
Base Revenue	$ 140,685	
Delivery Revenue	884,160	
DSIC Revenue	97,786	
Rider Revenue (GCR)	1,134,943	
Billed Revenues - Twelve Months Ended September 30, 2025 (a)	$ 2,257,574	$ 2,257,574
Base Revenue	$ 135,453	
Delivery Revenue	757,798	
DSIC Revenue	101,956	
Rider Revenue (GCR)	1,145,888	
- Twelve Months Ended September 30, 2024 (b)	$ 2,141,096	$ 2,141,100
Net increase in Revenues	$ 116,478	$ 116,500

Sales Volumes (CCF)

	Customers	CCF's
Forecast - 12 Months Ended 09/30/2025	1,420	1,526,104
Actual - 12 Months Ended 9/30/2024	1,366	1,312,666
Total Increase	54	213,438
% Increase	4.0%	16.3%

(a) See 2025 Board approved forecast
(b) See Exhibit G-4, Summary, Page 1 of 3

Pike County Light And Power Company
Statement in Support of Change No. (1b)
To Adjust For Other Operating Revenues
For the Twelve Months Ended September 30, 2025

Other Operating Revenues	Twelve Months Ended September 30, 2024	Twelve Months Ended September 30, 2025	Net Change
Late Payment Charge-Gas	6,301	$ 3,775	$ (2,526)
Total Other Gas Revenues	6,301	3,775	(2,526)
Change in Other Operating Revenues			$ (2,526)
Rounded (Change 1b)			**$ (2,500)**

Pike County Light And Power Company
Statement in Support of Change No. (2)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2024 and September 30, 2025

Exhibit G-4
Schedule 2

Change to cost of purchase gas to match cost of gas in revenues - Adjustment 1	Twelve Months Ended 9/30/2024	Twelve Months Ended 9/30/2025		Net Change
Purchased Gas Expense *	$ 1,145,888	$ 1,134,943	*	$ (10,945)
Net increase in Gas Costs				$ (10,945)
Rounded - Change No. 2				**$ (10,900)**

* See G-4, Schedule 1 - Purchased Gas Costs match Gas Cost Recoveries

Pike County Light And Power Company
Statement in Support of Change No. (3a)
To Gas Operation and Maintenance Expense
Wage and Salary Increases
For the Twelve Months Ended September 30, 2025

Wage and Salary Increases				
- Pike Gas Payroll Expense for Twelve Months Ended September 30, 2024	$	249,347		
- Administrative Payroll allocated from Corning Gas Corporation		24,920		
- Total Gas Payroll Expense	$	274,267		
- Gas Payroll excluding May 2024 Wage Increase	$	263,296		
- Annualization of May 2024 Wage & Salary Increases (4% x 7 month / 12 months)				6,144
- Total Gas Payroll Expense (see above	$	274,267		
- Plus annualization of May 2024 Wage Increases (4% x 3 month / 12 months)		6,144		
Annualized Test Year Wages	$	280,410		
- October 2025 Wage Increase (4%)				11,216
Wage & Salary Wage Increases			$	17,360
Rounded			$	17,400

Pike County Light And Power Company
Statement in Support of Change No. (3b)

Additional Employee Positions
For the Twelve Months Ended September 30, 2025

Material Management Position		
Annual Salary for new position	$	240,000
Additional employee positions applicable to gas operation and maintenance expense		8.3%
Total Additional Employees Applicable to Pike Gas O&M Expense	$	20,000
Rounded Total	$	20,000

Job Title Description	Estimated Hire Date		Estimated Salary	Cost Allocated To: Pike Gas O&M		Cost Allocated To: Gas Salary
Pike - Assistant General Manager	Apr-25	$	140,000	14.3%	(a)	$20,000
Pike - Systems Planner	Apr-25		100,000	0.0%	(b)	-
		$	240,000	8.3%		$20,000

(a) Allocated on ratio of anticipated services of $50,000 electric expense, $20,000 gas expense, and $70,000 allocated capital.
(b) Allocated on ratio of $90,000 capital and $10,000 expense. This is for electric only.

Pike County Light And Power Company
Statement in Support of Change No. (4a)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit G-4
Schedule 4

Change in Operation and Maintenance Expenses to Reflect the estimated increase in Payroll Ancillary Costs (Health Insurance & Workers Compensation)

Pike Wage Increase and Annualization	$	17,400		
Salary and wages for additional employee(s)		20,000		
Total increase in wages	$	37,400		
x Test Year 401K Pension Match Rate		2.54%	$	950
x Test Year Health & Life Insurance Rate		22.02%		8,234
s Test Year Workers Compensation Rate		11.49%		4,299
Total Benefit Costs			$	13,483
Rounded Total			$	13,500

Pike County Light And Power Company
Statement in Support of Change No. (5)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit G-4
Schedule 5

Amortization of Estimated Outside Rate Case Expense

Estimated New Rate Case Legal Fees & Expenses	$ 250,000
2025 Percent Applicable to Gas	15%
Estimated New Rate Case Legal Fees & Expenses applicable to Gas	37,500
/ Amortization Period - Years	4
Annual Rate Case Expense	$ 9,375
Rounded	$ 9,400

Pike County Light And Power Company
Statement in Support of Change No. (6)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit G-4
Schedule 6

Intercompany Administrative & Operating Charges		
Intercompany allocations (excl. Payroll, Benefits, & Workers' Comp.) charged to O&M Expense for the Twelve Months Ended September 30, 2024	$	780,177
x CPI General Inflation Factor		1.00%
Net Change in Intercompany Expense	$	7,802
Rounded Total	$	7,800

Pike County Light And Power Company
Statement in Support of Change No. (7)
To Gas Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit G-4
Schedule 7

Uncollectible Accounts Expense	
Operating Revenues Before Rate Change -- Twelve Months Ending September 30, 2025	$ 2,257,800
Uncollectible write-offs / revenues -- Twelve Months Ending September 30, 2024	0.28%
	$ 6,322
Less: Uncollectible Expense reflected in Operation And Maintenance Expense for the Twelve Months Ending September 30, 2025	
FERC 9040	14,475
Net Change in Uncollectable Expense	$ (8,153)
Rounded Total	$ (8,200)

Pike County Light And Power Company
Statement in Support of Change No. (8a)
To Depreciation Expense
For the Twelve Months Ended September 30, 2025

	Amount			
	Gas Dist. Plant	Common Gen'l Plant Allocated	Total Gas	Adjustment
Gas Plant in Service				
At September 30, 2024 Per Exhibit G-3, Summary	7,193,512	219,580	7,413,092	
Less Acquisition Adjustment	-	-	-	
September 30, 2024 Plant In Service Balance	7,193,512	219,580	7,413,092	
Less: Non-Depreciable Plant Per Exhibit G-4, Page 3 of 4	-	(46,650)	(46,650)	
Depreciable Plant at September 30, 2024	7,193,512	172,930	7,366,442	
Additions - October 1, 2024 thru September 30, 2025				
Distribution - Completed CWIP at 9/30/2025	453,042	-	453,042	
Distribution / General Additions Plant	2,500,000	90,000	2,590,000	
Additions - October 1, 2025 thru March 31, 2026				
Distribution / General Additions	1,250,000	30,000	1,280,000	
Total Additions	4,203,042	120,000	4,323,042	
Retirements - October 1, 2024 thru September 30, 2025				
Distribution / General Plant	(121,600)	(34,600)	(156,200)	
Retirements - October 1, 2025 thru March 31, 2026				
Distribution / General Plant	(60,800)	(17,300)	(78,100)	
Total Retirements	(182,400)	(51,900)	(234,300)	
Gas Depreciable Plant at September 30, 2025	11,214,154	241,030	11,455,185	
x Existing Composite Book Depreciation Rate	2.629%	15.866%	2.908%	
Calculated Accruals to Depreciation Reserves				
For The Twelve Months Ended September 30, 2025	**294,820**	**38,242**	**333,062**	
Less: 12 Months Ending September 30, 2024 (See G-4, Summary)	153,739	54,422	208,161	
Increase In Depreciation Expense	141,081	(16,180)		**$ 124,902**
Rounded Change (8)				**$ 124,900**

Depreciation Reserve Calculation	Gas	100% Common	Gas Common
September 30, 2024 Plant	$ 7,193,512	$ 1,152,869	$ 172,930
Plus 50% of Additions / Retirements 10/24 - 9/25	1,189,200	184,667	27,700
Depreciable Plant	$ 8,382,712	$ 1,337,536	$ 200,630
x Composite Depreciation Rate	2.629%	15.866%	15.866%
October 1, 2024 - September 30, 2025 Depreciation Accrual	$ 220,382	$ 212,213	$ 31,832
Rounded	$ 220,400	$ 212,200	$ 31,800

September 30, 2024 Plant	$ 7,193,512	$ 1,152,869	$ 172,930
Plus 100% of Additions / Retirements 10/24 - 9/25	2,378,400	369,333	55,400
50% of Additions / Retirements 10/25 - 3/26	594,600	6,350	-
Depreciable Plant	$ 10,166,512	$ 1,528,553	$ 228,330
x Composite Depreciation Rate	2.629%	15.866%	15.866%
October 1, 2024 - September 30, 2025 Depreciation Accrual	$ 267,278	$ 242,520	$ 36,227
	50%	50%	50%
October 1, 2025 - March 31, 2026 Depreciation Accrual	$ 133,639	$ 121,260	$ 18,113
Rounded	$ 133,600	$ 121,300	$ 18,100

Pike County Light And Power
Statement in Support of Change No. (12a)
To Depreciation Expense
Calculation of Gas Composite Book Depreciation Rate
For the Twelve Months Ended September 30, 2025

Gas- Distribution	September 30, 2024 Book Costs	Acquisition Adjustment	September 30, 2024 Plant Balance	Average Service Life	Annual Rate	COR & Salvage Adj.	Annual Accrual with Salvage	COMPOSITE RATES Annual	Monthly
PK - G- 374000 - LAND-EASEMENTS	744.35	-	744.35	60	1.67%	-	12.43	1.67%	0.139%
PK - G- 376000 - MAINS	4,353,729.46	-	4,353,729.46	70	1.43%	973.00	63,231.33	1.45%	0.121%
PK - G- 378000 - MEAS AND REGULA EQ	131,500.90	-	131,500.90	30	3.33%	-	4,378.98	3.33%	0.278%
PK - G- 380000 - SERVICES	1,693,811.79	-	1,693,811.79	65	1.54%	5,157.00	31,241.70	1.84%	0.154%
PK - G- 381000 - METERS	62,822.86	-	62,822.86	30	3.33%	(240.00)	1,852.00	2.95%	0.246%
PK - G- 382000 - METER INSTALLS	536,758.77	-	536,758.77	40	2.50%	(8.00)	13,410.97	2.50%	0.208%
PK - G- 382400 - METER BARS	-	-	-	40	2.50%	-	-	0.00%	0.000%
PK - G- 384000 - HOUSE REG INSTALLS	9,539.42	-	9,539.42	40	2.50%	-	238.49	2.50%	0.208%
PK - G- 385000 - INDUST MEAS/REG EQ	36,150.95	-	36,150.95	35	2.86%	-	1,033.92	2.86%	0.238%
Gas distribution Total	**6,825,058.50**	**-**	**6,825,058.50**			**5,882.00**	**115,399.82**		
Depreciable Gas distribution Total	**6,825,058.50**	**-**	**6,825,058.50**			**5,882.00**	**115,399.82**	**1.69%**	**0.141%**
Gas- General Plant Total									
PK - E- 394 & 399 - TOOLS & EXCESS RESERVE	368,453.56	-	368,453.56	5	20.00%	-	73,690.71	20.00%	1.667%
Gas- General Plant Total	**368,453.56**	**-**	**368,453.56**			**-**	**73,690.71**		
Depreciable Gas- General Plant Total	**368,453.56**	**-**	**368,453.56**			**-**	**73,690.71**	**20.00%**	**1.667%**
Total Gas	**7,193,512.06**	**-**	**7,193,512.06**			**5,882.00**	**189,090.53**		
Total Depreciable Gas	**7,193,512.06**	**-**	**7,193,512.06**			**5,882.00**	**189,090.53**	**2.629%**	**0.219%**

Pike County Light And Power
Statement in Support of Change No. (8a)
To Depreciation Expense
Calculation of Common Plant Composite Book Depreciation Rate
For the Twelve Months Ended September 30, 2025

Account	Common General Plant	September 30, 2024 Book Costs	Acquisition Adjustment	September 30, 2024 Plant Balance	Average Service Life	Annual Rate	COR & Salvage Adj.	Annual Accrual with Salvage	COMPOSITE RATES Annual	COMPOSITE RATES Monthly
303000	Intangible Asset - Trade Name (a)	311,000.00		311,000.00		(a)		-	-	-
391101	Office Furniture & Equipment	(14,709.24)		(14,709.24)	5	20.00%	-	(2,941.85)	20.00%	1.667%
391115	Office Furniture & Equipment	14,344.77		14,344.77	5	20.00%	-	2,868.95	20.00%	1.667%
391215	Office Furniture & Equipment - Miscellaneous	(77,193.06)		(77,193.06)	5	20.00%	-	(15,438.61)	20.00%	1.667%
391315	Office Furniture & Equipment - Computers	476,644.90		476,644.90	10	10.00%	-	47,664.49	10.00%	0.833%
392015	Transportation	596,945.68		596,945.68	5	20.00%	-	119,389.14	20.00%	1.667%
397101	Communication Equipment - Telephone	4,097.84		4,097.84	5	20.00%	-	819.57	20.00%	1.667%
397115	E Comm Equip-Milford Township	139,261.95		139,261.95	5	20.00%	-	27,852.39	20.00%	1.667%
398001	E Misc Equip	1,735.19		1,735.19	5	20.00%	-	347.04	20.00%	1.667%
398015	E Misc Equip - Milford Town	11,741.39		11,741.39	5	20.00%	-	2,348.28	20.00%	1.667%
	Common General Total	**1,463,869.42**	**-**	**1,463,869.42**				**182,909.39**		
	Common Depreciable General Total (excl 303000)	**1,152,869.42**	**-**	**1,152,869.42**				**182,909.39**	**15.866%**	**1.322%**
	Total Electric Common	**1,244,289.01**	**-**	**1,244,289.01**				**155,472.98**		
	Total Electric Depreciable Common	**979,939.01**	**-**	**979,939.01**				**155,472.98**	**15.866%**	**1.322%**
	Total Gas Common	**219,580.41**	**-**	**219,580.41**				**27,436.41**		
	Total Gas Depreciable Common	**172,930.41**	**-**	**172,930.41**				**27,436.41**	**15.866%**	**1.322%**

(a) **This asset is being amortized over 15 years. The annual depreciation expense of $20,733 is charged below the line to FERC account 425.**

Pike County Light And Power Company
Statement in Support of Change No. (8b)
To Depreciation Expense
For the Twelve Months Ended September 30, 2025

Gas Plant	Five Year Cumulative Net Salvage	Proposed Annual Net Salvage	Current Net Salvage Allowed	Net Change In Expense
376000 MAINS	4,865	$ 973	$ 973	$ -
378000 MEASURING AND REGULATING EQUIPMENT	-	-	-	-
380000 SERVICES	25,785	5,157	5,157	-
381000 GAS METER PURCHASES	(1,202)	(240)	(240)	-
382000 GAS METER INSTALLS	(38)	(8)	(8)	-
382400 GAS METER BAR	-	-	-	-
384000 HOUSE REGULATOR INSTALLATIONS	-	-	-	-
385000 INDUSTRIAL MEAS & REG EQUIPMENT	-	-	-	-
Total	$ 29,409	$ 5,882	$ 5,882	$ -
40 Year Amortization of Reserve Deficiency - Case R-2008-2046520 through March 2049		(900)	(900)	-
Total Adjustment		$ 4,982	$ 4,982	$ -
Rounded				$ -

Pike County Light And Power Company
Statement in Support of Change No. (9)
To Other Tax Expense
For the Twelve Months Ended September 30, 2025

Changes in Taxes Other	Actual 9/30/2024	Future Year 9/30/2025		Changes
	(1)	(2)		(3)
Payroll Taxes (FICA / Medicare)	$ 20,734	$ 23,839	*	$ 3,106
Property Taxes	3,392	3,290		(103)
State and Local Taxes	-	-		-
	$ 24,126	$ 27,129		$ 3,003
Rounded				$ 3,000

* See Exhibit G-4, Schedule 9, page 2

Pike County Light And Power Company
Statement in Support of Change No. (9)
To Taxes Other than Income
For the Twelve Months Ended September 30, 2025

Change in Taxes Other Than Income to reflect the estimated increase
in Payroll Taxes (FICA, Medicare, and Unemployment):

Pike Payroll	$	274,267
Wage Increase and Annualization		17,360
Salary and wages for additional employees		20,000
Total increase in wages	$	311,627
FICA / Medicare Rate		7.65%
Total Payroll Taxes	$	23,839
Rounded Total	$	23,800

Pike County Light And Power Company
Adjustment No. (10)
Calculation of Gas State Income Taxes
For The Twelve Months Ended September 30, 2025

	Per Books 12 Months Ended 9/30/2024	Income Tax Normalizing Adjustments	12 Months Ended 9/30/2024 (1)	Income Adjustments (2)	12 Months Ended 9/30/2025 (3) = (1) + (2)	Proposed Rate Change (4)	As Adjusted For Additional Revenue (5) = (3) + (4)
Operating Income Before Income Taxes	132,200	-	$ 132,200	$ (62,900)	$ 69,300	$ 905,900	$ 975,200
Less Interest Expense (incl amort of debt exp)	182,888	322,050	504,938	265,021	769,959	-	769,959
Other Income & Deductions (incl Donations)	3,494	(3,494)	-	-	-		-
Book Income Before FIT	(54,182)	(318,556)	(372,738)	(327,921)	(700,659)	905,900	205,241
Section I- Permanent Items:							
Add: Negative Provision for Uncollectibles	(14,475)	14,475	-	-	-	-	-
Less: Uncollectable Write-Offs (not in O&M)	-	-	-	-	-	2,500	2,500
Total	(14,475)	14,475	-	-	-	2,500	2,500
Pretax Income	(39,707)	(333,031)	(372,738)	(327,921)	(700,659)	903,400	202,741
Section II - Normalized Items:							
Add: Additional Taxable Income and Unallowable Deductions:							
Book Depreciation	208,200	-	208,200	124,900	333,100	-	333,100
Amortization of Rate Case Expenditures	-	-	-	9,400	9,400	-	9,400
Recovery of Prior Deferred Purchased Gas Cost	178,625	-	178,625	(178,625)	-	-	-
Total	386,825	-	386,825	(44,325)	342,500	-	342,500
Deduct: Non-Taxable Income and Allowable Deductions							
Tax Depreciation	255,285	-	255,285	-	255,285	-	255,285
Rate Case Expenditures	-	-	-	37,500	37,500	-	37,500
Deferral of Def. Purchased Gas Costs	(22,888)	-	(22,888)	22,888	-	-	-
Total	232,397	-	232,397	60,388	292,785	-	292,785
Federal NOL	-	-	-		-		-
Taxable Income	114,721	(333,031)	(218,310)	(432,634)	(650,944)	903,400	252,456
State Tax Adjustments	-	-	-	-	-	-	-
Adjusted Taxable Income	114,721	(333,031)	(218,310)	(432,634)	(650,944)	903,400	252,456
x State Income Tax @ 7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%	7.99%
Current Tax Provision	9,166	(26,609)	(17,443)	(34,567)	(52,010)	72,200	20,190
Deferred Income Tax Dr.- Account 410	18,569	-	18,569	4,825	23,394	-	23,394
Deferred Income Tax Cr.- Account 411	(30,907)	-	(30,907)	3,542	(27,366)	-	(27,366)
	(3,173)	(26,609)	(29,782)	(26,201)	(55,983)	72,200	16,217
			12,339				3,972
Rounded	$ (3,200)	$ (26,600)	$ (29,800)	$ (26,200)	$ (56,000)	$ 72,200	$ 16,200

Pike County Light And Power Company
Adjustment No. (10)
Calculation of Gas Income Taxes
For the Twelve Months Ended September 30, 2025

	Per Books 12 Months Ended 9/30/2024	Adjustments	12 Months Ended 9/30/2024 (1)	Proposed Rate Change (2)	12 Months Ended 9/30/2025 (3) = (1) + (2)	Proposed Rate Change (4)	As Adjusted For Additional Revenue (5) = (3) + (4)
State Taxable Income (G-4, Sched 10, Pg 1)	$ 114,721	$ (333,031)	$ (218,310)	$ (432,634)	$ (650,944)	$ 903,400	$ 252,456
Less: State Income Tax	3,173	26,609	29,782	26,201	55,983	(72,200)	(16,217)
Federal Tax Adjustments	-	-	-	-	-	-	-
Adjusted Taxable Income	117,894	(306,422)	(188,528)	(406,433)	(594,961)	831,200	236,239
* Federal Income Tax Rate	21%	21%	21%	21%	21%	21%	21%
Current Federal Income Tax	$ 24,758	$ (64,349)	$ (39,591)	$ (85,351)	$ (124,942)	$ 174,600	$ 49,610
Deferred Federal Income Tax Applicable To:							
Book Depreciation	(43,722)	-	(43,722)	(26,229)	(69,951)	-	(69,951)
Amortization of Rate Case Expenditures	-	-	-	(1,974)	(1,974)	-	(1,974)
Recovery of Prior Deferred Purchased Gas Cost	(37,511)	-	(37,511)	37,511	0	-	0
Tax Depreciation	53,610	-	53,610	-	53,610		53,610
Rate Case Expenditures	-	-	-	7,875	7,875		7,875
Deferral of Def. Purchased Gas Costs	(4,806)	-	(4,806)	4,806	(0)		(0)
Total	11,292	-	11,292	50,193	61,485	-	61,485
Summary of Federal Income Taxes:							
Current Federal Income Tax - 409	24,758	(64,349)	(39,591)	(85,351)	(124,942)	174,600	49,658
Deferred Federal Income Tax Dr - 410	48,803	-	48,803	12,681	61,485	-	61,485
Deferred Federal Income Tax Dr - 411	(81,233)	-	(81,233)	9,308	(71,925)	-	(71,925)
Deferred FIT Adjustments	-	-	-	-	-	-	-
Total	$ (7,672)	$ (64,349)	$ (72,021)	$ (63,361)	$ (135,382)	$ 174,600	$ 39,218
			32,430				10,440
Rounded	$ (7,700)	$ (64,300)	$ (72,000)	$ (63,400)	$ (135,400)	$ 174,600	$ 39,200

Pike County Light And Power Company
Adjustment No. (10)
Calculation of Gas Income Taxes
For the Twelve Months Ended September 30, 2025

	Per Books 12 Months Ended 9/30/2024	Adjustments	12 Months Ended 9/30/2024 (1)	Proposed Rate Change (2)	As Adjusted For Additional Revenue (3) = (1) + (2)
Rate Base	$ 7,003,300	$ -	$ 7,003,300	$ 3,675,742	$ 10,679,042
Interest Component of Capitalization	2.61%	4.60%	7.21%	7.21%	7.21%
Interest Expense	$ 182,888	$ 322,050	$ 504,938	$ 265,021	$ 769,959
Rounded	$ 182,900	$ 322,100	$ 504,900	$ 265,000	$ 770,000

This adjustment is related to State and Federal Income Taxes

Pike County Light And Power Company
Index of Schedules
Gas Sales and Revenues

Exhibit G-5

Schedule	Title of Schedule	Witness
(1)	Historic Gas Sales by Service Classification	C. Lenns & M. Lenns
(2)	Future Gas Sales by Service Classification	C. Lenns & M. Lenns
(3)	Historic Gas Revenue by Service Classification	C. Lenns & M. Lenns
(4)	Future Gas Revenue by Service Classification	C. Lenns & M. Lenns
(5)	Forecasted Delivery Volumes (CCF)	C. Lenns & M. Lenns
(6)	Forecasted Gas Total Sales Revenues	C. Lenns & M. Lenns

PIKE COUNTY LIGHT AND POWER COMPANY

Gas Sales (CCF)
For the 12 Months Ended September 30, 2024

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Billed Sales													
SC1	41,969	122,034	133,222	189,163	158,808	105,021	90,051	33,299	18,537	18,755	17,606	18,699	947,165
SC2	22,751	40,985	43,303	59,374	50,802	34,622	34,467	18,923	14,372	15,425	14,853	15,622	365,500
Total	64,721	163,020	176,525	248,537	209,611	139,643	124,518	52,222	32,909	34,180	32,459	34,322	1,312,666

PIKE COUNTY LIGHT AND POWER COMPANY

Gas Sales (CCF)
For the Future Test Year Ended September 30, 2025

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Billed Sales													
SC1	49,932	130,157	155,321	222,599	189,839	140,736	103,085	47,108	19,998	19,562	18,363	19,878	1,116,578
SC2	26,098	42,288	49,060	67,877	58,464	42,398	37,732	23,049	14,832	15,919	15,328	16,480	409,525
Total	76,030	172,445	204,381	290,476	248,303	183,135	140,817	70,157	34,830	35,480	33,691	36,358	1,526,104

Exhibit G-5
Schedule 3

PIKE COUNTY LIGHT AND POWER COMPANY

Gas Revenues ($)
For the 12 Months Ended September 30, 2024

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Billed Revenue													
SC1	$ 89,360	$ 208,093	$ 220,658	$ 308,823	$ 261,087	$ 176,247	$ 152,664	$ 63,252	$ 40,065	$ 40,325	$ 38,652	$ 40,249	$ 1,639,476
SC2	37,800	56,426	58,050	78,830	67,758	46,741	46,344	26,020	20,051	21,352	20,629	21,820	501,818
Total	$ 127,159	$ 264,519	$ 278,708	$ 387,653	$ 328,845	$ 222,988	$ 199,007	$ 89,272	$ 60,116	$ 61,677	$ 59,281	$ 62,069	$ 2,141,294

Exhibit G-5
Schedule 4

PIKE COUNTY LIGHT AND POWER COMPANY

Gas Revenues ($)
For the Future Test Year Ended September 30, 2025

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Rate Revenue													
SC1	$ 42,891	$ 94,798	$ 111,078	$ 154,579	$ 133,414	$ 101,680	$ 77,326	$ 41,149	$ 23,628	$ 23,346	$ 22,596	$ 23,558	$ 850,044
SC2	11,681	17,817	20,427	27,473	23,947	17,777	15,930	10,510	7,038	7,383	7,175	7,644	174,801
Subtotal	54,572	112,616	131,505	182,052	157,360	119,458	93,256	51,659	30,666	30,728	29,771	31,202	1,024,845
DSIC Revenue													
SC1	4,544	6,264	13,284	10,273	10,936	11,372	5,491	4,504	3,243	2,606	2,420	2,633	77,569
SC2	1,301	1,525	2,307	2,005	2,134	2,219	1,440	1,480	1,548	1,317	1,467	1,473	20,217
Subtotal	5,845	7,789	15,591	12,277	13,070	13,592	6,930	5,983	4,791	3,923	3,887	4,106	97,786
GCR Revenue													
SC1	48,704	64,736	128,991	102,173	111,124	111,109	59,840	50,660	38,870	30,017	27,414	29,539	803,176
SC2	21,037	24,291	36,283	31,563	34,089	35,302	23,194	24,770	26,982	22,771	25,899	25,587	331,767
Subtotal	69,740	89,027	165,274	133,736	145,212	146,411	83,034	75,430	65,853	52,789	53,312	55,126	1,134,943
Total Billed Revenue													
SC1	96,138	165,798	253,353	267,026	255,474	224,162	142,657	96,312	65,741	55,969	52,430	55,730	1,730,788
SC2	34,019	43,633	59,017	61,040	60,169	55,298	40,563	36,760	35,569	31,471	34,541	34,704	526,786
Subtotal	$ 130,158	$ 209,432	$ 312,370	$ 328,066	$ 315,643	$ 279,460	$ 183,220	$ 133,072	$ 101,310	$ 87,440	$ 86,971	$ 90,434	$ 2,257,574

PIKE COUNTY LIGHT & POWER COMPANY
Gas Sales (CCF)
For the Twelve Months Ending September 30, 2025

Column No.		1	2	3
Line No.	**Description**	**SC 1 Residential**	**SC 2 Commercial**	**Total Billed**
1	Actual billed delivery volumes 12 months ended September 30, 2024	947,165	365,501	1,312,666
2	Weather Adjustment	123,377	31,326	154,703
3	Forecast Increase in Customers	46,036	12,698	58,734
4	**Forecasted Delivery Volumes** **12 months ended September 30, 2025**	1,116,578	409,525	1,526,104

EXHIBIT G-5
Schedule 6

PIKE COUNTY LIGHT & POWER COMPANY
Forecasted Gas Total Sales Revenue
For the Twelve Months Ending September 30, 2025

Column No.		1	2	3	4	5	6	7
Line No.	Service Classification	Gas Delivery Volumes CCF	Gas Customers	Base Revenue ($000)	DSIC Revenue ($000)	Delivery Revenue ($000)	Rider Revenue ($000)	Total Sales Revenue ($000)
	Billed Delivery							
1	SC 1 - Residential	1,116,578	1,334	$ 128,064	$ 77,569	$ 721,980	$ 803,176	**$ 1,730,788**
2	SC 2 - Commercials	409,525	86	12,621	20,217	162,180	331,767	**526,786**
	Total Billed Delivery	**1,526,104**	**1,420**	**$ 140,685**	**$ 97,786**	**$ 884,160**	**$ 1,134,943**	**$ 2,257,574**

Pike County Light & Power Co.
330 West William Street
Corning, NY 14830

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1. Notices to customers of the proposed increases was mailed to all Pike County Light & Power gas customers on December 30, 2024;
2. Notice of a Rate Increase has been posted in the Company's offices at 105 Schneider Lane, Milford, PA 18337 on December 30, 2024. This notice is the same notice as the notice mailed to customers;
3. Notice of a Rate Increase for Pike County Light & Power Gas was delivered on behalf of the Company to two local newspapers, the Pike County Courier (Straus News) and the Pike County Dispatch, for publication, on December 30, 2024; and
4. Notice of a Rate Increase that was posted on the Company's website www.pclpeg.com on December 30, 2024. This notice is the same notice that was mailed to customers.

I, Charles Lenns, Senior Vice President and Chief Financial Officer, on behalf of Pike County Light & Power Company, hereby state that the facts set forth in the foregoing document 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 hearing in this matter. This verification is made subject to the penalties of 18 Pa.C.S.s. § 4904 relating to unsworn falsification to authorities.

____
Charles Lenns
Senior Vice President and Chief Financial Officer
Pike County Light & Power Company

Dated: December 30, 2024

Pike County Light & Power Co.
330 West William Street
Corning, NY 14830

NOTICE OF PROPOSED GAS RATE CHANGES

12/30/2024

To Our Gas Customer

Pike County Light and Power Company, Inc. is filing a request with the Pennsylvania Public Utility Commission (PUC) to increase your Gas rates as of October 1, 2025. This notice describes the company's rate request, the PUC's role, and what actions you can take.

Pike County Light and Power Company, Inc. has requested an overall rate increase of $905,900 per year, if the company's entire request is approved, customer bills would increase as follows:

- Residential heating customers using 80 CCF would increase from $135.78 to $196.08 per month, or by 44.4% including estimated gas costs.
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To find out your customer class or how the requested increase may affect your gas bill, contact Pike County Light & Power Company at (855) 855-2050. The rates requested by the company may be found in TARIFF SUPPLEMENT NO. 127 TO TARIFF-GAS PA PUC NO. 6. You may examine the material filed with the PUC which explains the requested increase and the reasons for it. A copy of this material is kept at Pike County Light & Power's office.

The state agency that approves rates for public utilities is the PUC. The PUC will examine the requested rate increase and can prevent existing rates from changing until it investigates and/or holds hearings on the request. The company must prove that the requested rates are reasonable. After examining the evidence, the PUC may grant all, some, or none of the request or may reduce existing rates. The PUC may change the amount of the rate increase or decrease requested by the utility for each customer class. As a result, the rate charged to you may be different than the rate requested by the company and shown above. There are three ways to challenge a company's request to change its rates:

1. You can file a formal complaint. If you want a hearing before a PUC judge, you must file a formal complaint. By filing a formal complaint, you assure yourself the opportunity to take part in hearings about the rate increase request. All complaints should be filed with the PUC before

Pike County Light & Power Co.
330 West William Street
Corning, NY 14830

February 28, 2025. If no formal complaints are filed, the Commission may grant all, some or none of the request without holding a hearing before a judge.

2. You can send the PUC a letter telling why you object to the requested rate increase. Sometimes there is information in these letters that makes the PUC aware of problems with the company's service or management. This information can be helpful when the PUC investigates the rate request. Send your letter or formal complaint form to the Pennsylvania Public Utility Commission, Post Office Box 3265, Harrisburg PA 17105-3265.

3. You can be a witness at a public input hearing. Public input hearings are held if the Commission opens an investigation of the company's rate request and if there is a large number of customers interested in the case. At these hearings you have the opportunity to present your views in person to the PUC judge hearing the case and the company representatives. All testimony given "under oath" becomes part of the official rate case record. These hearings are held in the service area of the company.

Pike County Light & Power Company

Pike County Light & Power Co.
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Corning, NY 14830

PUBLIC NOTICE GAS RATES

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The company has requested the rate increase because it has incurred and will realize increased operating expenses since its last rate change in 2021. These expenses include the financing of investments in new and replacement infrastructure, as well as increased operating costs due to normal operating conditions and other regulatory demands to meet customer service and reliability requirements. Customers can contact the company at (855) 855-2050 to get further information on the proposed increases, or to find out what action they may take.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	DOCKET NO. R-2024-3052357
	:	
Pike County Light & Power Company (gas)	:	

Pike County Light and Power Company

Statement No. 3

Direct Testimony of

Ed Verbraak

Q. Please state your name and business address.

A. My name is Ed Verbraak and my business address is One Hundred Five Schneider Lane, Milford, Pa 18337.

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

A. I am employed by Pike County Light & Power Company ("Pike" or the "Company") as the Company's General Manager. . In this position I am responsible for all operations at Pike.

Q. Please provide your educational background and professional experience.

A. I have a Bachelor's of Engineering in Mechanical Engineering from Stevens Institute of Technology and a Master's of Business Administration in Finance and Economics from Pace University. Prior to joining Pike, I was employed for 34 years by Consolidated Edison Company of New York, and its wholly owned subsidiary, Orange & Rockland Utilities Corporation in various capacities, including, but not limited to, customer service, new construction, control center operations, electric operations, emergency management, and electrical engineering.

Q. Have you previously sponsored testimony before the Pennsylvania Public Utility Commission ("PAPUC")?

A. Yes, in 2022 I provided testimony in both Pike's electric and gas DISC filings.

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

A. I will provide an overview of Pike's gas system that serves the Matamoras and Westfall areas in Pennsylvania and I will discuss Pike's gas main replacement program and planned system pressure upgrades as presented in the Company's Distribution Gas Long Term Infrastructure Improvement Plan ("LTIIP") that was submitted to the PAPUC in 2019 and approved by order entered June 13, 2019 at Docket No. P-2019-3007304.

Q. Please provide an overview of Pike's gas system that serves the Matamoras, Pennsylvania area.

A. The Pike natural gas distribution system was installed over a one-hundred-year time frame to where it is today. The system was expanded in spurts of construction and customer growth throughout Matamoras Borough and eventually into Westfall Township. The system operates primarily on low pressure which has advantages, but also has limitations on expansion and reliability.

Q. Please continue with your description of the Pike gas system.

A. Pike serves approximately 1,400 residential and commercial gas customers in the Matamoras and Westfall areas. The system consists of 21.58 miles of medium and low pressure distribution main ranging in diameter from 2" through 8". The gas system is supplied from Port Jervis, New York via a 6" cathodically protected 55 pounds per square inch gauge ("psig") main. The 55 psig system continues through many parts of Matamoras and Westfall served by Pike. The low-pressure system in the older parts of Matamoras operates at a utilization pressure of from 6 to 8 inches' water column, which is equivalent to approximately one quarter of a psig. This is the same pressure that is used by customers for normal household appliances so there are no service regulators, and the meters are generally indoors to prevent freezing problems. The Company's low-pressure system is supplied by three distribution regulator stations supplied from the 55 psig system. The 55 psig system consists of approximately 5.84 miles of plastic main, 0.5 miles of cathodically protected steel gas main, and approximately 0.2 miles of bare steel main. The low-pressure system consists of 6.9 miles of cast iron main, 3.4 miles of bare steel main, 2 miles of cathodically protected steel main and approximately 1 mile of plastic main.

Q. How does Pike manage its gas facility assets?

A. The Company closely monitors the performance of its in service gas infrastructure. The Company focuses on recognizing signs of deterioration in the integrity of cast iron main and bare steel main through tracking leak performance by area, age and materials, and water infiltration into low-pressure systems. The Company's gas system has been operating without major incident with the exception of water infiltration into a cast iron main and service in low lying area.

Q. Was the water infiltration into a cast iron main and service in low a lying area a one-time occurrence or is this a recurring problem in the system?

A. Water infiltration is a recurring condition in a specific area of the gas distribution system that was installed prior to the Company's ownership.

Q. What is Pike's approach to improve its aging infrastructure?

A. In 2019, Pike submitted its LTIIP to maintain system reliability and to replace aging infrastructure as assets reach the end of their service lives. Pike filed an 11-year plan to provide a program to complete its gas distribution system upgrade. .

Pike selected and prioritized three programs over the 11 years, including a main replacement program, regulator station replacement/overhaul, and a metering upgrade program. These programs are all based on sound engineering and Northeast Gas Association ("NGA") recognized practices, Federal Department of Transportation ("DOT") Codes and Standards, and Pike Operating and Maintenance Standards and Practices.

The three programs address Pike's areas of aging infrastructure, which is approaching useful life, improving system safety, and mitigating over time the risk of leaks and higher maintenance. Therefore, an accelerated, proactive replacement program is a prudent, reasonable, and necessary course of action. Such an accelerated program was listed as one of the "highest priority" in the Commission's last management audit of Pike. *Focused Management and Operations Audit of Pike County Light and Power Company and Leatherstocking Gas Company LLC*, Docket Nos. D-2017-2584891 et al., Audit at 54-56 (issued Nov. 2017).

Q. What capital projects did Pike construct in the last year?

A. In 2023, Pike completed its Ave K and Delaware Drive LTIIP conversion projects. In 2024, Pike completed its Avenue I LTIIP conversion projects (10th to 3rd) and (3rd to Delaware Dr). This totals 9,964' of retired main and 4569' of installed main with 73 services. Pike also connected mains on 3rd Street and Delaware Drive along Avenue H. This totaled 900' of main installed, with nothing retired.

Q. What gas projects is Pike currently working on?

A. In 2025, Pike will be completing Avenues O and P LTIIP conversion projects (from 5th street to Delaware Dr) and Bertha Street (Flood zone - smaller diameter pipe west of 10th Street)

Q. Are there other benefits to the system from replacing cast iron and bare steel main?

A. Yes. The main replacement program includes service renewals, service regulator installations, and moving inside gas meters to outside a residence or commercial building. Excess flow valves are installed on every service as well to automatically shut-off the gas flow if there is damage to the service line or in the event of a fire, thereby reducing the amount of gas going to a break in the gas piping at the building, and minimizing risk of personal injury and/or property damage..

Q. What is the annual cost of the replacement program?

A. The annual cost of the replacement program is estimated to be $1.353 million for 2025 and $2.059 million for 2026 as set forth in Exhibit G-3, Schedule 10.

Q. Please describe the major plant expenditures that Pike plans to complete over the next five years.

A.

LTIIP Project	Retired	Installed	Year
Ave O & P (4th - 1st), start Ave N (1st-3rd)	2,680	2,494	2025
Flood zone - smaller diameter pipe west of 10th Street	3,758	3,288	2025
Flood Zone/4" & 6" CI & 6" MJ, 2" WI - Ave N (10th - 4th)	3,371	2,382	2026
Flood Zone/4" & 6 CI & 6" MJ & BS - Ave M (10th - 4th)	3,252	3,402	2026
Flood Zone/4" & 6" CI & 6" MJ & BS -Ave L (9th-4th)	3,902	4,027	2027
Pond Dr-Ave B from 1st-2nd st/mostly 2" & 4" BS	2,684	2,684	2027
Ave B - Ave D from Delaware - 4th St/mostly 6" MJ & BS	3,647	3,547	2028
Ave E from 6th-3rd St/2", 3", 4" various pipe material	3,161	2,530	2028
Ave F from 6th-3rd st/2", 3", 4" various pipe material	2,991	3,791	2029
Ave G from 6th - 1st st/ mostly 2" WI, 2", 3" BS	2,912	2,912	2029
Flood Zone/4" & 6"CI & 4" & 6" BS - Penn Ave (10th - 1st)	4,521	4,831	2030
Tie Delaware Ave/Penn Ave to Ave O & P along 1st St	3,068	3,268	2030

Q. Are you proposing any staffing changes in Pike?

A. Yes, Pike has a relatively small staff in Pennsylvania, and we need an additional person to help support our workload. As shown on Exhibit G-4, Schedule 3, page 2 of 2, the Company has plans to hire an Assistant General Manager, along with a Systems Planner for Pike Electric. The Assistant General Manager will perform several tasks including having direct supervision of and coordination of gas planning work, scheduling and assigning all work to the Company's contractors, updating project statuses in the corporate work management system ("WMS"), prepare and file all gas related Public Utility Commission Report filings and coordinate with the General Manager on all updates for the gas long term infrastructure improvement plans. The estimated annual wages for this employee would be $140,000. 14.3 percent of the expense portion of the salary for this position ($20,000) was allocated to Pike's gas operations based on the current gas vs. electric customer split. $50,000 will be allocated to Pike Electric expense, and the remaining $70,000 will be allocated to capital between electric and gas at the 85/15 split. The second position is a Systems Planner, which will be allocated 100% to Pike Electric.

Q. Does that conclude your testimony?

A. Yes, it does. I reserve the right to update or amend my testimony.

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Charles Lenns
Senior Vice President and Chief Financial Officer
Pike County Light & Power Company

Dated: December 30, 2024

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330 West William Street
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12/30/2024

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<u>Pike County Light and Power Company, Inc.</u>

Gas Rate Case Filing Docket No. R-2024-3052357

Data Responses to 52 Pa. Code Sections 53.52

(1) The specific reasons for each change.

Response: Pike is not earning an adequate return on equity to finance its construction budget.

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

Response: Pike serves approximately 1,366 gas customers.

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

Response: All SC1,and SC2 customers will be impacted by the rate change.

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

Response: See Exhibit G-8.

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

Response: See Exhibit G-4, Summary.

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

Response: Service levels will not change, but Pike's ability to raise capital at a lower cost will improve.

(7) A list of factors considered by the utility in its determination to make the change.

Response: The Company seeks new rates to respond to the continued increase in the cost of system improvements needed to ensure safe and reliable gas service to its customers, and to respond to inflationary pressures on operating expenses such as salaries and wages, insurance costs, and cybersecurity improvements.

(8) Studies undertaken by the utility in order to draft its proposed change.

Response: N/A.

(9) Plans the utility has for introducing or implementing the changes with respect to its ratepayers.
Response: General rate increase utilizing the Cost of Service Study included as Exhibit G-6.

(10) Commission orders or rulings applicable to the filing.

Response: N/A .

Pike County Light and Power Company, Inc.

Gas Rate Case Filing Docket No. R-2024-3052357

Data Responses to 52 Pa. Code Sections 53.52

Part (b) Whenever a public utility files a tariff, revision or supplement which will increase or decrease the bills to its customers, it shall submit in addition to the requirements of subsection (a), to the Commission, with the tariff, revision or supplement, statements showing the following:

(1) The specific reasons for each increase or decrease.

Response: A delivery rate Increase is necessary to provide a reasonable rate of return to the Company's investors.

(2) The operating income statement of the utility for a 12-month period, the end of which may not be more than 120 days prior to the filing.

Response: Please refer to Exhibit G-1, Schedules 3 and 4.

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

Response: Please refer to Exhibit G-5, Schedule 6.

(4) A calculation of the total increases, in dollars, by tariff subdivision, projected to an annual basis.

Response: Please refer to Exhibit G-8.

(5) A calculation of the number of customers, by tariff subdivision, whose bills will be decreased.

Response: None.

(6) A calculation of the total decreases, in dollars, by tariff subdivision, projected to an annual basis.

Response: N/A.

Part (c) If a public utility files a tariff, revision or supplement which it is calculated will increase the bills of a customer or a group of customers by an amount, when projected to an annual basis, exceeding 3% of the operating revenues of the utility—subsection (b)(4) divided by the operating revenues of the utility for a 12-month period as defined in subsection (b)(2)—or which it is calculated will increase the bills of 5% or more of the number of customers served by the utility—subsection (b)(3) divided by subsection (a)(2)—it shall submit to the Commission with the tariff, revision or supplement, in addition to the statements required by subsections (a) and (b), all of the following information:

(1) A statement showing the utility's calculation of the rate of return earned in the 12-month period referred to in subsection (b)(2), and the anticipated rate of return or operating ratio to be earned

when the tariff, revision or supplement becomes effective. The rate base used in this calculation shall be supported by summaries of original cost for the rate of return calculation. When an

operating ratio is used in this calculation, it shall be supported by studies of margin above operation and maintenance expense plus depreciation as referred to in § 53.54(b)(2)(B).

Response: See Exhibit G-4 and G-3.

(2) A detailed balance sheet of the utility as of the close of the period referred to in subsection (b)(2).
Response: See Exhibit G-1, Schedule 1.

(3) A summary, by detailed plant accounts, of the book value of the property of the utility at the date of the balance sheet required by paragraph (2).

Response: See Exhibit G-1, Schedule 2.

(4) A statement showing the amount of the depreciation reserve, at the date of the balance sheet required by paragraph (2), applicable to the property, summarized as required by paragraph (3).

Response: See Exhibit G-1, Schedule 2.

(5) A statement of operating income, setting forth the operating revenues and expenses by detailed accounts for the 12-month period ending on the date of the balance sheet required by paragraph (2).

Response: See Exhibit G-1, Schedule 3.

(6) A brief description of a major change in the operating or financial condition of the utility occurring between the date of the balance sheet required by paragraph (2) and the date of transmittal of the tariff, revision or supplement. As used in this paragraph, a major change is one which materially alters the operating or financial condition of the utility from that reflected in paragraphs (1)—(5).

Response: There were no significant changes.

(d) If a utility renders more than one type of public service, such as electric and gas, information required by § § 53.51—53.53 (relating to information furnished with the filing of rate changes), except subsection (c)(2), relates solely to the kind of service to which the tariff or tariff supplement is applicable. In subsection (c)(2), the book value of property used in furnishing each type of public service, as well as the depreciation reserve applicable to the property, shall be shown separately.

Response: Exhibit G-1, Schedules 2 and 4 show Pike's gas and electric information separately.

VERIFICATION

I, Charles Lenns, Vice President and Chief Financial Officer of Pike County Light & Power Company, hereby state that the facts set forth in the foregoing document 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 in this matter. This verification is made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

____

Charles Lenns
Senior Vice President and Chief Financial Officer
Pike County Light & Power Company

Dated: December 30, 2024

PCLP Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052357
	:	
Pike County Light & Power Company – Gas Division	:	

STATEMENT NO. 1-R

REBUTTAL TESTIMONY OF

PAUL M. NORMAND

ON BEHALF OF

PIKE COUNTY LIGHT & POWER COMPANY

Dated: May 1, 2025

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LIST OF EXHIBITS

Q. WOULD THE WITNESS PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Paul M. Normand, 1103 Rocky Drive, Suite 201, Reading, PA 19609.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Pike County Light & Power Company ("Pike" or "the Company").

Q. ARE YOU THE SAME PAUL M. NORMAND WHO PROVIDED PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to comment on the direct testimony of the OCA witness Karl Pavlovic and BI&E witness Ethan H Cline with respect to the Company's minimum distribution system results. I am also addressing comments made by OSBA witness Mark D. Ewen concerning revenue allocation and rate design. In addition, I am also addressing Mr. Pavlovic's testimony with respect to the proposed residential class customer charges and Mr. Cline's testimony regarding demand allocation factors. These comments will be presented in two parts (1) a brief discussion on the underlying concepts of a COS and (2) address specific direct testimony of OCA, I&E, and OSBA witness testimonies.

PART I – INTRODUCTION TO COST ANALYSIS AS RELATING TO OCA, I&E, AND OSBA TESTIMONY.

Q. DID YOU PREPARE A GAS EMBEDDED COST OF SERVICE STUDY ("COS") TO SUPPORT THE COMPANY'S RATE DESIGN PROPOSAL IN THIS PROCEEDING?

A. Yes. The development of the COS prepared for the Company was described in the Paul Normand's direct testimony on pages 6 through 14. Detailed COS results were provided with the Company's base rate filing as Exhibits G-6 through G-7 which fully support the detailed allocation factors of the study. The primary principle that guides the COS process is that of cost causation, the underlying drivers of costs. Each step in the development of the COS is consistent with the factors that drive or contribute to the incurrence of costs on the Pike system. The cost of service follows the general guidelines of the National Association of Regulatory Commissioners (NARUC) as well as standardized industry practices. As a result, the COS prepared for Pike provides an important reference point or guide as to the reasonableness of the Company's existing approved rates and should be considered along with other generally recognized factors such as customer impacts in the final design of new base rates in this proceeding as proposed by the Company.

Q. WOULD YOU BRIEFLY DEFINE THE PURPOSE OF AN EMBEDDED COST OF SERVICE STUDY?

A. The purpose of an embedded COS is to ensure that costs are allocated among customer classes in a fair and equitable manner. Costs can vary significantly between customer classes depending upon the nature of their demands (load) upon the system and the facilities required to serve them. These distribution costs are fixed in nature and have no relationship to volumetric consumption with respect to their design requirements, contrary to the other parties understanding. Any attempt to justify volumetric cost allocation is simply a means to an end with the results increasing existing subsidies which moves cost recovery away from the true cost of service as shown by the COS analysis. The purpose of an Embedded Cost of Service Study is to directly assign these fixed costs based on Company records or allocate each relevant cost on an appropriate basis in order to determine the proper cost to serve the respective classes under study.

The cost of service study result provides a benchmark to compare existing rates and revenue levels by class with respect to their underlying costs. It is a point estimate in time and not intended to exactly mirror the pricing in rate design proposals but simply to be used as a guide or direction for the proposed rate proposals.

Q. PLEASE SUMMARIZE YOUR COS RESULTS.

A. The results from our COS were presented in Statement No. 1, Direct Testimony of the Paul Normand, page 14 which has been repeated below in Table GR1 from Schedule PMN-2-G:

Table GR1

Cost of Service Results – Present ROR

	Schedule PMN-2-G	
	ROR (%)	ROR Index
Total Company	4.29%	1.00
Residential Space Heating	3.40%	0.79
Residential Domestic	0.63%	0.15
Residential Other	3.76%	0.88
General Service Commercial	19.84%	4.63
Commercial Space Heating	8.56%	2.00

This simply indicates the rate class comparison based on the existing pricing levels.

Q. WHY DID YOU PRESENT A COS WHICH INCLUDED A MINIMUM SYSTEM CUSTOMER COMPONENT IN YOUR ANALYSIS?

A. We introduced a customer component minimum system approach for two main reasons. The first reason is to provide continuity with the Company's last COS filing and the second reason is to recognize that the vast majority of mains connecting customers to the gas grid are 2" or less which is common for most gas utilities. Larger main pipe sizes aggregate these smaller mains and connect them to gas supply sources. Our effort was to simply highlight that these smaller sized pipes are closer to customers and influenced considerably by population density as opposed to the larger sized installed mains which are much more peak demand related as a result of aggregation.

Q. DID YOU UNBUNDLE THE COS TO REFLECT THE VARIOUS COST COMPONENTS TO HELP UNDERSTAND THE COST COMPONENTS THAT MAKE UP THE TOTAL REVENUE REQUIREMENTS FOR EACH CLASS?

A. Yes, we did. A detailed summary of all these cost categories has been provided in Exhibit G-6, Schedule PMN-5-G, pages 3 and 4 at the claimed rate of return requested of 8.59%. The revenues requirements associated with each cost category are fully shown on page 3, lines 12 through 18 for the customer related cost items.

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Q. CAN YOU MAKE A BRIEF COMPARISON OF THE FIXED CUSTOMER COSTS DEVELOPED FOR EACH MAJOR CLASS BASED ON YOUR RESULTS?

A. The following table presents the results as found in Exhibit G-6, Schedule PMN-5-G, page 4, lines 26 and 27 (2) and Exhibit G-8, pages 3 and 4 (1):

Table GR2

Cost of Service Results – Claimed ROR

	Existing Monthly Charge (1)	COS Meter & Service Costs (2)	Total Customer Costs (2)	Proposed Monthly Charge (1)
Total Residential	8.00	63.39	96.14	9.50
Residential Space Htg	8.00	63.41	96.16	9.50
Residential Domestic	8.00	63.00	95.61	9.50
Residential Other	8.00	62.95	95.56	9.50
General Service Comm	12.23	106.68	134.27	14.25
Commercial Space Htg	12.23	106.25	145.60	14.25

Q. COULD YOU COMMENT ON THESE MONTHLY CUSTOMER CHARGES?

A. Yes. As can be noted from the above Table GR2 customer cost results, the existing and proposed customer charges are but a very small fraction of the calculated costs (less than 16%) of only the service laterals and meter costs. Specifically, all of the proposed customer charges only recover a small portion of the costs of a service lateral connecting a customer to the gas main in the street and the related metering costs for each customer which are much lower than the total customer costs.

Q. WHY IS IT IMPORTANT TO COMPARE THE PROPOSED MONTHLY CUSTOMER CHARGE TO THE COST OF A SERVICE LATERAL AND A METER?

A. The important issue here is to recognize that each customer needs a service lateral and a meter in order to receive gas service from the company's local mains installed at the street. As we mentioned above, this is a basic need where the dedicated service cannot be utilized by anyone else. The COS monthly customer fixed cost is many times more than the level proposed. Our proposed levels are therefore entirely justified the remaining balance being collected through volumetric charges, which in most cases, are ultimately recovered by other users who cannot access the services and meter installations of other customers.

Q. DO YOU AGREE THAT THERE IS JUDGMENT INVOLVED IN THE PREPARATION OF AN ALLOCATED COST STUDY FOR A LOCAL DISTRIBUTION COMPANY ("LDC")?

A. Yes. It is necessary to apply expert judgment that reflects a number of factors including the nature of services the LDC provide, the demographics of its customers, the design of the LDC's facilities and guidance from the regulatory commission concerning acceptable allocation approaches. Appropriate cost allocation methods, such as we have utilized, take into account the factors noted above and yield a range of results that are within reasonable bounds to be used as a guide for rate design.

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Q. WHY DO YOU RECOMMEND THE USE OF DESIGN DAY FOR MAIN DEMAND ALLOCATION IN YOUR COS STUDY?

A. The use of annual class throughput is misleading and somewhat illogical as it completely ignores the planning process which is the major driver of distribution fixed costs based on design day delivery requirements for any gas utility. Specifically, the design day is the expected coldest day load high requirement of any gas utility where the maximum demand (load) level of gas delivery to customers would occur, which is typically the coldest month of the year. As a result, utilities must plan for this very large firm load requirement by installing facilities (compressors and mains) that will provide the capability for all firm customers. For Pike, this is a -9 degree day which is obviously a very cold day where load (demands) on the Company's infrastructure is at a maximum (reference provided file, "Pike Weather Norm Model 20 Yr 9-30-24 Rev11-20-24.xls). As a result, design day consideration is the most important and should be the only consideration in the underlying cost driver for distribution planning, a fact that was totally ignored and overlooked by the other parties' misleading comments relating to throughput (volumetric consumption) considerations. The current volumetric base revenue recovery is 91.5% of the total cost to service which is being recovered in the volumetric charges for SC1 (reference Exhibit G-8, page 3 and 11 of 13). When underlying gas costs, the total revenue recovery is over 95%, which signals essentially a volumetric rate with no specific demand recovery.

PART II – DISCUSSION OF OCA, I&E, AND OSBA TESTIMONY.

OCA - Karl Richard Pavlovic

Q. DO YOU AGREE WITH WITNESS PAVLOVIC'S CHARACTERIZATION OF THE MINIMUM SYSTEM FOR ACCOUNT 376 GAS MAINS?

A. No, I do not. As we stated earlier, the mains' costs use a wide variety of sizes to deliver gas supply to the customers. At one end of the gas distribution system are the much larger mains that aggregate load from the smaller mains (2" or less) to connect to the Company's gas supply sources. However, a very large amount of smaller installed mains (2" or less) is primarily used to connect individual customers to the gas grid. It is these smaller sized mains that are the closest to the individual customers that are much more related to customer count than their demand load as the Company installs most of the 2-inch mains for these local facilities. As a result, there are no mains allocation errors in the gas COS contradicting witness Pavlovic's claims (page 7 of his direct testimony).

Q. DO YOU AGREE WITH PAVLOVIC'S STATEMENT THAT THE MINIMUM-SIZE METHOD OF CLASSIFICATION FOR GAS MAINS DOES NOT REFLECT THE PLANNING, DESIGN, AND OPERATION OF PCLP'S DISTRIBUTION SYSTEM (PAGE 10)?

A. No, I do not. The major factor that drives mains investments is design day where volumes are not a consideration. This is the coldest level that can be anticipated as I previously discussed. This is followed by customer density and geography, but at no point are volumes a cost factor for distribution mains.

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Q. DO YOU AGREE WITH WITNESS PAVLOVIC'S RECOMMENDATION WITH RESPECT TO THE LEVEL OF THE RESIDENTIAL CUSTOMER CHARGES?

A. No, I do not. As we presented in the original filing (Exhibit G-6, Schedule PMN-5-G), the existing and proposed customer charges are a very small fraction (about 12% of services and meter cost of service) of the actual service lateral and metering costs to connect the customer to the gas grid. This is especially true when you consider residential cost recovery is over 95% on volumes which equates to essentially a volumetric rate for fixed cost recovery.

<u>I&E – Ethan H. Cline</u>

Q. DO YOU AGREE WITH WITNESS CLINE'S ALLOCATION OF MAIN COSTS BASED ON THE PEAK AND AVERAGE METHODOLOGY?

A. No. The design day allocation of mains is totally consistent with the engineering design and planning process that drive the capital investments made to deliver gas to customers on the coldest expected load level or design day. No other allocation method mentioned recognizes the major planning criteria for a gas utility. All of these other allocations do not reflect the planning process but simply achieve an end result for the analysts. Absent a minimum system customer component, the only rational approach to the allocation mains is the design day demands. This should be evident when reviewing the average weather normalized monthly throughput which is about 10.8X for the winter (January and February) versus the summer months for Residential and 3.97X for Commercial customers. (See attached Exhibit R-A.) This ratio alone suggests that volume is irrelevant with respect to any cost drivers.

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Q. DO YOU AGREE WITH WITNESS CLINE'S RECOMMENDATION TO ALLOCATE MAIN COSTS USING ONLY A DEMAND ALLOCATION FACTOR?

A. No, I do not as I have just discussed above.

Q. COULD YOU PLEASE COMMENT ON THE USE OF THE PEAK AND AVERAGE CONCEPT?

A. The Peak and Average (P/A) signals that this approach is key to the planning process. The P/A method is generally linked to the system characteristics (based on my experience) which are driven by peak load where the ratio is simply the average use over the design day peak. This ratio results in a load factor reflective of the system where the load factor reflects the average use with the residual being the demand-weighted component. In order to determine this ratio, I extrapolated pertinent data from Schedule PMN-4-G, page 15 of 28, as follows:

Annual Gas Throughput (Ccf)	1,509,018
Divided by 366 days	4,123
Design Day Demand	16,281
Load Factor	4,123 / 16,281
Equals	25.3%

As you can note, the correct percent if employed should be 25.3% and not a 50% level which is more reflective of electric utilities. A 50/50 relationship simply magnifies (incorrectly) the shift from demand to average use.

<u>OSBA – Mark D. Ewen</u>

Q. DO YOU AGREE WITH WITNESS EWEN'S COMMENTS CONCERNING COST OF SERVICE?

A. Mr. Ewen's testimony essentially accepts all aspects of the Company's Cost of Service testimony and results.

Q. DO YOU AGREE WITH MR. EWEN'S TESTIMONY ON CLASS REVENUE ALLOCATION AND RATE DESIGN?

A. No, I do not agree with Mr. Ewen's testimony with respect to class revenue allocation and rate design. My primary objective when designing rates was to maintain existing blocks coupled with a moderated class revenue requirement. This is driven by the large increase to the revenue requirement as shown on Exhibit G-8, page 1 of 13. Due to this increase, I also recommend no changes to the currently approved blocks. With respect to block rates, the initial block reflects the recovery of a portion of demand costs and volumes up to 300 Ccf. Reducing or flattening of these blocks would be counterproductive to sound rate design objectives since the majority of costs in the first block reflect demand-related costs.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

EXHIBIT R - A

Pike County Light & Power - Gas
Average Use per Customer
Weather Normalized Calendar Month Sales, CCF

		July 2024	August 2024	Total Jul & Aug	January 2024	February 2024	Total Jan & Feb
	CALENDAR MONTH SALES, CCF						
1	Residential Space Htg - 231	17,480	17,228	34,708	205,105	170,378	375,484
2	Residential Domestic - 631	603	581	1,184	5,561	4,669	10,230
3	Resid Other - 531 & 731	71	65	136	845	705	1,550
4	Total Residential CCF Sales	18,154	17,873	36,027	211,511	175,753	387,264
5							
6	Total Residential Customers	1,282	1,285	2,567	1,276	1,276	2,552
7							
8	**Residential CCF Use per Customer**			**14.03**	**Winter to summer**	**10.81**	**151.75**
9							
10							
11	General Serv Comm - 162	9,201	9,457	18,658	25,946	21,904	47,850
12	Comm Space Htg - 331	5,701	5,639	11,340	38,618	33,209	71,826
13	Total Commercial CCF Sales	14,902	15,096	29,998	64,564	55,113	119,677
14							
15	Total Commercial Customers	83	83	166	84	83	167
16							
17	**Commercial CCF Use per Customer**			**180.71**	**Winter to summer**	**3.97**	**716.63**
18							
19							
20	Source: Provided spreadsheet "Pike Weather Norm Model 20 Yr 9-30-24 Rev 11-20-24.xls".						

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052357
	:	
Pike County Light & Power Company – Gas Division	:	
	:	

Statement No. 2-R

Rebuttal Testimony of

Accounting Panel

Charles Lenns and Matthew Lenns

Date: May 1, 2025

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Q. HAVE THE MEMBERS OF THE ACCOUNTING PANEL PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes, we submitted direct testimony (Statement No. 2) that discussed the major costs driving the rate increase Pike is seeking and discussed the adjustments made to the Historic Test Year in order to calculate the requested rate increase. In addition, our testimony outlined a request to put a Weather Normalization Adjustment Mechanism ("WNA") into effect for gas customers.

PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF THE ACCOUNTING PANEL'S REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The Accounting Panel's Rebuttal Testimony will cover the following topics:

- Explain updates to the Company's Rate Base and Revenue Requirement calculations to correct inadvertent computational errors that came to light as part of the discovery process and discussed in other parties' direct testimony.
- Adopt as part of the Company's Rebuttal position, in whole or in part, certain adjustments proposed by the Bureau of Investigation and Enforcement's ("I&E") witness Zachari Walker (I&E Statement 1) and by Office of Consumer Advocate's ("OCA") witness Jennifer L. Rogers (OCA Statement 1).
- Address and rebut adjustments proposed by I&E witnesses Zachari Walker (I&E Statement 1) and Ethan H. Cline (I&E Statement 3) as well as OCA witness Jennifer L. Rogers (OCA Statement 1) that the Company does not believe are appropriate.

- Discuss the Capital Structure and interest rate recommendations of I&E witness Christopher Keller (I&E Statement 2) and OCA witness Maureen L. Reno (OCA Statement 2).
- Address concerns raised by I&E witness Ethan H. Cline (I&E Statement 2) and OCA witness Karl Richard Pavlovic (OCA Statement 3) concerning the Company's proposal to implement a WNA.

Q. HAS THE COMPANY'S CLAIM IN THIS PROCEEDING CHANGED FROM ITS INITIAL FILING?

A. No. The Company continues to request a revenue increase of $905,900 and implementation of a Weather Normalization Adjustment.

UPDATES – RATE BASE

Plant, Accumulated Depreciation, and Accumulated Deferred Income Taxes:

Q., PLEASE DISCUSS THE RATE BASE ADJUSTMENTS PROPOSED BY I&E WITNESS ETHAN H. CLINE (I&E STATEMENT 3) AND OCA WITNESS JENNIFER L. ROGERS (OCA STATEMENT 1) TO PLANT AND THE ACCUMULATED RESERVE FOR DEPRECIATION THAT THE COMPANY IS CONTESTING.

A. I&E witness Ethan H. Cline (I&E Statement 3, pages 16 - 23) and OCA witness Jennifer L. Rogers (OCA Statement 1, pages 6-7) recommended eliminating all requested gas and common plant additions occurring after the Future Test Year (i.e., October 1, 2025 – March 31, 2026) along with the associated Accumulated Depreciation Reserve.

Q. HOW MANY ADJUSTMENTS WERE MADE TO PLANT FOR THE TEST YEAR PLANT ADDITIONS?

A. I&E witness Ethan H. Cline decreased gas utility plant by $1,189,200 (I&E Statement 3, page 23, line 1). He also made an adjustment to reduce common utility plant allocated to gas by $12,700 (I&E Statement 3, page 23, line 2).

OCA witness Jennifer L. Rogers reflected an adjustment to reduce both Post Future Test Year gas plant and common plant allocated to gas by $1,201,900 (OCA Statement 1, page 7, lines 6 -10). Her one adjustment is equivalent to Witness Cline's two separate adjustments ($1,189,200 + $12,700).

Q. HOW MUCH OF AN ADJUSTMENT WAS MADE TO THE ACCUMULATED DEPRECIATION RESERVE THAT WAS RELATED TO THE TEST YEAR PLANT ADDITIONS?

A. I&E witness Ethan H. Cline decreased the gas accumulated depreciation reserve by a net of $133,600 (I&E Statement 3, page 23, line 3). He also made an adjustment to reduce the common accumulated depreciation reserve allocated to gas by a net of $18,100 (I&E Statement 3, page 23, line 3). His proposed adjustments to the depreciation reserve did not reflect the impact of retirements during the October 1, 2025 – March 31, 2026 time period on the depreciation reserve, which was inconsistent with his reduction to plant in service adjustment.

OCA witness Jennifer L. Rogers reflected an adjustment to reduce both Post Future Test Year gas and common accumulated depreciation reserves allocated to gas of $88,430 (OCA Statement 1, page 7, lines 22-23). Her one adjustment to the depreciation reserve was calculated correctly. The amount of the adjustment to gas accumulated depreciation that should have been reflected by Ethan H. Cline was $86,600 for gas plant and $1,830 for common plant allocated to gas for a total reduction of accumulated depreciation of $88,430, not the $133,600 reduction that witness Cline calculated.

Q. PLEASE DISCUSS THE RATE BASE ADJUSTMENTS PROPOSED BY I&E WITNESS ZACHARI WALKER (I&E STATEMENT 1) AND OCA WITNESS JENNIFER L. ROGERS (OCA STATEMENT 1) TO ACCUMULATED DEFERRED INCOME TAXES.

A. I&E witness Zachari Walker (I&E Statement 1, page 26, lines 13-14) and OCA witness Jennifer L. Rogers (OCA Statement 1, pages 8, lines 4-11) recommended increasing Accumulated Deferred Income Taxes by $10,800. Their proposed adjustment tracks the decrease in Post Future Test Year Plant Additions discussed previously.

To the extent the Commission does not adopt the proposed adjustments for Post Test Year plant additions, the adjustment to Accumulated Deferred Income Taxes should also be reversed.

Q. HAS THE ACCOUNTING PANEL MADE THE ADJUSTMENTS DISCUSSED ABOVE TO ELIMINATE THE POST FUTURE TEST PLANT ADDITIONS, THE ASSOCIATED ACCUMULATED DEPRECIATION RESERVE, AND ACCUMULATED DEFERRED INCOME TAXES AS PART OF THIS UPDATE?

A. Yes. As shown in the Revenue Requirement Update table below, Rate Base was reduced by $1,124,270 ($1,201,900 - $88,430 + $10,800), which lowered the revenue requirement by $118,600 ($126,800 - 9,200 + 1,000).

Cash Working Capital – Lead Lag Study

Q. DO THE COMPANY'S CASH WORKING CAPITAL CALCULATIONS REFLECT ANY UPDATES?

A. Yes. The Company's Lead Lag Study was updated to reflect the impact of eliminating two O&M adjustments—the $30,000 out of period intercompany charge and the escalation adjustment of $7,800 that we will discuss later in our testimony. In making these two adjustments it was necessary to also restate the Future Test Year Lead Lag Study which had 100% of the intercompany charges instead of 15% in the calculation. The offset is in the other O&M category. As a result of these adjustments, while the total O&M decreased by $37,800, the cash working capital requirement increased by $16,000 and produced a $1,300 higher revenue requirement. The difference in lag periods between intercompany charges of 30 days vs. other O&M charges of 23 days is responsible for the increase in working capital requirements.

Deferred Debits – Rate Case Costs

Q. DID I&E WITNESS ZACHARI WALKER AND OCA WITNESS JENNIFER L. ROGERS PROPOSE AN ADJUSTMENT TO DEFERRED DEBITS RELATED TO RATE CASE COSTS?

A. Yes. Both I&E witness Zachari Walker and OCA witness Jennifer L. Rogers made an adjustment to remove Rate Case costs of $37,500 from Rate Base in order to facilitate normalizing vs. amortizing this expense. While the Company does not agree with the Commission's policy of normalizing vs. amortizing this element of expense for reasons we will cover later in testimony, the Accounting Panel has removed this item from Rate Base as part of its Update. As shown in the Revenue Requirement Update table below, Rate Base was reduced by $34,700, which lowered the revenue requirement by $2,800.

Deferred TCJA Credits

Q. I&E WITNESS ZACHARI WALKER PROPOSED A NUMBER OF ADJUSTMENTS TO THE DEFERRED CREDIT BALANCE THAT WAS ESTABLISHED FOR TCJA TAX BENEFITS. DO YOU AGREE WITH HIS PROPOSED RATE BASE ADJUSTMENTS?

A. Yes. The Company's filing inadvertently reflected the Accumulated TCJA Deferred Tax Benefits "net of tax." I&E witness Zachari Walker's adjustment properly reflects the gross amount of the Accumulated TCJA Deferred Taxes in Rate Base. As shown in the table below, Rate Base was reduced by $1,600, which lowered the revenue requirement by $100. In addition, the amortization of the Accumulated TCJA Deferred Tax balance has now been reflected in the Company's Income Tax calculation as part of this Update.

Future Test Year – Operating Revenues (DSIC Surcharge)

Q. PLEASE DISCUSS YOUR UPDATE FOR OPERATING REVENUES SHOWN IN THE ACCOUNTING PANEL'S STATEMENT NO. 2 EXHIBIT G-4, SCHEDULE 1, PAGE 1 OF 2?

A. Exhibit G-4, Schedule 1, Page 1 of 2 shows the Historic and Future Test Year Operating Revenues. The Exhibit inadvertently included a forecast of the DSIC Revenue Surcharge in the Future Test Year, which had the impact of understating the Company's Gas Revenue Requirement. The Gas DSIC Surcharge will be $0 when base rates are reset.

Q. HAS THE ACCOUNTING PANEL MADE AN ADJUSTMENT TO ELIMINATE THE FUTURE TEST YEAR DSIC SURCHARGE AS PART OF THIS UPDATE?

A. Yes. As shown in the Revenue Requirement Update table below, operating revenues were reduced by $97,800, which lowered the revenue requirement by $98,000.

<u>Intercompany M&T charges</u>

Q., PLEASE DISCUSS YOUR UPDATE FOR INTERCOMPANY CHARGES SHOWN IN THE ACCOUNTING PANEL'S STATEMENT NO. 2 EXHIBIT G-4, SCHEDULE 6?

A. Exhibit G-4, Schedule 6 shows the historic intercompany charges for the twelve months ended September 30, 2024 for both electric and gas operations of $780,177 to which the Company applied a 1.0% general inflation rate to calculate an adjustment of $7,800. In providing the details supporting the intercompany charges in discovery it was discovered that a $200,000 nonrecurring charge was included in the Historic Test Year level of expense. Intercompany charges were allocated 85% to electric operations and 15% to gas operations in the Historic Test Year.

The Company has reflected two adjustments in the Update for intercompany expense. The first is to reduce intercompany expense by $30,000 ($200,000 x 15%) in order to eliminate the gas portion of this out of period charge. The second adjustment removes the escalation amount of $7,800 which was not allocated and added in total to the Historic Intercompany expense. When combined, the adjustments result in a reduction of $37,800 ($30,000 + $7,800). As shown in the Revenue Requirement Update table below, the adjustments for intercompany charges lowered the gas revenue requirement by $37,900 ($30,100 + $7,800).

Q. DID I&E WITNESS ZACHARI WALKER AND OCA WITNESS JENNIFER L. ROGERS PROPOSE A SIMILAR ADJUSTMENT?

A Yes. Both I&E witness Zachari Walker (I&E Statement 1, page 14, lines 11-13) and OCA witness Jennifer L. Rogers made adjustments to eliminate the gas portion of the out of period charge and the Company's escalation adjustment.

<u>DEPRECIATION EXPENSE ON POST FUTURE TEST YEAR PLANT</u>

Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT PROPOSED BY I&E WITNESS ETHAN H. CLINE (I&E STATEMENT 3) AND OCA WITNESS JENNIFER L. ROGERS (OCA STATEMENT 1) THAT THE COMPANY IS CONTESTING.

A. Consistent with their recommended adjustment to reduce the depreciation reserve for Post Future Test Year Plant, I&E witness Ethan H. Cline (I&E Statement 3, page 24, lines 6-7) reduced depreciation expense by $34,100 and OCA witness Jennifer L. Rogers (OCA Statement 1, pages 10, lines 12-18) recommended eliminating the associated book depreciation expense in the amount of $33,279. The differences in the two calculated depreciation expense adjustments amounts to $821 ($34,100 - $33,279). The variation was caused by the weighting of the composite depreciation rate in OCA's calculation for the future test year plant. The Company believes Jennifer L. Rogers' adjustment is accurate.

Q. HAS THE ACCOUNTING PANEL MADE THE ADJUSTMENTS DISCUSSED ABOVE TO ELIMINATE DEPRECIATION EXPENSE ON POST FUTURE TEST PLANT ADDITIONS PART OF THIS UPDATE?

A. Yes. As shown in the Revenue Requirement Update table below, depreciation expense was reduced by $33,279, which lowered the revenue requirement by $33,400.

<u>Federal and State Income Tax - Interest Deduction</u>

Q. DOES THE ACCOUNTING PANEL HAVE A CORRECTION TO THE CALCULATED INTEREST DEDUCTION REFLECTED IN FEDERAL AND STATE INCOME TAX CALCULATIONS SHOWN IN EXHIBIT E-6, SCHEDULE 14, PAGES 1 AND 3?

A. Yes. In calculating the annual interest deduction shown on Exhibit G-4, Schedule 10, Page 3, the Accounting Panel inadvertently multiplied the Company's "unweighted cost of debt" interest rate, rather than the "embedded cost of debt" rate. This resulted in an interest deduction in the federal and state income tax calculation that was more than twice as large as it should have been, artificially lowering the Company's income tax expense and understating the gas revenue requirement.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE "UNWEIGHTED COST OF DEBT" INTEREST RATE AND THE "EMBEDDED COST OF DEBT" INTEREST RATE?

A. The "unweighted cost of debt" interest rate represents the average interest rate paid by the Company on all short and long-term debt. The "embedded cost of debt" interest rate represents the cost as a percentage of the overall cost of capital, which would include equity financing. To the extent that short and long-term debt represent roughly 50% of the Company's total Capital Structure, the "embedded cost of debt" is roughly 50% of the "unweighted cost of debt."

Q. WHAT IS THE COMPANY'S "UNWEIGHTED COST OF DEBT" INTEREST RATE AS COMPARED TO ITS "EMBEDDED COST OF DEBT" INTEREST RATE AND WHAT IS THE IMPACT OF USING THE "EMBEDDED COST OF INTEREST RATE" ON THE INCOME TAX CALCULATION?

A. The Company's "unweighted cost of debt" interest rate is 7.21% as compared to its "embedded cost of debt" interest rate of 3.43%. Applying the "embedded cost of debt" interest rate to Exhibit G-4, Schedule 14, page 3 lowers the gas Future Test Year interest deduction from $770,000 to $403,700 and the associated federal and state income taxes from 210,300 to $110,300. The gas revenue requirement impact of this change is approximately $151,900.

Q. DID I&E WITNESS ZACHARI WALKER AND OCA WITNESS JENNIFER L. ROGERS RECOMMEND A SIMILAR CORRECTION?

A Yes. On page 29 of I&E Statement 1, Zachari Walker discussed the correction required in the income tax calculations to reflect the embedded cost of debt into the Company's income tax calculation rather than the "unweighted cost of debt" interest rate. The adjustment proposed by Zachari Walker also reflected the impact of all of I&E's rate base adjustments associated with plant, deferred debits, and deferred credits and, as a result, his adjustment is net of those other items. OCA witness Jennifer L. Rogers discussed the same adjustment in OCA Statement 1, page 23, lines 12-19.

Deferred FIT Expense (TCJA Tax Benefits)

Q. PREVIOUSLY YOU DISCUSSED AN ADJUSTMENT TO RATE BASE FOR THE TCJA DEFERRED TAX BENEFITS THAT WERE INADVERTENTLY SHOWN "NET OF TAX" IN RATE BASE. IS THERE AN ASSOCIATED INCOME TAX ADJUSTMENT THAT ALSO IS REQUIRED?

A. Yes. The Company's income tax calculations included in Pike Gas Statement 2, Exhibit G-4, Schedule 10, page 1 should have included an amortization of the Accumulated Deferred Income Taxes associated with the TCJA tax benefits. This amortization is missing from the income tax schedules and should have been broken out in a separate line.

Q. WHAT IS THE IMPACT OF REFLECTING THE AMORTIZATION OF THE TCJA ACCUMULATED DEFERRED INCOME TAXES?

A. The amortization of TCJA Accumulated tax benefits increases total gas income tax expense by $8,303, which increases the revenue requirement by approximately $11,400 ($8,303 x the gross up factor of 1.3796).

Q. DID I&E WITNESS ZACHARI WALKER RECOMMEND A SIMILAR CORRECTION?

A. Yes. Zachari Walker proposed the same adjustment (I&E Statement 1, page 25, lines 10-18).

Revenue Requirement

Q. WHAT IS THE IMPACT OF ALL OF THE UPDATES AND CORRECTIONS TO THE COMPANY'S CALCULATED REVENUE REQUIREMENT DISCUSSED PREVIOUSLY?

A. As shown in the Revenue Requirement Update table below, the updates and corrections to the revenue requirement would have the effect of increasing the gas revenue requirement by $69,800 from $905,900 to $975,700. We would note that the Company is not seeking a rate increase greater than $905,900, but to the extent that any of the other adjustments proposed by I&E witnesses Zachari Walker and Ethan H. Cline, as well as OCA witnesses Jennifer L. Rogers and Maureen L. Reno are adopted, the impact of these updates and corrections should also be reflected to arrive at the final gas revenue requirement.

			Pike AP-G Update Summary
Pike County Light & Power Company, Inc.			
Gas Rate Cast R-2024-3052357			
Revenue Requirement Updates			
	April Update Adjustment	**Rev. Reqm't Impact**	
Rate Increase (As Filed)			**$ 905,900**
Operating Revenues			
Eliminate FTY DSIC Revenues	$ 97,800	$ 98,000	
Operating Expenses			
Intercompany M&T Charges	(30,000)	(30,100)	
Escalation of Interco Charges	(7,800)	(7,800)	
Book Depreciation Expense			
Post Future Test Year Depreciation	(33,279)	(33,400)	
Income Tax Expense			
Amort of Def TCJA Income Tax Credits:			
Reflect current amort. in FIT calculation	8,591	11,800	
Reflect additional amort. in FIT calculation	(288)	(400)	
Interest Synchronization			
Corrected Embedded Cost of Debt	403,668	151,900	
Rate Base			
Post Future Test Year	(1,201,900)	(126,800)	
Plant Additions	88,430	9,200	
Depreciation Reserve	(10,800)	(1,000)	
Accumulated Deferred Income Taxes			
Cash Working Capital			
Intercompany M&T Charges - Restate O&M	16,000	1,300	
Deferred Debits			
Eliminated Deferred Rate Case Expense	(34,700)	(2,800)	
Other Deferred Credits			
Correct Accumulated Deferred TCJA Credits	(1,600)	(100)	
Total Update Adjustments			69,800
Revenue Requirement with Update Adjustments			**$ 975,700**

REBUTTAL OF ADJUSTMENTS PROPOSED BY PARTIES

Rate Base

Rate Base Adjustments – Cash Working Capital

Q. DOES THE ACCOUNTING PANEL AGREE THAT THE ADJUSTMENT TO THE WORKING CAPITAL ALLOWANCE PROPOSED BY OCA WITNESS JENNIFER L. ROGERS IN HER DIRECT TESTIMONY IS CONSISTENT WITH HER OTHER ADJUSTMENTS TO OPERATING EXPENSES (PAGE 10)?

A. The Accounting Panel agrees that OCA witness Jennifer L. Rogers appropriately reflected her proposed O&M adjustments in the Company's Lead Lag workpapers in order to recalculate the Working Capital Allowance. To the extent that her recommended adjustments are eliminated or modified, the calculation will need to be updated to reflect all final changes adopted by the Commission.

Cost of Service

Normalization / Amortization Periods

Q. WHAT AMORTIZATION PERIODS DID THE COMPANY AND I&E WITNESS ZACHARI WALKER (I&E STATEMENT 1) RECOMMEND IN THIS CASE FOR NORMALIZING RATE CASE EXPENSES AND AMORTIZING DEFERRED STORM COSTS?

A. The Company recommended a four-year time period for recovering rate case costs, which we believe will be the normal cycle for base rate filings going forward, assuming the Company obtains just and reasonable rate relief in this proceeding and the continuation of its LTIIP infrastructure plan and the associated DSIC surcharges.

I&E witness Zachari Walker proposed a five-year period (sixty months) for rate case normalization and storm costs amortization.

Q. DOES THE COMPANY'S ACCOUNTING PANEL AGREE THAT USING A 66-MONTH (FIVE AND A HALF YEAR) NORMALIZATION PERIOD FOR RATE CASE COSTS IS APPROPRIATE?

A. No. We do not agree that setting longer periods to normalize rate case costs is appropriate. The argument set forth by I&E witness Zachari Walker that historically the average period between the Company's last three base rate case filings was 66 months (I&E Statement 1 page 8, lines 15-16) is not an indication of how frequently the Company will file for rate increases going forward. The time period between when the Company filed its last base rate case (R-2020-3022130) on October 24, 2020 and the current case was slightly less than 51 months or 4.25 years.

Q. WHY ISN'T THE HISTORIC FREQUENCY OF RATE CASE FILINGS A GOOD INDICATION OF WHEN PCLP WILL NEED TO FILE FOR ITS NEXT RATE CHANGE?

A. PCLP is now operating under different ownership than reflected in the historical data. The Company was previously acquired by Con Edison Inc. ("CEI") in 1998 as part of its merger with Orange and Rockland Utilities, Inc. PCLP was the only utility operation that CEI had in Pennsylvania and represented approximately one tenth of one percent (i.e., 0.001 or 0.1%) of all of its utility customers and revenues. As a result, PCLP's financial results did not have a material impact on CEI's earnings or credit worthiness. CEI filed rate cases for PCLP when it owned the Company in order to avoid defaults on loan covenants that would have triggered requirements for PCLP to repay outstanding debt when their earnings did not support the debt service cost. By comparison, PCLP represents approximately 25% of Corning Natural Gas Holding Company's ("CNGH") total revenues and 25% of CNGH total utility plant investment. Its financial operating results have a much more significant impact on CNGH's financial operating results and is therefore more likely to drive the need for more frequent rate changes in order to maintain a reasonable return on infrastructure investments.

There were three reasons why the Company had waited to file its last case. First, the settlement in the 2014 Rate Case had a stay-out provision of two years that precluded PCLP from filing for new rates until 2016. Second, the settlement of CNGH's acquisition case in 2016 also had a stay-out provision that did not allow for a change in base rates for two years. Third, as a practical matter, it took CNGH time to staff and integrate Pike's daily operations with that of its New York utility affiliate Corning Natural Gas Company, Inc. ("CNG").

Based on the foregoing, a normalization period of more than four years is in the view of the Accounting Panel unreasonable.

Q. DOES THE COMPANY AGREE WITH I&E WITNESS ZACHARI WALKER'S ARGUMENTS THAT HISTORICAL FREQUENCY OF RATE CASE FILINGS IS A BETTER INDICATOR OF FUTURE FILINGS?

A. No. PCLP anticipates that it will be filing more frequently than it has in the past. Spreading out the recovery of rate case costs will require the Company to file its next rate case sooner rather than later.

Deferral vs. Normalization of Rate Case Costs

Q., PLEASE DISCUSS THE COMPANY'S REASONS FOR OPPOSING I&E WITNESS ZACHARI WALKER RECOMMENDATION TO "NORMALIZE" THE LEVEL OF RATE CASE COSTS TO BE INCLUDED IN RATES AS OPPOSED TO DEFERRING AND AMORTIZING THOSE COSTS.

A. The Company opposes normalizing rate case costs rather than deferring and then amortizing them because it would require PCLP to write off all rate case costs in the current period, which has a material and significant impact on the Company's earnings. In the historic Test Year, Pike had net income from both gas and electric operations of $1,292,367 (Exhibit E-1, Schedule 3). A charge to expense of $250,000 (Electric of $212,500 + Gas of $37,500) in that period of time would have resulted in an after-tax charge to earnings of approximately $180,700 {$250,000 x (1 - 27.7071%)}, which would have been equivalent to approximately 14% of the Company's net income. This reduction to net income would likely result in an increase in future interest rates on Company debt which will result in additional reductions to Company net income. While net income should be higher after October 2025 as a result of rate relief, normalizing this cost will require the Company to charge income in the current period. For larger utilities, writing off rate case costs in the current period has a much smaller and less material impact on their financial operating results. Deferring and amortizing this cost will match the amounts charged to expense with the revenues collected from customers and avoid a material impact on the Company's financial operating results.

<u>Informational Advertising</u>

Q. OCA WITNESS JENNIFER L. ROGERS PROPOSED AN ADJUSTMENT TO "NORMALIZE" HISTORIC INFORMATIONAL ADVERTISING EXPENSES BY UTILIZING A THREE-YEAR AVERAGE OF THOSE COSTS. DOES THE ACCOUNTING PANEL AGREE WITH THIS ADJUSTMENT?

A. No. We do not. The historic time periods do not represent a normal level of informational advertising due to the COVID Pandemic. During the Pandemic many businesses were closed limiting the number of media products and services that were available to the Company. PCLP's operations were primarily focused on continuing to provide essential safe and reliable services to all customers during this time period. While informational advertising and customer education on the safe and efficient use of energy is an important element of the Company's operations, given all the issues surrounding the Pandemic, customer safety advertising was not given the same level of attention during the Pandemic as the Company is currently able to provide. As a result, the Accounting Panel recommends that OCA witness Jennifer L. Rogers' adjustment to reduce the level of funding for informational advertising be rejected. These advertisements contain necessary information to educate customers on safe and efficient use of energy and the Company is required to provide customers this information. It is neither just nor reasonable to exclude any amounts of informational advertising.

<u>Auditing</u>

Q. OCA WITNESS JENNIFER L. ROGERS PROPOSED AN ADJUSTMENT TO "NORMALIZE" HISTORIC OUTSIDE AUDITING EXPENSES BY UTILIZING A THREE-YEAR AVERAGE OF THOSE COSTS. DOES THE ACCOUNTING PANEL AGREE WITH THIS PROPOSED ADJUSTMENT?

A. No. While the Company does agree that it was transitioning to a new outside auditing firm (PWC) during the Historic Test Year, it does agree that these costs are necessarily higher than they would have been absent the change or going forward. Based on the experience of the Accounting Panel, who both worked for "Big Four" public accounting firms, more often than not, these firms absorb most of the transitional costs of switching from one external auditor to another in order to obtain new long-term clients. Publicly-owned corporations rarely change their outside auditors because doing so may create a number of questions and concerns from the Securities and Exchange Commission and investors as to why the change was made. In the case of Pike, the change was made because its parent company utilizes PWC as their outside independent auditors and believed greater transparency, consistency, and oversight would be achieved if all of its investee companies were audited by the same accounting firm. In addition, the Company believes that having one of the "Big Four" firms as its auditor was beneficial to the Company when it refinanced its debt in the private lender market.

The scope, testing, and work performed each year by independent outside public accountants will change and the Accounting Panel believes the Historic Test Year level of audit fees are within reason and will continue. As a result, the Accounting Panel recommends that OCA witness Jennifer L. Rogers' adjustment to reduce the level of funding for outside independent audit fees be rejected.

Annual Dinner Expense

Q. OCA WITNESS JENNIFER L. ROGERS PROPOSED AN ADJUSTMENT TO ELIMINATE THE GAS PORTION $240 ($1,600 X 15%) OF AMOUNTS SPENT FOR THE PIKE COMMUNITY FOUNDATION ANNUAL DINNER. DOES THE ACCOUNTING PANEL AGREE WITH THIS ADJUSTMENT?

A. No. The expenditure for the Pike Community Foundation Annual Dinner provides one means for Company representatives to meet with community business and political leaders and discuss any potential concerns or issues they may have with the Company. It is a forum for open discussion and an important outreach opportunity to increase awareness of the services the Company offers its customers (e.g., low-income programs) and it provides the community with an opportunity to express any concerns or recommendations regarding the Company's response time to gas leaks. In addition, attending these functions offers the Company access to business and political leaders that allows the Company to better understand growth opportunities that will in turn better enable the Company to plan for capital needs to provide utility service for growth projects. OCA witness Jennifer L. Rogers' recommendation to disallow this expenditure is based on her belief that the purpose of the dinner was to improve the Company's image with the community and would only benefit shareholders. PCLP believes just the opposite—the dinner is part of its outreach efforts with the local community and is done primarily to benefit customers. As a result, the Accounting Panel recommends that the Commission reject OCA witness Jennifer L.

Rogers' adjustment that would eliminate the gas portion of the Pike Community Foundation Annual Dinner expense.

Capital Structure

Q. DOES THE COMPANY'S WITNESS CHRISTOPHER M. WALL DISCUSS THE APPROPRIATENESS OF THE COMPANY'S CAPITAL STRUCTURE REFLECTED IN THIS ELECTRIC RATE CASE?

A. Yes. On pages XX – YY of Company Statement 4R, Mr. Wall explains why the Company's Capital Structure is appropriate. The Company's Accounting Panel adds the following observations to further support his testimony.

Q. THE COMPANY'S CAPITAL STRUCTURE FOR THE FUTURE TEST YEAR CONSISTS OF 40.73% LONG-TERM DEBT, 8.64% SHORT-TERM DEBT, AND 50.63% COMMON EQUITY. WHAT CAPITAL STRUCTURE DID I&E WITNESS CHRISTOPHER KELLER AND OCA WITNESS MAUREEN L. RENO RECOMMEND FOR THE COMPANY IN THIS CASE?

A. I&E witness Christopher Keller (I&E Statement 2, page 11, lines 3–4) recommended using the Company's Capital Structure as did OCA witness Maureen L. Reno (OCA Statement 2, page 23, lines 14-17), indicating "Pike's proposed equity ratio of 50.63%, based on the FTY, is reasonable for determining its capital structure in the current proceeding."

Q. DID OCA WITNESS MAUREEN L. RENO QUALIFY HER ANSWER TO THE PRIOR QUESTION AND INDICATE THAT THERE SHOULD BE SOME LIMITATIONS PLACED ON THE COMPANY'S 50.63% EQUITY RATIO?

A. Yes. OCA witness Maureen L. Reno (OCA Statement 2, page 23, lines 20 – 22) indicated that the Company equity ratio of 50.22% should be established as a maximum. While she stated that the proposed equity ratio of 50.63% falls within the range of annual average equity ratios approved by regulatory commissions for regulated gas utilities since 2020, she indicated that Pike's proposed equity ratio of 50.63% exceeds the proxy group she used in her comparisons. She did not, however, propose any adjustment to lower Pike's equity ratio.

Q. DOES THE ACCOUNTING PANEL AGREE WITH OCA WITNESS MAUREEN L. RENO'S RECOMMENDATION TO "CAP" THE COMPANY'S 50.22% EQUITY RATIO?

A. No. The Accounting Panel does not agree that its equity ratio should capped at 50.22%. Ms. Reno is proposing a hypothetical capital structure. The Commission has ruled time and again that the standard for use of a hypothetical capital structure requires that the actual capital structure "is atypical or too heavily weighted on either the debt or equity side." *Pa. PUC et. al. v. Columbia Water Company*, R-2023-3040258, Opinion and Order at 83-84, (Order entered Jan. 18, 2024) *rehearing denied.* As Ms. Reno admits, Pike's actual structure in fact falls within the range of annual average equity ratios approved by regulatory commissions for regulated gas utilities. There is absolutely no evidence or basis to impose a hypothetical capital structure on Pike.

Interest Rates

Q. THE COMPANY'S FILING REFLECTED A SHORT-TERM INTEREST RATE OF 7.58%. WHAT POSITIONS DID I&E AND OCA WITNESSES TAKE REGARDING THE COMPANY'S SHORT-TERM INTEREST RATE?

A. Christopher Keller (I&E Statement 2, page 13, lines 13-15) recommended adoption of the Company's short-term interest rate, while OCA witness Maureen L. Reno (OCA Statement 2, page 28, lines 6-11) recommended that the short-term interest rate be capped at the current Prime Interest Rate of 7.50%. Her justification for using the Prime Interest Rate was that a "regulated utility has a less risky credit profile than a typical homebuyer."

Q. WHAT IS THE ACCOUNTING PANEL'S UNDERSTANDING OF THE PRIME INTEREST RATE AND HOW IT IS APPLIED TO CORPORATIONS?

A. It is the understanding of the Accounting Panel that the Prime Interest Rate is paid by corporations based on their individual credit ratings. Companies with better credit ratings pay an amount equal to, or less than, the Prime Interest Rate and those with lower credit ratings often must pay more. We don't understand Maureen L. Reno's assertion that because regulated utilities are less risky than typical homebuyers, they should not pay more than the Prime Interest Rate. In fact, prior to the Company's refinancing transaction, Pike's sole lender offered a short-term interest rate equal to SOFR plus 4%. At the time of refinancing, this interest rate exceeded 9%. The Company's short-term interest rate upon refinancing was more than 1% lower than the rate offered to it by its long-time sole lender. Accordingly, Ms. Reno's proposed adjustment to cap short-term interest rates at no more than the Prime interest rate should be rejected. Moreover, 7.58% is the actual rate the

Company is incurring. It is neither just nor reasonable to deny the Company actual, proven, and prudently incurred expenses.

Q. REGARDING THE LONG-TERM INTEREST RATE OF 6.8% REFLECTED IN THIS FILING, WHAT POSITIONS DID I&E AND OCA WITNESSES TAKE REGARDING THE COMPANY'S SHORT-TERM INTEREST RATE??

A. Yes. Christopher Keller (I&E Statement 2, page 12, line 8) recommended adoption of the Company's long-term interest rate because it reflected the Company's newly refinanced long-term debt issued on September 12, 2024 in the amount of $17.584 9 million at a coupon rate of 6.31%, plus the unamortized debt issuance expenses to arrive at 6.8%**.**

Maureen L. Reno (OCA Statement 2, page 27, lines 17-20) made an unsubstantiated claim that "Pike's management had multiple opportunities to refinance its long-term debt in prior years when interest rates for BB- credits were significantly lower than 6.80%." She proposed instead a 6.00% cost of long-term debt for Pike in this proceeding, as this reflects the current (2025) average interest rate for Moody's Baa12 (OCA Statement No. 2, page 27, lines 10-12) rated corporate bonds.

Q. BASED ON THE EXPERIENCE OF THE ACCOUNTING PANEL, DOES A COMPANY'S SIZE HAVE MORE OF AN IMPACT ON ITS ABILITY TO FINANCE CORPORATE BONDS IN FINANCIAL MARKETS THAN ITS CREDIT RATING?

A. Yes. As we will discuss later in our testimony, small corporations like PCLP are limited in their ability to issue corporate bonds in financial markets, because their debt issues do not meet the minimum size requirements. As a result, historically small companies have been limited to mortgage-style financing through banks. While financing through a bank will generally have lower up-front costs, the rates are generally higher than those large companies can receive in the financial markets. Additionally, since loans from banks normally require companies to re-pay the principal during the term of the loan, borrowers must continuously borrow additional funds to both support their construction program and to repay loan principal because they do not generate enough cash from operations to fund both. Pike struggled to secure cash needed to fund its LTIIP projects. The problem that small utilities face having conventional mortgage-style financing is that bank debt must be fully amortized over a 10-year period, while funds borrowed to construct depreciable assets are included in the revenue requirement over periods as long as 60 years. This mismatch between loan amortization and the recovery of capital expenditures in rates places the utility company in a precarious cash position after several rounds of financing transactions.

Q. AS TO MAUREEN L. RENO'S UNSUBSTANTIATED ASSERTION THAT PIKE'S MANAGEMENT HAD MULTIPLE OPPORTUNITIES TO REFINANCE ITS LONG-TERM DEBT IN PRIOR YEARS WHEN INTEREST RATES FOR BB-CREDITS WERE SIGNIFICANTLY LOWER, WHEN DID THE COMPANY SEEK OUTSIDE ASSISTANCE TO REFINANCE ITS DEBT?

A. The Company started working with Wedbush Securities, Inc. ("Wedbush") in 2023 through Argo Infrastructure Partners, who acquired Pike's parent company Corning Energy Corporation, on July 6, 2022. PCLP believes that since it was acquired by Corning Energy Corporation, due to its small size, it was, and still is, on a stand-alone basis, unable to refinance its corporate debt. Further, prior to its acquisition by Argo in 2022, Pike, Corning Energy Corporation ("CEC"), and all of its other subsidiaries were unable to refinance their consolidated debt in the private investor market place. Shortly after its acquisition by Argo in July of 2022, CEC began the process of refinancing its debt in the private lender market. This project was made possible by Argo, who has completed such transactions for its other investee companies. The Company solicited bids from several investment banking firms, including PNC Bank, Bank of America, Scotia Bank, and Citizens Bank/Wedbush. Following several months of discussions with these investment banks, Wedbush (together with Citizens JMP Securities) was engaged by Pike's parent company, CEC, to arrange $70,000,000 in long-term debt financing. Wedbush had experience working with investor-owned utilities for over 30 years to manage over 75 debt and preferred stock private placement transactions for investor-owned utilities in over 20 states. CEC chose Wedbush because Wedbush proposed to secure debt refinancing at the CEC level rather than at the operating subsidiary level. This approach was critical to CEC because it allowed the Company to refinance all of its debt without having operating subsidiary debt secured by utility company operating assets. Other investment banking firms recommended that Corning refinance its debt at the operating subsidiary level. It remained unclear whether Pike's debt and Leatherstocking's debt could have been refinanced separately, due to their size. Prior to seeking bids from investor purchasers of CEC debt, CEC engaged the services of Kroll to rate the Company's bonds. Kroll is a nationally-recognized rating agency that provides debt rating services to smaller companies. After a rigorous process, Kroll arrived at an investor-grade rating of CEC's bonds. With an investor-grade rating in hand, Wedbush sought bids from more than 30 potential purchasers of CEC consolidated debt. Wedbush received competing bids from Prudential and Blackrock. Both firms were willing to purchase all $70 million of CEC's notes. Both Prudential and Blackrock offered competitive interest rates. The Company decided to split its debt offering equally between Prudential and Blackrock in order to establish a relationship with both lenders. Because this transaction was the Company's first private lender transaction, the Company believed it was strategically wise to develop a relationship with both lenders, so as to maximize future financing opportunities. Blackrock's proposed interest rate was slightly higher than Prudential's, but the Company and Wedbush were able to negotiate with Blackrock to reduce their interest rate to equal Prudential's interest rate. Blackrock was unwilling to purchase CEC debt for a period in excess of 10 years. Accordingly, the Series A notes of $50 million for a 10-year period was split equally between Prudential and Blackrock, while Prudential purchased all $20 million of CEC debt. Upon completion of its refinancing, CEC loaned funds to Pike to enable Pike to repay its long-term debt to M&T Bank. CEC's loan to Pike is at the same interest rate as CEC's debt to its external lenders.

The Accounting Panel notes that it takes exception to Maureen L. Reno's statement that the Company has had multiple opportunities to refinance its debt over the last several years. In fact, based on the opinion of Wedbush Securities, Pike was unable to refinance its debt in the private lender market at any time prior to its having been acquired by Argo. In terms of establishing a market rate for its long-term debt, CEC did just that. It solicited bids from more than 30 potential lenders, and it received only two bids. The bids were independently offered by Blackrock and Prudential. While the interest rates offered by both investors were similar, they were not identical. CEC did its very best to assure that it obtained the best possible terms and conditions for its refinanced debt, given its size. While Maureen L. Reno may have the advantage of 20-20 hindsight, financial conditions have been on a roller coaster since the Pandemic and Pike's relatively small size limited its opportunities to gain access to financial markets. Additionally, the Company made debt refinancing its highest priority, beginning shortly after Argo's July 6, 2022 acquisition. Because Corning Energy Corporation had never undertaken a transaction of this scope and magnitude, and considering all of the steps that were needed in order to complete this refinancing transaction, completing the transaction within two years of Argo's acquisition was a major accomplishment for the Company.

Q. WHAT STEPS DID CEC'S BROKER WEDBUSH SECURITIES TAKE IN ARRANGING FOR THE ISSUANCE OF DEBT WITH BLACKROCK AND PRUDENTIAL?

A., Please refer to the letter sent by Wedbush to the Company included as Exhibit AP-1R for an outline of the steps they followed to secure the financing by Blackrock and Prudential. The letter highlights some of the difficulties in trying to finance amounts less than $100 million in the private placement market and their view that publicly-issued debt would have required an offering of at least $400 million. These factors, in addition to the fact that only two investors out of more than 30 companies were even willing to submit a bid, disproves Maureen L. Reno's assertion that the Company should have been able to refinance earlier.

<u>**WEATHER NORMALIZATION ADJUSTMENT**</u>

Q. IN PIKE GAS STATEMENT NO. 2, PAGE15 LINES 15-17, THE ACCOUNTING PANEL PROPOSED TO IMPLEMENT A WEATHER NORMALIZATION ADJUSTMENT ("WNA") FOR RESIDENTIAL CUSTOMERS. PLEASE DISCUSS THE OBJECTIONS RAISED TO A WNA BY I&E WITNESS ETHAN H. CLINE (I&E STATEMENT 3, PAGES 3-12) AND HOW THE COMPANY WOULD

ADDRESS THEM IN ORDER TO HAVE THE MECHANISM APPROVED BY THE COMMISSION.

A. The testimony of I&E witness Ethan H. Cline expressed a number of concerns with the Company's proposal to implement a WNA, which centered primarily around building in safeguards for customers. First, he recommended that if the Commission allows the Company to implement a WNA, there should be a 3.0% deadband (I&E Statement 3, pages 12 – 13). While not discussed in the Accounting Panel testimony, the Company does not object to a 3.0% deadband as a condition for implementing the WNA.

In addition, I&E witness Ethan H. Cline raised the following questions on page 8 of his testimony that were contained in the Commission's Final Policy Statement Order in Docket No. M-2015-2518883 that we have addressed below:

Q. HOW DOES THE RATEMAKING MECHANISM AND RATE DESIGN ALIGN REVENUES WITH COST CAUSATION PRINCIPLES AS TO BOTH FIXED AND VARIABLE COSTS?

A. The WNA uses the tail block rates for residential customers. Fixed and variable costs are recovered in both the customer charge and in the tail block rates. The WNA is designed to pass back or recover costs contained in the tail blocks. If the customer charges were increased to only recover fixed costs, there would not be a need for a WNA, they would all be recovered in the customer charge.

Q. HOW DOES THE RATEMAKING MECHANISM AND RATE DESIGN LIMIT OR ELIMINATE DISINCENTIVES FOR THE PROMOTION OF EFFICIENCY PROGRAMS?

A. The WNA uses the customer's actual consumption in the calculation. To the extent that a customer has installed more energy efficient equipment, their energy usage would be less and their WNA adjustment smaller than customers that have not installed more energy efficient equipment.

Q. HOW DOES THE RATEMAKING MECHANISM AND RATE DESIGN IMPACT CUSTOMER INCENTIVES TO EMPLOY EFFICIENCY MEASURES AND DISTRIBUTED ENERGY SOURCES?

A. As indicated in the previous response, customers with more energy efficient equipment will have a smaller WNA adjustment than customers that do not have such equipment, because their calculation is based on their actual energy usage. A smaller WNA adjustment is an incentive to employ energy efficiency measures.

Q. WHETHER THE ALTERNATIVE RATEMAKING MECHANISM AND RATE DESIGN INCLUDE APPROPRIATE CONSUMER PROTECTIONS.

A. The 3.0% deadband recommended by I&E witness Ethan H. Cline and adopted by the Commission for several other utilities in rate case filings should greatly limit the size and dollar amount of any WNA adjustments during the winter heating season.

Q. WHETHER THE ALTERNATIVE RATEMAKING MECHANISM AND RATE DESIGN ARE UNDERSTANDABLE TO CUSTOMERS.

A. WNA mechanisms have been adopted for a number of gas companies in different States by their Regulatory Commissions. While PCLP believes the basic concept of a WNA should be understandable by all customers, the Company agrees that the actual mechanics involved in the calculation of the WNA and other portions of a customer bill may not always be readily understood by all customers. Ratemaking concepts in general are not always readily understood by customers. That is the nature of complex issues like ratemaking.

Q. I&E WITNESS ETHAN H. CLINE (I&E STATEMENT 3, PAGE 5, LINES 3-8) DISCUSSED HOW THE BUDGET BILLING PROGRAM IS A BETTER METHOD FOR CUSTOMERS TO MANAGE THEIR BILLS THAN A WNA. DOES THE ACCOUNTING PANEL AGREE?

A. While the Accounting Panel agrees that the budget billing program allows customers to better budget and spread the cost of their monthly energy usage over the course of a year, the WNA mechanism functions differently. The WNA mechanism would lower customer bills during colder than normal periods of weather to ensure that they do not pay too much for service. Conversely, it will increase their bill during warmer than normal weather to mitigate the impact of lost sales to the Company so it can recover its fixed costs. Budget billing working in conjunction with the WNA would produce more normalized bills over a course of years.

Q. PLEASE DISCUSS THE OBJECTIONS RAISED TO A WNA BY OCA WITNESS KARL RICHARD PAVLOVIC (OCA STATEMENT 3, PAGES 30) AND HOW THE COMPANY WOULD ADDRESS THEM IN ORDER TO HAVE THE MECHANISM APPROVED BY THE COMMISSION.

A. OCA witness Karl Richard Pavlovic cited several reasons for opposing the Company's request for a WNA. First, he stated that a WNA "will provide no benefit to residential customers." The Company disagrees with this statement, because weather will vary from the historical average temperatures ("Normal") each year. When weather is warmer than Normal, the Company would surcharge customers to recover lost revenues and when it is colder than Normal, the Company would reduce revenues billed to customers on a real time basis. Moreover, the WNA provides the Company with a full and fair opportunity to earn the revenue requirement the Commission allows. With frequently fluctuating and warmer weather conditions, this means the Company should be able to go longer between rate cases all else equal, which is certainly a benefit to customers.

His second objection was that a WNA does not meet a legitimate financial need of PCLP. Again, the Company disagrees with this statement. PCLP is required to invest in infrastructure and incurs fixed operating costs to provide safe and reliable distribution services to customers that are not impacted by weather. To the extent it does not recover its fixed costs, PCLP's financial position suffers and, as discussed earlier, the cost of financing its operations will increase. The WNA simply provides PCLP with a full and fair opportunity to earn the revenue requirement the Commission allows. It recognizes that volumetric rates are simply a mismatch in recovering fixed costs and lead to inefficient outcomes when variables impacting volumes consumed which have no relationship to fixed costs disallow full recovery of fixed costs.

OCA witness Karl Richard Pavlovic's third objection was that a WNA will reduce PCLP's incentive to seek efficiency savings in its operations. The Company also disagrees with this argument because a WNA is neither an incentive nor disincentive to seek operating efficiency savings. PCLP is always focused on trying to find efficiency savings in its operations. To the extent that the Company can reduce its operating costs without impacting the level of service provided to customers, it can extend the period of time between rate case filings. The WNA will have no impact on the Company's drive to achieve efficiencies where prudent.

Q. DID OCA WITNESS KARL RICHARD PAVLOVIC (OCA STATEMENT 3, PAGE 30) HAVE ANY RECOMMENDATIONS FOR THE COMMISSION SHOULD IT CONSIDER APPROVING A WNA FOR THE COMPANY?

A. Yes. OCA witness Karl Richard Pavlovic recommended that if the Commission authorizes a WNA for Pike Gas, the Commission should direct that the authorized WNA exclude the proposed "Heat Sensitivity Factor" and include a deadband of 5%.

Q. WHAT IS THE COMPANY'S POSITION REGARDING THE TWO RECOMMENDATIONS OF OCA WITNESS KARL RICHARD PAVLOVIC TO EXCLUDE THE HEAT SENSITIVITY FACTOR AND INCLUDE A DEADBAND OF 5.0%?

A. The "Heat Sensitivity Factor" proposed by the Company is an attempt to make the WNA calculation more accurate by trying to model the real impact of weather on a customer's usage patterns and eliminate the impact of non-weather sensitive usage. PCLP is willing to eliminate this proposal and use the same mechanism that is currently in place for several other utilities in Pennsylvania if the Commission decides PCLP's proposed Heat Sensitivity Factor does not provide a more meaningful WNA adjustment for customers.

Regarding Mr. Pavlovic's recommendation that the Commission include a deadband of 5.0%, the Company believes a deadband this large would negate any value of a WNA. As indicated previously, the Company believes that a deadband of 3.0%, which the Commission has approved for several other gas utilities in Pennsylvania, is more appropriate and will provide reasonable protections for both customers and the Company.

Q. PLEASE DISCUSS THE TABLE INCLUDED IN THE TESTIMONY OF KARL RICHARD PAVLOVIC (OCA STATEMENT 3, PAGE 28).

A. The table included with Mr. Pavlovic's testimony shows the impact that a WNA adjustment would have had on Pike customers during the 2023-2024 heating season if it had been in effect with no deadband. In total, customers would have paid $76,716 more in their gas bills over an eight-month period or an average of $62.88 per customer ($76,716 / 1,220 customers).

Q. WHAT WAS THE ACTUAL RATE OF RETURN THAT PIKE GAS EARNED FOR THE TWELVE MONTHS ENDING SEPTEMBER 30, 2024, AND WHAT WOULD IT HAVE BEEN WITH THE ADDITIONAL $76,716 OF WNA REVENUES?

A. As shown in column 1 of our Exhibit G-4, Summary, Page 1 of 3 (Pike Gas Statement 2), the overall rate of return was 3.34%. The additional $76,716 of revenues would have produced a rate of return of 4.14%, still far less than the Company needs to sustain its gas operations.

Q. HOW HAS "CLIMATE CHANGE" IMPACTED THE FACTORS USED TO CALCULATE "NORMAL WEATHER"?

A. The calculations of "Normal Weather" are based on 30 to 40 years of historical temperatures. More recent data suggests that average temperatures are increasing. Using longer term weather patterns would appear to understate the impact of climate change in determining normal weather that are used in WNA calculations.

Q. DID PIKE GAS REFLECT AN ADJUSTMENT TO "WEATHER NORMALIZE" ITS SALES AND ASSOCIATED REVENUES FOR THE FUTURE TEST YEAR?

A. Yes. As shown on Pike Gas Statement No. 2, Exhibit G-5, Schedule 5, the Company added 154,703 CCFs to its sales forecast for the twelve months ending September 30, 2025. This was equivalent to $91,543 of base revenues as shown on Statement No.1, Exhibit G-6, Schedule PMN-4-G, page 20 of 28. The Weather Normalization adjustment considered the impact of the actual weather vs. normal heating degree days experienced in the Historic Test Year.

Q. DID I&E WITNESS ETHAN H. CLINE OR OCA WITNESSES KARL RICHARD PAVLOVIC OR JENNIFER L. ROGERS ELIMINATE THE COMPANY'S WEATHER NORMALIZATION ADJUSTMENT AS PART OF THEIR ARGUMENTS TO DISALLOW THE COMPANY'S REQUEST FOR A WNA.

A. No. The Company WNA adjustment was not discussed by any of the aforementioned witnesses. In response to Pike County Light and Power's Set 2 Interrogatory included as

Exhibit AP-2R, Jennifer L. Rogers stated that the amount of a WNA adjustment in a hidden row in Exhibit G-4 Summary was 0.

Q. HOW DID THE COMPANY REFLECT THE WNA ADJUSTMENT IN EXHIBIT G-4, SUMMARY?

A. Schedules 4 and 5 of Exhibit G-5 contain the Accounting Panel's forecast of all gas revenues and sales respectively for the twelve months ending September 30, 2025 and includes the WNA adjustment of $91,543. The information from these Schedules is summarized on Schedule 1 of Exhibit G-4 and shown on the first line of Exhibit G-4, Summary. The hidden line referred to by OCA witness Jennifer L. Rogers in the response to Pike County Light and Power's Set 2 Interrogatory was redundant and was therefore not utilized and hidden.

Q. WHAT IS THE COMPANY'S POSITION REGARDING THE $91,543 WNA ADJUSTMENT?

A. The Company believes that to the extent both I&E and OCA witness would disallow the Company's request for a Weather Normalization Adjustment, then they should have removed the $91,543 WNA revenue adjustment from the gas revenue requirement calculation. If the Commission allows the adoption of a Weather Normalization Adjustment mechanism, then the $91,543 adjustment is appropriate.

Q. DOES THIS CONCLUDE YOUR UPDATE / REBUTTAL TESTIMONY?

A. Yes, it does.

APPENDIX A Rebuttal

						Pike AP-G Update
						Schedule 1
Pike County Light & Power Company, Inc.						
Gas Rate Cast R-2024-3052357						
Summary of Revenue Requirement Updates						
	12 mos. Ended September 30, 2025	April 30, 2025 Update Adjustments		12 mos. Ended September 30, 2025	Updated Revenue	As Adjusted for Additional
	As Filed	Reference	Amount	April Update	Requirement	Rrevenue
Operating Revenues:						
Sales of Gas - Base Rate Revenue	$ 2,257,800	Sch. 4	(97,800)	$ 2,160,000	$ 975,700	$ 3,135,700
Weather Normalization	-			-		-
Other Operating Revenues	1,400		-	1,400	-	1,400
Total Operating Revenues	2,259,200		(97,800)	2,161,400	975,700	3,137,100
Operating Expenses:						
Purchased Gas Expense	1,135,000			1,135,000	-	1,135,000
Other Operation and Maintenance Expense	694,100	Sch.5	(30,000)	656,300	2,700	659,000
		Sch.5	(7,800)			
Depreciation & Amortization Expense	333,100	Sch.6	(33,279)	299,821	-	299,821
			-			
Taxes other than Income	27,700		-	27,700	-	27,700
Total Operating Expenses	2,189,900		(71,079)	2,118,821	2,700	2,121,521
Operating Income Before Income Taxes:	69,300		(26,721)	42,579	973,000	1,015,579
State Income Tax	(56,000)	Sch. 12	33,200	(22,800)	77,700	54,900
Federal Income Tax	(135,400)	Sch. 12	88,700	(46,700)	188,000	141,300
Operating Income after Taxes	$ 260,700		$ (148,621)	$ 112,079	$ 707,300	$ 819,379
Rate Base	$ 10,679,042	Sch. 3	$ (1,141,370)	$ 9,537,672	$ -	$ 9,537,672
Rate of Return	2.44%			1.18%		8.59%

Pike AP-G Update
Schedule 2

Pike County Light And Power Company, Inc.
Gas Rate Cast R-2024-3052357
Calculation of Electric Revenue Requirement
For the Twelve Months Ended September 30, 2025

			As Filed Amount	Update Adjustments	As Adjusted
Rate Base at September 30, 2025			$ 10,679,042	$ (1,141,370)	$ 9,537,672
x Rate of Return at September 30, 2025			8.59%	8.59%	8.59%
Total Return Required			917,330	(98,044)	819,286
Total Earned Return			260,700	(148,621)	112,079
Addition Return Required			656,630	50,577	707,207
Multiplied by Retention Factor*			1.3796	1.3796	1.3796
Total Revenue Requirement			$ 905,892	$ 69,777	$ 975,668
Rounded			$ 905,900	$ 69,800	$ 975,700
*	Retention Factor:				
	Additional Revenue	100.0000	$ 905,900	69,800	975,700
	Less: Revenue Taxes -- N/A	-	-	-	-
	Less: Uncollectibles	0.280	2,500	200	2,700
		99.7200	903,400	69,600	973,000
	Less: State Income Tax @ 7.99%	7.9676	72,200	5,600	77,700
		91.7524	831,200	64,000	895,300
	Less: Federal Income Tax @ 21%	19.2680	174,500	13,400	188,000
	Retention Factor	72.484	$ 656,700	50,600	707,300

Statement No. 2-R

Pike AP-G Update
Schedule 3

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Electric Rate Base
At September 30, 2025

Description	Actual Per Books at 09/30/24	Difference Between Historical and Future Years: Reference	Difference Between Historical and Future Years: Amount	As Filed Future Year at 09/30/25	April 30, 2025 Update Adjustments: Reference	April 30, 2025 Update Adjustments: Amount	Future Year at 09/30/25
	(a)	(b)	(c)	(d)=(a)+(c)	(b)	(c)	(d)=(a)+(c)
Utility Plant:							
Gas Plant in Service	$ 7,193,500	(1a)	$ 4,020,642	$ 11,214,142	Sch. 7	$ (1,189,200)	$ 10,024,942
Common Plant in Service (Allocated)	172,900	(1b)	68,100	241,000	Sch. 7	(12,700)	228,300
Interco plant allocated from Corning Gas (Net)	-	(1c)	41,600	41,600		-	41,600
CWIP not taking interest	453,000	(1d)	(453,000)	-		-	-
Total Utility Plant	7,819,400		3,677,342	11,496,742		(1,201,900)	10,294,842
Utility Plant Reserves:							
Accumulated Provision For Depreciation							
of Gas Plant in Service	569,700	(2a)	185,400	755,100	Sch. 8	(86,600)	668,500
of Common Plant in Service (Allocated)	199,300	(2b)	(900)	198,400	Sch. 8	(1,830)	196,570
Total Utility Plant Reserves	769,000		184,500	953,500		(88,430)	865,070
Net Plant	7,050,400		3,492,842	10,543,242		(1,113,470)	9,429,772
Additions to Net Plant							
Working Capital Requirements:							
Cash Working Capital	(24,600)	(3)	143,400	118,800	Sch. 9	16,000	134,800
Materials and Supplies	271,000	(4)	5,800	276,800		-	276,800
Prepayments	5,400	(5)	100	5,500		-	5,500
Deferred Debits (Net of Tax)	16,500	(6)	18,200	34,700	Sch. 10	(34,700)	-
Total Additions	268,300		167,500	435,800		(18,700)	417,100
Deductions to Net Plant:							
Deferred Credits (Net of Tax)	1,600	(7)	(6,000)	(4,400)	Sch. 11	(1,600)	(6,000)
Customer Deposits	58,700	(8)	600	59,300		-	59,300
Accumulated Deferred Income Taxes	255,100	(9)	(10,000)	245,100	Sch. 12	10,800	255,900
Total Deductions	315,400		(15,400)	300,000		9,200	309,200
Gas Rate Base	$ 7,003,300		$ 3,675,742	$ 10,679,042		$ (1,141,370)	$ 9,537,672

Pike AP-G Update
Schedule 4

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Expense Adjustment for Intercompany Charges
For the Twelve Months Ended September 30, 2025

	12 Months Ended 9/30/2024 (1)	Update Adjustments (2)	As Adjusted (3) = (1+2)
12 Months Ended September 30, 2025			
Base Revenue	$ 140,685	$ -	$ 140,685
Delivery Revenue -- Retail Customers	884,160	-	884,160
DSIC Revenue	97,786	(97,786)	-
Rider Revenue (GCR)	1,134,943	-	1,134,943
Total	$ 2,257,574	(97,786)	2,159,788
12 Months Ending September 30, 2024			
Base Revenue	135,453	$ -	$ 135,453
Delivery Revenue -- Retail Customers	757,798	-	757,798
DSIC Revenue	101,956	-	101,956
Rider Revenue (GCR)	1,145,888	-	1,145,888
Total	$ 2,141,095	-	2,141,095
Net Increase / (Decrease) in Revenues	$ 116,479	$ (97,786)	18,693
Rounded	$ 116,500	$ (97,800)	$ 18,700

Pike AP-G Update
Schedule 5

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Expense Adjustment for Intercompany Charges
For the Twelve Months Ended September 30, 2025

Intercompany Charges	12 Months Ended 9/30/2024 (1)	Update Adjustments (2)	As Adjusted (3) = (1+2)
Total Intercompany Charges	$ 780,177	$ (200,000)	$ 580,177
x Pike Electric Share	15%	15%	15%
Intercompany costs Alloc. to Electric	**$ 117,027**	**$ (30,000)**	**$ 87,027**
Total Intercompany Allocations	$ 780,177	$ (780,177)	$ -
x CPI Increase	1.00%	-1.00%	-
Net Change	**$ 7,802**	**$ (7,802)**	**$ -**
Escalation Adjustment Rounded	**$ 7,800**	**$ (7,800)**	**$ -**

Pike AP-G Update
Schedule 6

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Depreciation Expense Adjustment
For the Twelve Months Ended September 30, 2025

	Gas Distribution Plant	Common Plant Allocated	Total Gas
Gas Distribution Plant in Service			
At September 30, 2024	7,193,512	219580	$ 7,413,092
Less: Acquisition Adjustment	-	-	-
Gas Plant at September 30, 2024	7,193,512	219,580	7,413,092
Less: Non-Depreciable Plant	-	(46,650)	(46,650)
Depreciable Plant at September 30,2025	7,193,512	172,930	7,366,442
Additions - October 1, 2024 thru September 30, 2025			
Distribution - Completed CWIP at 9/30/2025	453,042	-	453,042
Distribution / General Additions Plant	2,500,000	90,000	2,590,000
Additions - October 1, 2025 thru March 31, 2026			
Distribution / General Additions	-	-	-
Total Additions	2,953,042	90,000	3,043,042
Retirements - October 1, 2024 thru September 30, 2025			
Distribution / General Plant	(121,600)	(34,600)	(156,200)
Retirements - October 1, 2025 thru March 31, 2026			
Distribution / General Plant	-	-	-
Total Retirements	(121,600)	(34,600)	(156,200)
Gas Depreciable Plant at September 30, 2025	10,024,954	228,330	10,253,284
x Book Basis Average Composite Depreciation Rate	2.629%	15.866%	2.924%
Calculated Accruals to Depreciation Expense			
For The Twelve Months Ended September 30, 2025	263,556	36,227	299,783
Less: Depreciation Expense as Filed	294,820	38,242	333,062
Decrease In Depreciation Expense	$ (31,264)	$ (2,015)	$ (33,279)

Pike AP-G Update
Schedule 7

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Post Test Year Plant Additions
For the Twelve Months Ended September 30, 2025

	GAS PLANT IN SERVICE	Company January 2025 Filing	April Update Adjustments	April 30, 2025 Update Filing
1	Electric Plant In Service - 9/30/2024	$ 7,193,500	$ -	$ 7,193,500
2	Additions - Completed CWIP - 9/30/2025	453,042	-	453,042
3	Additions - 10/1/2024 - 9/30/2025	2,500,000	-	2,500,000
4	Additions - 10/1/2025 - 8/30/2026	1,250,000	(1,250,000)	-
5	**Total Plant**	**$ 11,396,542**	**$ (1,250,000)**	**$ 10,146,542**
6	Retirements 10/1/2024 -9/30/2025	(121,600)	-	(121,600)
	Retirements 10/1/2025 -9/30/2026	(60,800)	60,800	-
7	**Total Retirements**	**$ 11,214,142**	**$ (1,189,200)**	**$ 10,024,942**
	COMMON PLANT ALLOCATED TO GAS			
8	Gas Common Plant In Service - 9/30/2024	$ 1,152,869	$ -	$ 1,152,869
9	**Allocated to Gas - 15%**	**$ 172,930**	**$ -**	**$ 172,930**
10	Additions - Completed CWIP - 9/30/2024	-	-	-
11	Additions - 10/1/2024 - 9/30/2025	600,000	-	600,000
12	Additions - 10/1/2025 - 8/30/2026	200,000	(200,000)	-
13	Electric Plant Additions - 12/31/2021	$ 800,000	$ (200,000)	$ 600,000
14	**Allocated to Gas - 15%**	**$ 120,000**	**$ (30,000)**	**$ 90,000**
15	Retirements 10/1/2024 -9/30/2025	(230)	-	(230)
	Retirements 10/1/2025 -9/30/2026	(115,300)	115,300	-
16	**Allocated to Electric - 15%**	$ (17,330)	$ 17,295	$ (35)
17	**Gas Common Plant In Service - 12/31/2021**	**$ 275,601**	**$ (12,705)**	**$ 262,896**
	Rounded	**$ 275,600**	**$ (12,700)**	**$ 262,900**

Pike AP-G Update
Schedule 8

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Post Test Year Plant Additions - Accumulated Depreciation
For the Twelve Months Ended September 30, 2025

	ACCUMULATED DEPRECIATION	Company January 2025 Filing	April Update Adjustments	April 30, 2025 Update Filing
1	**Gas Reserve Balance - 9/30/2024**	**$ 569,700**	**$ -**	**$ 569,700**
2	Additions - 10/1/2024 - 9/30/2025	$ 220,400	$ -	$ 220,400
3	Additions - 10/1/2025 - 8/30/2026	147,400	$ (147,400)	$ -
4	Total Electric Reserve	$ 367,800	$ (147,400)	$ 220,400
	Retirements 10/1/2024 -9/30/2025	$ (121,600)	$ -	$ (121,600)
5	Retirements 10/1/2025 -9/30/2026	$ (60,800)	$ 60,800	$ -
6	**Net Additions**	**$ 185,400**	**$ (86,600)**	**$ 98,800**
7	**Gas Reserve Balance - 9/30/2025**	**$ 755,100**	**$ (86,600)**	**$ 668,500**
8	**Common Electric Reserve Balance - 9/30/2024**	**$ 1,328,583**	**$ -**	**$ 1,328,583**
9	**Allocated to Gas - 15%**	**$ 199,287**	$ -	**$ 199,287**
	Rounded	**$ 199,300**	**$ -**	**$ 199,300**
10	Additions - 10/1/2024 - 9/30/2025	$ 212,200	$ -	$ 212,200
11	Additions - 10/1/2025 - 8/30/2026	$ 127,500	$ (127,500)	$ -
12	Total Common Additions to Electric Reserve	$ 339,700	$ (127,500)	$ 212,200
13	**Allocated to Gas - 15%**	**$ 50,955**	**$ (19,125)**	**$ 31,830**
	Rounded	**$ 51,000**	**$ (19,100)**	**$ 31,800**
	Retirements 10/1/2024 -9/30/2025	$ (230,600)	$ -	$ (230,600)
	Retirements 10/1/2025 -9/30/2026	$ (115,300)	$ 115,300	$ -
14	**Allocated to Gas - 15%**	**$ (51,885)**	**$ 17,295**	**$ (34,590)**
	Rounded	**$ (51,900)**	**$ 17,300**	**$ (34,600)**
15	**Common Electric Ending Balance - 9/30/2025**	**$ 198,415**	**$ (1,830)**	**$ 196,510**
16	Lines 18, 23, 26)			
17	**Total Gas Reserve Balance - (**Lines 15, 28)	**$ 953,515**	**$ (88,430)**	**$ 865,010**

Pike AP-G Update
Schedule 9

Pike County Light And Power Company, Inc
Gas Rate Cast R-2024-3052357
Cash Working Capital Adjustment for Intercompany Charges
For the Twelve Months Ended September 30, 2025

	Reference	Amount	(Lead) / Lag Days	Dollar Days
Revenue Recovery	Sch. 1	3,373,900	21.3	$ 71,796,592
Gas Supply Expenses:	Sch. 2	1,135,000	10.0	11,338,650
Pike Salaries & Wages	Sch. 3	291,667	8.0	2,333,336
401K Pension Match	Sch. 3	6,499	8.0	51,993
Employee Welfare Expenses	Sch. 5	82,889	23.0	1,906,444
Intercompany Charges	Sch. 6	80,397	30.0	2,411,897
Uncollectible Accounts Accrual	Sch. 7	6,175	8.0	49,400
Other O&M	Sch. 8	163,995	23.0	3,771,895
Amortizations:	Sch. 4			-
Rate Case Costs		9,400	-	-
PUC Assessment		4,978	-	-
Insurance		13,500	-	-
Depreciation & Amortization	Sch. 4	333,100	-	-
Taxes Other - Payroll	Sch. 9	27,700	11.0	304,700
- Property Tax		-	-	-
Income Taxes:				-
Federal Income Tax	Sch. 10	10,440	30.0	313,200
Deferred Federal Income Tax	Sch. 4	(10,440)	-	-
Corporate Business Tax (State)	Sch. 11	3,972	30.0	119,160
Deferred Corporate Business Tax		(3,972)	-	-
Return on Invested Capital	Sch. 4	1,077,000	-	-
Total Requirement		3,232,300	7.0	22,600,674
Net Lag		$ 3,270,100	14.3	49,195,918
Net Requirement (Net Lag / 365)				$ 134,783
Historical Cash Working Capital				118,831
Net Change				$ 15,952
Rounded				$ 16,000

			Pike AP-G Update
			Schedule 10

Pike County Light And Power Company, Inc.

Gas Rate Cast R-2024-3052357

Adjustment to Eliminate Storm Rate Case Costs from Rate Base

For the Twelve Months Ended September 30, 2025

Deferred Debits - RATE CASE COSTS	12 Months Ended 9/30/2024 (1)	Update Adjustments (2)	As Adjusted (3) = (1+2)
Rate Case Costs - 9/30/2024	$ 22,854	$ (22,854)	$ -
Spending 9/30/2024 - 9/30/2025	37,500	(37,500)	-
Balance at 9/30/2025	**60,354**	**(60,354)**	**-**
Amortization - 9/30/2024 - 9/30/2025	(12,379)	12,379	-
Balance at 9/30/2025	**47,975**	**(47,975)**	**-**
After Tax Balance	**34,682**	**(34,682)**	**-**
Rounded	**$ 34,700**	**$ (34,700)**	**$ -**

			Pike AP-G Update
			Schedule 11

Pike County Light And Power Company, Inc.

Gas Rate Cast R-2024-3052357

Adjustment to Correct Rate Base Deduction for Deferred Credits (TCJA Tax Benefits)

For the Twelve Months Ended September 30, 2025

Deferred Credit Items (As Filed)	FIT Tax Rate Change Accts. 253912 & 253922	After Tax *	Rounded
Negative Deferred Credit Balance as of September 30, 2024	$ 2,275	$ 1,644	$ 1,600
Deferred Credits 10/1/2024 - 9/30/2025	-	-	-
Less: Amortization of Deferred Charges 10/1/2024 - 9/30/2	(8,303)	(6,003)	(6,000)
Negative Deferred Credit Balance as of September 30, 2025	$ (6,029)	$ (4,358)	$ (4,400)

Deferred Credit Items (April 2025 Update)	FIT Tax Rate Change Accts. 253912 & 253922	After Tax *	Rounded
Negative Deferred Credit Balance as of September 30, 2024	$ 2,275	$ -	$ 2,300
Deferred Credits 10/1/2024 - 9/30/2025	-	-	-
Less: Amortization of Deferred Charges 10/1/2024 - 9/30/2	(8,303)	-	(8,300)
Negative Deferred Credit Balance as of September 30, 2025	$ (6,029)	$ -	$ (6,000)
Net Change			$ (1,600)

Pike County Light And Power Company, Inc.
Gas Rate Cast R-2024-3052357
Adjustment to State Income Taxes
For the Twelve Months Ended September 30, 2025

	STATE ELECTRIC INCOME TAXES	September 30,2024 As Filed	Update Adjustments	As Adjusted
1	Operating Income Before Income Taxes	$ 69,300	$ (26,721)	$ 42,579
2	Less: Interest Expense	769,959	(442,817)	327,142
3	**Income Before Federal Income Tax**	**(700,659)**	**416,096**	**(284,563)**
	Add:			
4	Book Depreciation	333,100	-	333,100
5	Amortization of Rate Case Expenses	9,400	-	9,400
6	Amortization of Def. Purchased Gas Cost	-	-	-
7	**Total**	**342,500**	**-**	**342,500**
	Deduct:			
8	Tax Depreciation	255,285	-	255,285
9	Deferred Rate Case Expense	37,500	-	37,500
10	Deferred Storm Costs	-	-	-
11	Amortization - Deferred FIT Customer Cr.	-	-	-
12	**Total**	**$ 292,785**	**$ -**	**$ 292,785**
13	**Taxable Income**	**$ (650,944)**	**$ 416,096**	**$ (234,848)**
14	State Income Tax Rate - 9.99%	7.99%	7.99%	7.99%
15	State Income Tax	$ (52,010)	$ 33,246	$ (18,764)
16	Deferred Income Tax Dr.	23,394	-	23,394
17	Deferred Income Tax Cr.	(27,366)	-	(27,366)
18	**Total State Income Tax**	**$ (55,982)**	**$ 33,246**	**$ (22,737)**
	Rounded	**$ (56,000)**	**$ 33,200**	**$ (22,700)**

Pike AP-G Update
Schedule 12
Page 2 of 3

Pike County Light And Power Company, Inc.
Gas Rate Cast R-2024-3052357
Adjustment to Federal Income Taxes
For the Twelve Months Ended September 30, 2025

	FEDERAL ELECTRIC INCOME TAXES	September 30,2024 As Filed	Update Adjustments	As Adjusted
1	State Taxable Income	$ (650,944)	$ 416,096	$ (234,848)
2	Less: State Income Tax	55,982	(33,246)	22,736
3	Federal Tax Adjustment	-	-	-
4	**Adjusted Taxable Income**	**$ (594,962)**	**$ 382,850**	**$ (212,112)**
5	Federal Income Tax Rate 21.00%	21.00%	21.00%	21.00%
6	**Current Federal Income Tax**	**$ (124,942)**	**$ 80,398**	**$ (44,543)**
	Deferred FIT Applicable To:			
7	Book Depreciation	$ (69,951)	$ -	$ (69,951)
8	Amortization of Rate Case Expenses	(1,974)	-	(1,974)
9	Amortization of Deferred Storm Costs	-	-	-
10	Deferred FIT Customer Cr.	-	-	-
11	Tax Depreciation	53,610	-	53,610
12	Deferred Rate Case Expenses	7,875	-	7,875
13	Amortization of Deferred FIT Customer Cr.	-	-	-
14	**Total**	**$ (10,440)**	**$ -**	**$ (10,440)**
15	Current Federal Income Tax	$ (124,942)	$ 80,398	$ (44,543)
16	Deferred Income Tax - 410	61,485	-	61,485
17	Deferred Income Tax -411	(71,925)	-	(71,925)
18	Amortization of Deferred FIT Customer Cr.	-	8,303	8,303
19	**Total**	**$ (135,382)**	**$ 88,701**	**$ (46,680)**
20	Rounded	**$ (135,400)**	**$ 88,700**	**$ (46,700)**

			Schedule 12
			Page 3 of 3

Pike County Light And Power Company, Inc.
Gas Rate Cast R-2024-3052357
Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2025

	12 Months Ended 9/30/2024 (1)	Update Adjustments (2)	As Adjusted As Adjusted (3) = (1+2)
Rate Base	$ 10,679,042	$ (1,141,370)	$ 9,537,672
Interest Component of Capitalization	7.21%	-3.78%	3.43%
Interest Expense	$ 769,959	$ (442,817)	$ 327,142
Rounded	$ 770,000	$ (442,800)	$ 327,100

Exhibit AP-1R
Letter from Wedbush Securities

April 2nd, 2025
Mr. Chuck Lenns
Chief Financial Officer
Corning Energy Corporation
330 W. William Street
Corning, NY 14830

Dear Mr. Lenns,

Please find below a summary of the refinancing process undertaken by Wedbush Securities on behalf of Corning Energy Corporation.

Wedbush Involvement

The Wedbush team was initially introduced to Corning Energy in late 2023 through Argo Infrastructure Partners, who acquired Corning Energy in 2022. Following several months of discussion, Wedbush Securities (together with Citizens JMP Securities) was engaged by Corning Energy to arrange $70,000,000 in long term debt financing. The Wedbush team's experience working with investor-owned utilities spans over 30 years and during that time the team managed over 75 debt and preferred stock private placement transactions for investor-owned utilities in over 20 states.

Corning Situation Overview Prior to Refinancing

Prior to undertaking the refinancing transaction, Corning had approximately $66 million in outstanding bank borrowings across its three subsidiaries. This debt was broken down between Corning Gas (approximately $42 million in eight separate loans), Pike County Light & Power Company (approximately $18 million in eight separate loans) and Leatherstocking Gas (approximately $6 million in five separate loans). Each of these loans was collateralized by all assets of the applicable subsidiary. Each of these loans had entity level covenants and were subject to significant principal amortization. Corning did not have holding company debt, however it was a guarantor of all subsidiary debt.

For the five years prior to the refinancing, Corning in aggregate had experienced mixed financial performance, with earnings and EBITDA decreasing in each of the three years prior to 2023 and capital expenditures increasing in each year. While the company exhibited slightly improved financial performance in 2024 over prior years, continued improvement was largely contingent on future rate cases and customer growth, neither of which were assured.

Unlike most investor-owned utilities, Corning had never undertaken a private placement transaction, which allows borrowers to access long term, fixed rate financing typically provided by insurance companies. The private placement market allows for terms similar to publicly issued debt, but in amounts significantly less than would be required in a public offering (public offerings typically have a $400 million minimum issue size). While there is no strict minimum deal size to access the private placement market, the average issue in this market is well above

$100 million in size and many investors decline to participate in transactions less than $100 million.

Wedbush Recommendation

Wedbush's recommended approach to the refinancing incorporated the following elements, most of which were achieved in the final financing package:

- Bank vs. Institutional Debt: We observed that Corning's debt was held in its entirety by two bank lenders, M&T Bank and Wayne Bank. The amortizing nature of the company's bank loans meant that the company would need to repay its existing bank loans at the same time as it needed to raise additional debt to fund capital projects costing well in excess of the company's cash flow from operations. Institutional debt would allow Corning, and by extension its subsidiaries, to achieve maturities on its new debt of ten years or more with no amortization.

- Holding Company vs. Subsidiary Issuance: While Corning had been able to arrange subsidiary level bank financing from regional and community banks, in Wedbush's judgement, institutional investors would be unlikely to provide subsidiary level financing due to 1) relatively small size (each had 2024 income of less than $1.5 million) and 2) relatively limited geographic and customer diversification. On the other hand, debt issuance at the holding company was seen as highly advantageous to Corning due to 1) allowing the financing to achieve a size large enough to attract institutional capital, 2) the overall credit quality would improve by allowing creditors to look to a larger and more diversified company, 3) the holding company structure would allow for a more efficient cash management capability by allowing for easier movement of funds among the different entities, and 4) the company would gain flexibility and save on administrative cost by pledging the stock of the subsidiaries rather than requiring asset level security interests.

- Complete vs Partial Refinancing: When looking at whether to refinance all or a portion of Corning's outstanding debt, we decided that a complete refinancing would be more appropriate, instead of carving out the over $28 million of older, low interest debt. Refinancing all outstanding debt was seen as advantageous because of the following reasons. The existing lenders held security interests in all of Corning's operating assets. If any long-term debt remained outstanding, they would never have given up these security interests and potential investors would be unlikely to bid on the bonds under these conditions. Moreover, carving out the low interest debt from this transaction would have reduced the size of the offering to an undesirable amount (as we received feedback from multiple investors that the complete deal was already too small). Without the refinancing transaction, the utilities would need additional traditional bank financing in order to pay for its required capital costs. This financing, based on the Company's most recent construction loans, would have been at interest rates that exceeded 9% and the new loans would have been 10-year amortizing loans. At the same time, the Company's older loans with lower interest rates would continue to amortize, yielding much less in savings associated with lower interest loans. The Company would have increased its high interest borrowings associated with additional traditional bank financing while its lower interest debt provided less savings each year due to the amortization. Delaying refinancing until lower interest debt fully matured would mean that the Company would bear the risk of rising interest rates and increased costs of securing higher interest debt.

- Target Investor Market: The institutional private placement market is dominated by large insurance companies and asset managers. These institutions are looking for debt investments which match the long duration of their liabilities, resulting in an appetite for debt instruments with maturities ranging from five to thirty years. There are over 30 participants active in this market although many have limitations on credit rating, deal size, minimum pricing and other transaction features. We recommended a broad marketing for the transaction in order to maximize interest in the transaction and create competitive tension for the offering.

- Rating: Based on initial soundings we conducted with selected investors, we felt it was imperative to obtain a credit rating for the transaction. We selected Kroll Bond Rating Agency due to their experience in rating smaller utilities, credibility with investors and lower cost compared with the lager rating agencies.

Corning agreed with these recommendations, and, on this basis, we began marketing the transaction in mid-July 2024, hoping to price the transaction at the end of the month.

Marketing Process

- We received ratings from Kroll of BB+ (corporate rating) and BBB- (issue rating, notched higher due to security interest in the subsidiaries). While this meant the issue was technically investment grade, certain investors would place more emphasis on the below investment grade corporate rating and others expressed concern that a single notch downgrade would render the notes below investment grade.

- Investors were requested to provide bids for bullet maturity structures ranging from 10 to 30 years. The bids could be for all or a portion of the transaction and could be for a single or multiple tranches. Bids were requested based on a spread to underlying treasuries equivalent to the proposed maturity, with the understanding that the all-in coupon would be determined at the time of pricing.

- We approached 32 investors and had meaningful engagement with 21 of these institutions. However, by the conclusion of the process, only two institutions (Prudential and BlackRock) were willing to participate in the offering, with each bidding for the entire $70 million offered.

- The declining parties cited several reasons for passing on the transaction, including 1) initial low investment grade rating, raising the possibility that a single notch downgrade would render the notes non-investment grade; 2) recent financial performance, somewhat below industry averages for utility companies; and 3) the offering size and size of the company were quite small relative to other issuers recently in the market.

Participating Investors – Bid Process

- Prudential Insurance – Were prepared to fund the entire issue ($70 million) in one or more tranches based on spreads to treasuries of 235 bps (10 year), 235 bps (for 12 years based on the treasury curve) and 240 bps (for 15 years based on the treasury curve).

- BlackRock – Were prepared to fund the entire issue as a single, ten-year maturity, at a spread of 250 bps.

- When advised of the superior pricing offered by Prudential, BlackRock agreed to lower its 10-year spread to 235 bps. We ended up allocating a $50 million 10-year tranche at a coupon of 6.29% (Prudential and BlackRock each providing $25 million) and a $20 million 12-year tranche at a coupon of 6.37% (all Prudential).

Pricing Analysis

- A slight pricing anomaly existed at the time of pricing as a function of the inverted yield curve. As of the pricing date (August 12, 2024), the three-month SOFR yield was 5.11% while 10-year treasuries yielded 3.94% and the 12-year interpolated treasury yielded 4.02%.

- Concurrent with the note issuance, Corning put in place a $30 million bank revolving credit priced at SOFR + 265 bps. Therefore, Corning's short-term cost of funds would have been 7.75%, nearly 150 basis points higher than the 10-year cost of the fixed rate private placement.

- There were two low triple-B utility bonds which priced relatively close to the Corning pricing date: an issue for Centerpoint Energy (rated Baa3/BBB-) which priced at 295 bps over the 10-year treasury and an issue for Duke Energy (also Baa3/BBB-) which priced at 258 bps over the 10-year. Given these two utilities are significantly larger than Corning and the issues were in a public format rather than a private placement, the pricing on the Corning transaction would appear to be extremely attractive.

Conclusion

In Wedbush's opinion, Corning's decision to refinance its subsidiary level debt was highly appropriate. The company was able to access institutional markets to obtain significantly longer fixed rate term debt financing with no amortization, limited financial covenants and no asset level security at pricing well below what would have been available in the bank market and comparable with much larger public debt offerings.

Very truly yours,

By: Bard Cook (Apr 2, 2025 22:52 EDT)________________

Bard Cook
Managing Director
Head of Debt Markets & Advisory

WEDBUSH SECURITIES INC. 142 W 57th Street, 12th Floor | New York, NY 10019 | (212) 259-6580 | wedbush.com

Corning Energy Corp Refinancing Process.clean

Final Audit Report 2025-04-03

Created:	2025-04-03
By:	Jax Koren (jax.koren@wedbush.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAA1ZbUJaE_INcSqTUSGIN1FWXPkHLaI7O7

"Corning Energy Corp Refinancing Process.clean" History

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Exhibit AP-2R
OCA Response to Pike Set II Data Requests

COMMONWEALTH OF PENNSYLVANIA

DARRYL A. LAWRENCE
Acting Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
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April 24, 2025

Via Electronic Mail Only
Whitney E. Snyder, Esq.
Erich W. Struble, Esq.
HMS Legal LLP f/k/a
Hawke McKeon and Sniscak LLP
501 Corporate Circle, Suite 302
Harrisburg, PA 17110
wesnyder@hmslegal.com
ewstruble@hmslegal.com

Re: Pennsylvania Public Utility Commission
v.
Pike County Light & Power Company- Gas
Docket No. R-2024-3052357

Dear Counsel:

Enclosed please find the Office of Consumer Advocate's Responses to the Interrogatories of Pike County Light & Power, Set 2 to OCA, in this proceeding.

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectfully submitted,
/s/ Jacob D. Guthrie
Jacob D. Guthrie
Assistant Consumer Advocate
PA Attorney I.D. # 334367
Email: JGuthrie@paoca.org

Enclosures

cc: PUC Secretary Matthew L. Homsher (Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

Pennsylvania Public Utility Commission	:	
v	:	Docket No. R-2024-3052357
Pike County Light & Power Company	:	

I hereby certify that I have this day served a true copy of the following document, Responses to the Interrogatories of Pike County Light & Power, Set 2 to OCA, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

Dated this 24th day of April, 2025.

SERVICE BY E-MAIL ONLY

Carrie B. Wright, Esq.
Michael Podskoch, Esq.
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Commonwealth Keystone Building
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Counsel for:
Darryl A. Lawrence
Acting Consumer Advocate

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
717-783-5048

Dated: April 24, 2025

PIKE COUNTY LIGHT & POWER COMPANY – GAS DIVISIONS' INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET II, TO OFFICE OF CONSUMER ADVOCATE

1. Case testimony provided in Pike County Light & Power Company Exhibit G-6, Schedule PMN-4-G presents the complete detailed output of the test period class embedded cost of service. Included on Company Exhibit G-6, Schedule PMN-4-G, Page 20 of 28, the Company calculated the weather normalization adjustment of $91,543, which considered the impact of actual weather vs. normal degree heating days. As such, Pike decreased its rate increase request by $91,543 as shown in the previously mentioned exhibit. Please explain the basis for excluding these revenues from your recommendation contained in direct testimony given the choice to recommend the Commission not approve Pike's proposed weather normalization adjustment.

RESPONSE

Ms. Rogers did not incorporate the $91,543 amount referenced in her recommended revenue requirement because the Company provided no evidence, discussion, or support that this amount relates to the proposed WNA mechanism, and has provided no information in direct testimony on if, how, or why it is incorporated as an adjustment into the cost of service. Ms. Rogers also notes that in the excel spreadsheet of Exhibit G-4, Summary page 1 (provided in response to I&E-RE-4-D), the hidden row 12 explicitly shows a $0 weather adjustment.

Response prepared by the following witnesses:
Jennifer L. Rogers
Karl R. Pavlovic

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company (Gas)	:	

VERIFICATION

I, Jennifer Rogers, hereby state that the facts above set forth in my Responses to Pike Set 2 to OCA, 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 24, 2025

Signature: Jennifer L. Rogers

Jennifer Rogers

Address: 10480 Little Patuxent Parkway,
Suite 300,
Columbia, Maryland, 21044

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket No. R-2024-3052357
v.	:	
Pike County Light & Power Company (Gas)	:	

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Responses to Pike Set 2 to OCA, 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: 4/23/25

Signature: Karl R Pavlovic
Karl R. Pavlovic

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052357
	:	
Pike County Light & Power Company (gas)	:	

Pike County Light and Power Company

Statement No. 3-R

Direct Testimony of

Nancy Karlovich

Date: May 1, 2025

Q. What is your position with the Company?

A. I am the General Manager of Pike County Light and Power Company as of 4/14/2025.

Q. What is your background in the natural gas utility industry?

I have 14 years in the natural gas industry. First working for Precision Pipeline Solutions as a Meter Reader, then a Gas Engineering Technician. From PPS, I moved on to work for Central Hudson Gas & Electric. At CHG&E, I started as a Gas Planner, transferred to role of Gas Compliance Training Coordinator and was then promoted to the role of Gas Foreman. After 7 years of service, I left CHG&E and worked at Consolidated Edison as an Associate in the Gas Construction Management group before transitioning to my current position as General Manager of Pike County Light & Power.

Q. Are you familiar with Pike's Distribution Integrity Management Plan ("DIMP") and related materials?

A. Yes.

Q. Are you familiar with Pike's Long-Term Infrastructure Improvement Plan?

A. Yes.

Q. Have you reviewed Mr. Andrew Hiorth of the Bureau of Investigation and Enforcement's Direct Testimony in this proceeding?

A. Yes. And I testify in response below.

Q. Is the goal of a DIMP to measure scores from year to year?

A. No. As Mr. Hiorth describes in his testimony, the goals of the DIMP are to identify threats, evaluate and rank risks of the threats to the facilities, identify and implement measures to reduce risk, measure performance, monitor results, and evaluate effectiveness, periodically evaluate and make improvements to the program, and reporting.

Q. Does Pike follow these procedures?

A. Yes, and Mr. Hiorth makes no indication the Pike does not follow these procedures.

Q. Do you have any comments regarding Mr. Hiorth's testimony that "the only preventative and mitigative measures that Pike Gas indicated it is implementing are its replacement of cast iron/wrought iron and bare steel pipelines"?

A. Yes. As PHMSA states: "Pipelines constructed of cast and wrought iron, as well as bare steel, are among those pipelines that pose the highest-risk." https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background (updated April 1, 2025). The information Mr. Hiorth was provided regarding Pike's DIMP indicated pipe made of these materials are top risks to Pike's distribution system. Thus, Pike is following the results of its DIMP by focusing its efforts on addressing the biggest risks to its pipeline system. Another very significant risk to all pipelines and another top risk to Pike's pipeline system is third-party excavation damage. Pike submitted discovery in this case, discussed by OCA Witness Rogers indicating that Pike spends significant amounts of money every year educating the public on 811 and Call Before You Dig procedures.

Q. Do you agree with Mr. Hiorth's testimony that Pike is not working to decrease risk in its pipelines in an effective manner?

A. No. Mr. Hiorth looks at a minute snapshot in time that ignores history and planned future replacements to make an unfair determination regarding Pike's efforts at removing ***all*** the cast iron and bare steel from its system by 2030. Here is the whole story, evidenced in publicly available documents that were either produced to Mr. Hiorth or to which he had access through the Commission or PHMSA's website. In 2019, the Commission approved Pike's Long-Term Infrastructure Improvement Plan ("LTIIP"), including modification in 2022. Docket No. P-2019-3007304 (available at https://www.puc.pa.gov/pcdocs/1739815.pdf). The LTIIP explains that prior to 2019, Pike (under previous ownership) planned to replace only 3,000 feet of mains, total, over a 20-year time frame. LTIIP at p.11. Pike's LTIIP significantly accelerated this replacement schedule to removal of all cast and wrought iron and bare steel in an approximately 11-year period. The first step in this project, as explained in the LTIIP, was to overhaul a regulator station which would allow the rest of the system to operate safely as mains would be replaced in the future. LTIIP at 14. The first year also included the replacement of the oldest and riskiest 3,000 feet of cast iron main.

Pike has been steadily working towards completing its LTIIP and removing all of the cast and wrought iron and bare steel from its system and believes it is still on schedule to meet this goal by 2030. At the end of 2018, per Pike's publicly available PHMSA reporting data, Pike had 3.6 miles of bare steel and 6 miles of cast and wrought iron. As of the end of 2024, Pike had 1.87 miles of bare steel and 4.86 miles of cast and wrought iron. Thus, Pike has removed approximately 30% of the cast iron, wrought iron and bare steel pipelines from its system as of the end of 2024, and in addition to that, Pike will be removing the remainder of the Aldyl-a plastic on a neighborhood main replacement project in Matamoras, PA beginning on May 5, 2025. This project will be fully completed before the end of fall 2025 and is further discussed in the following paragraph.

Q. Does Pike plan to complete replacement of all cast and wrought iron and bare steel from its system by the end of 2030?

A. Yes. Pike still plans to meet its LTIIP goals. As indicated in the Annual Asset Optimization Plan ("AAOP") provided in discovery and publicly available, in 2025, Pike will undertake two main replacement projects: Avenues O and P and Bertha Street which consist of approximately 1.7 miles of mains. AAOP at 3. As described in the LTIIP, Bertha Street consists of bare steel replacements. LTIIP at 21. Bertha Street was originally planned to be completed in 2020, but 2020 was a difficult year for projects and contractors due COVID, particularly due to lead times of materials, such as meter bars, regulators and Dresser fittings which had at least a 1-year lead time. Also, labor and material costs significantly increased during Covid, specifically from 2020-2023 and these effects continue to linger into 2025. In addition, local municipal paving, sewer and water main installations and programs have had a history of changing Pike's scheduled work for the following year(s). Another impact that was overlooked by Mr. Hiorth, is that the entire gas service territory had to be surveyed in 2021 in order to apply and get approval for Pike's County Soils permit for the entire area covered by the 11 year GMR program, thus further delaying the project.

Avenues O and P replacements were originally planned for completion 2021 and 2022. Due to the aforementioned reasons, we replaced approximately 50% of the bare steel, cast iron and wrought iron in 2021 on streets O&P. At the end of 2022 we replaced 10 blocks of leak prone pipe (LPP) on Ave K. In 2023 we replaced 11 blocks of LPP on Delaware Dr and in 2024 we replaced 10 blocks of LPP on Ave I. The remainder of O&P and Bertha streets will be 100% complete by September 2025.

Avenues O and P replacements include cast iron, wrought iron and bare steel. Likewise, as indicated in Mr. Hiorth's Exhibit, Pike's response to I&E -PS-13 indicates the specific amounts of cast iron, wrought iron and bare steel that Pike will remove each year through 2030. Pike will keep working each year to remove all cast and wrought iron and bare steel from its system pursuant to its LTIIP. Pike faces numerous challenges in completing these projects including contractor availability and costs, environmental and permitting delays, and requests to work in conjunction with municipal street paving projects. Pike is doing the best it can to prioritize these replacement projects under the real-world circumstances within which it must operate.

Q. Does the Commission review Pike's compliance with its LTIIP each year?

A. Yes. Pike is required to file the AAOP mentioned above every year, which the Commission's Bureau of Technical Services reviews for compliance. On April 8, 2025, the Commission issued a Secretarial Letter finding Pike in compliance with its LTIIP. I have attached that letter, which is publicly available at Docket No. M-2025-3053809 as Exhibit NK-1R.

Q. Does this conclude your rebuttal testimony?

A. Yes. I reserve the right to update this testimony as necessary.

Exhibit NK-1R

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 NORTH STREET, HARRISBURG, PA 17120

IN REPLY, PLEASE
REFER TO OUR FILE

April 8, 2025

Docket No. M-2025-3053809
Utility Code: 122400

WHITNEY E. SNYDER
HMS LEGAL
501 CORPORATE CIRCLE, SUITE 302
HARRISBURG, PA 17110
wesnyder@hmslegal.com

Re: Annual Asset Optimization Plan (AAOP) for Pike County Light & Power Company at Docket No. M-2025-3053809

Dear Whitney E. Snyder,

On March 7, 2025, Pike County Light & Power Company (Pike) filed its Annual Asset Optimization Plan (AAOP) for its gas operations, pursuant to 52 Pa. Code § 121.6.

The Commission's regulations require NGDCs with an approved Distribution System Improvement Charge (DSIC) to file annually an AAOP with the Commission. The AAOP shall be filed 60 days after the prior 12 months of the company's Long-Term Infrastructure Improvement Plan (LTIIP) has expired, and pursuant to this timeframe for each successive AAOP 52 Pa. Code § 121.6(a).

The AAOP must include:

1) A description that specifies all of the eligible property repaired, improved, and replaced in the prior 12-month period under its LTIIP and prior year's AAOP.

2) A description of the eligible property to be repaired, improved, and replaced in the upcoming 12-month period.

The Commission is charged with reviewing each AAOP only to determine whether the utility is in substantial compliance with the repairs, improvements, or replacements of the specific eligible property in its approved LTIIP, for the corresponding 12-month timeframes. 52 Pa. Code § 121.6(d). The Commission has delegated the review of AAOPs to the Bureau of Technical Utility Services (TUS).

Timely Filing
52 Pa. Code § 121.6(a)

A utility with an approved DSIC shall file with the Commission, for informational purposes, an AAO plan. The AAO plan shall be filed annually with the Commission 60 days after the 12 months of its LTIIP has expired and under this time frame for each successive year of the term of the LTIIP.

Pike's AAOP substantially complies with this requirement.

Content

52 Pa. Code § 121.6(b)

An AAO plan must include:

(1) A description that specifies all the eligible property repaired, improved and replaced in the prior 12-month period under its LTIIP and prior year's AAO plan.

(2) A description of the eligible property to be repaired, improved and replaced in the upcoming 12-month period.

Pike's AAOP substantially complies with this requirement.

Substantial Adherence to LTIIP

52 Pa. Code § 121.6(d)

An AAO plan will be reviewed by the Commission only to determine whether the utility is in substantial compliance with the repairs, improvements or replacements of the specific eligible property in its approved LTIIP for the corresponding 12-month time frames.

52 Pa. Code § 121.6(e)

Absent any major modifications to the LTIIP or Commission action to reject an AAO plan within 60 days of its submission to the Commission, the AAO plan will be deemed approved. The Commission may extend its consideration period if necessary.

52 Pa. Code § 121.6(f)

If an AAO plan is rejected by the Commission, the utility will be notified of the plan's deficiencies and actions needed to repair, improve or replace eligible property to bring the utility into compliance with the work schedule in its approved LTIIP. If the utility concludes that it needs to revise its LTIIP to comply with the Commission's determinations, it shall file a petition for modification under § 121.5.

Pike's AAOP states that Pike's actual LTIIP expenditures in 2024 were $1,176,984. This was 30.8% more than the planned expenditures from Pike's LTIIP of $900,000. Pike states that it had actually intended to make additional expenditures, but instead rescheduled one of its projects to 2025.

In its LTIIP, Pike had planned to replace 7,154 feet of main in 2024. Pike's AAOP states that 4,792 feet of main were actually replaced in 2024, which is 33% less than the company's projections in its LTIIP. Pike notes that was due to the aforementioned project that it carried over from 2024 into 2025.

Pike's AAOP shows that while the Company intends to complete approximately the same amount of work described in its LTIIP over the course of the entire LTIIP, Pike is attempting to do larger amounts of projects in the near-term, such that the amount of work remaining will taper off in the later years of the LTIIP. Thus, while we expect that Pike's cost overruns will continue over the next two to three years, these costs should diminish in the last years of the LTIIP.

Compliance with the LTIIP is evaluated on a multiyear basis over the life of the LTIIP. Construction and budget variations in individual years can be expected and it is reasonable to expect that over a multi-year timeframe, much of this variation will be mitigated.

The AAOP does not propose a Major Modification to the company's LTIIP.

Accordingly, Pike's AAOP appears to substantially conform to the schedule set forth in the company's LTIIP.

Conclusion

Upon review of Pike's AAOP filed on March 7, 2025, it appears that the filing substantially complies with the requirements of 52 Pa. Code § 121.6 and it is approved. This approval is contingent upon the possibility that subsequent audits, reviews and inquiries, in any Commission proceeding, may be conducted pursuant to 52 Pa. Code § 121.

If you are dissatisfied with the resolution of this matter, you may, as set forth in 52 Pa. Code § 5.44, file a petition with the Commission within twenty (20) days after the date of this letter. Please direct any questions regarding this filing to Matthew Stewart, TUS, at mattstewar@pa.gov.

Sincerely,

Rosemary Chiavetta

Rosemary Chiavetta
Secretary

cc: Kriss Brown, LAW
Allison Kaster, BIE
Dan Searfoorce, TUS
John Van Zant, TUS

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	DOCKET NO. R-2024-3052357
	:	
Pike County Light & Power Company (gas)	:	

Pike County Light and Power Company
Statement No. 4-R

Rebuttal Testimony of
Christopher M. Wall, Principal
The Brattle Group

Concerning
Fair Rate of Return and Capital Structure

May 1, 2025

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Christopher M. Wall. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

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

A. I am submitting this rebuttal testimony before the Pennsylvania Public Utility Commission ("Commission") on behalf of Pike County Light and Power Company ("Pike" or the "Company"), which is a wholly-owned subsidiary of Corning Energy Corporation ("CEC").

Q. Please describe your education and experience.

A. I hold a B.A. in Mathematics and Economics from Saint Peter's College where I graduated Summa Cum Laude and a Master's degree in Economics from Northeastern University. I have more than ten years of experience consulting in the energy industry and have been involved with a variety of projects, mostly involving cost of capital; cost of service; demand forecasting; and rate design for natural gas, water, and electric utilities in North America. I have been involved in over 100 assignments focused on the determination of the cost of capital for ratemaking purposes. I have also included my resume and a summary of the testimony I have filed in other proceedings in Exhibit CMW-1R.

Q. What is the purpose of your rebuttal testimony.

A. The purpose of my rebuttal testimony is to respond to the direct testimonies of Christopher Keller on behalf of the Bureau of Investigation and Enforcement ("I&E")[1] and Maureen L.

[1] Pennsylvania Public Utility Commission, Docket No. R-2024-3052357, Direct Testimony of Christopher Keller, April 3, 2025 ("Keller Direct Testimony").

Reno on behalf of the Pennsylvania Office of Consumer Advocate ("OCA")[2] regarding the just and reasonable return on equity ("ROE") and the appropriate capital structure for the Company. I have not attempted to respond to every position offered by these witnesses, and the fact that I may not have responded to any particular position or statement made by these witnesses does not indicate my agreement with that position or statement.

Q. Are you sponsoring any exhibits in support of your rebuttal testimony?

A. Yes. I am sponsoring Exhibit CMW-2R through Exhibit CMW-12R, which have been prepared by me or under my direction.

Q. How is the remainder of your rebuttal testimony organized?

A. The remainder of my rebuttal testimony is organized as follows:

- Section II provides a summary and overview of my rebuttal testimony and the important factors to be considered in establishing the authorized ROE for the Company.
- Section III discusses capital market conditions, their effect on the cost of equity, and the comparable return.
- Section IV provides my response to Mr. Keller's cost of equity analyses and recommendations.
- Section V provides my response to Ms. Reno's cost of equity and capital structure analyses and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. What analyses do Mr. Keller and Ms. Reno conduct, and what ROEs are each recommending for the Company in this proceeding.

A. Figure 1 summarizes the respective cost of equity model results, ROE, and capital structure recommendations of these witnesses. Mr. Keller prepares a constant growth Discounted

[2] Pennsylvania Public Utility Commission, Docket No. R-2024-3052357, Direct Testimony of Maureen L. Reno, April 3, 2025 ("Reno Direct Testimony").

Cash Flow ("DCF") analysis and a Capital Asset Pricing Model ("CAPM") analysis; however, Mr. Keller's ROE recommendation of 9.66 percent is based solely on the result of his constant growth DCF analysis.[3] Additionally, Mr. Keller proposes to accept the Company's capital structure composed of 50.63 percent common equity, 40.73 percent long-term debt, and 8.64 percent short-term debt.

Ms. Reno also conducts constant growth DCF and CAPM analyses with her recommended ROE of 9.30 percent based solely on the midpoint of her constant growth DCF analyses while her CAPM analysis, the average of which produces a substantially higher result, is used only as a check on the reasonableness of her constant growth DCF analyses.[4] Ms. Reno proposes to accept the Company proposed capital structure but recommends that Pike's equity ratio of 50.63 percent be "established as a maximum".[5]

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3 Keller Direct Testimony, at 23-24.

4 Reno Direct Testimony, at 7.

5 *Id.,* at 23.

Figure 1: Summary of Mr. Keller and Ms. Reno
Cost of Equity Model Results

	Keller		Reno	
	Low	**High**	**Low**	**High**
Constant Growth DCF				
Proj. EPS Growth Rates	9.56%	9.76%	9.76%	9.84%
Proj. EPS, BVPS & DPS Growth Rates	n/a	n/a	8.83%	8.85%
Sustainable Growth Rate	n/a	n/a	8.71%	8.74%
Midpoint	**9.66%**		**9.27%**	
CAPM	9.05%	11.28%	8.06%	11.24%
Midpoint	**10.17%**		**9.65%**	
Recommended ROE	**9.66%**		**9.30%**	
Capital Structure				
Common Equity	50.63%		50.63%	
Short-term Debt	8.64%		8.64%	
Long-Term Debt	40.73%		40.73%	

Q. What factors should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE?

A. The primary factors that should be considered are: (1) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (2) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; (3) the effect of current and expected capital market conditions; and (4) achieving a reasonable balance between the interests of investors and customers.

Q. What are your key conclusions and recommendations regarding the appropriate ROE and capital structure for the Company?

A. Based on my review of Mr. Keller's and Ms. Reno's direct testimonies, my key conclusions regarding the Company's revised ROE request and capital structure are as follows:

- While I disagree with various aspects of the cost of equity models conducted by Mr. Keller and Ms. Reno in this proceeding, the fundamental issue is that their ROE recommendations do not reasonably reflect the change in market conditions since the completion of the Company's last rate proceeding in 2021.
    - Long-term interest rates have increased 233 basis points since the Commission approved the settlement agreement in the Company's last rate proceeding, which is indicative of a significant increase in the cost of equity since that time.
    - Long-term interest rates are expected to remain elevated during the period in which the rates in this proceeding will be in effect.
    - As a result of the increase in interest rates, the average annual returns for natural gas utilities have increased.
    - Despite the increase in the cost of equity demonstrated by current market conditions, Mr. Keller's recommended ROE of 9.66 percent and Ms. Reno's recommended ROE of 9.30 percent are below the average authorized return for natural gas utilities across the U.S. in 2024 with Mr. Keller's recommended ROE at the very low-end of the range of returns authorized for natural gas utilities in 2024. As a result, both Mr. Keller's and Ms. Reno's recommendations are not reflective of the investor required return for Pike in the current market environment.
- Ms. Reno's ROE recommendation was based on the midpoint of her constant growth DCF analyses which is inconsistent with the process she has employed in prior proceedings.
    - In prior proceedings, Ms. Reno has recognized the effect of the increase in interest rates over the past few years and excluded the low-end of her constant growth DCF results when determining her recommended ROE.
    - Had Ms. Reno determined her recommended ROE consistent with the methodology she has relied on in prior proceedings, her recommended ROE would have increased from 9.30 percent to 9.60 percent.
- Mr. Keller inappropriately excluded Southwest Gas Holdings, Inc. from the proxy group he used to determine his ROE recommended for Pike. Adjusting Mr. Keller's proxy group to include Southwest Gas Holdings, Inc. and updating his constant growth DCF and CAPM analyses to reflect current market data increases Mr. Keller's constant growth DCF result from 9.66 percent to 10.49 percent as well as his average CAPM result from 10.16 percent to 10.72 percent. These updated results provide support for the Company's requested ROE of 10.20 percent.
- When Ms. Reno's analyses are updated to reflect the most current data available and corrected for the issues that I discuss in detail herein, the midpoint of the adjusted constant growth DCF model is 10.45 percent while the midpoint of the

adjusted CAPM is 10.23 percent, each of which is support the Company's requested ROE in this proceeding of 10.20 percent.

- Current and prospective market conditions are classified by higher interest rates and elevated inflation which is similar to the conditions identified by the Commission in its recent decisions for Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. ("Aqua"), Columbia Water Company ("Columbia Water") and Pennsylvania-American Water Company ("PAWC") as reasons for placing weight on the CAPM result in determining the ROE.[6]
    - Applying a 50/50 weighting to the adjusted and updated results of Mr. Keller's DCF and CAPM analyses results in an ROE estimate for Pike of 10.60 percent.
    - Similarly, relying on a 50/50 weighting of Ms. Reno's DCF and CAPM analyses and reasonable adjustments to those analyses, results in an ROE estimate for Pike of 10.34 percent.
- Ms. Reno incorrectly concludes that the Company has similar business risk as the companies included in her proxy group. However, while the Company would have similar regulatory risk as the proxy group if the Company's proposed Weather Normalization Adjustment Mechanism ("WNA") is approved, Ms. Reno has failed to consider the Company's small size risk in that Pike is substantially smaller than the companies included in her proxy group. Thus, when considering both regulatory and size risk, the Company has greater business risk relative to the proxy group.
- Ms. Reno's recommendation to set a "maximum" equity ratio at the Company's proposed equity ratio of 50.63 percent is unreasonable because:
    - an equity ratio of 50.63 percent is well below the average actual equity ratio of the utility subsidiaries of Ms. Reno's proxy group companies.
    - While I disagree with Ms. Reno that the Company's proposed capital structure should be compared to the average equity ratios of the proxy group holding companies, if that analysis is performed correctly, it also demonstrates that the Company's proposed equity ratio is well below the proxy group average equity ratios and therefore indicates greater financial risk relative to the proxy group.
    - an equity ratio of 50.63 percent is below the average authorized equity ratios for natural gas utilities from 2020-2024 and well below the maximum equity ratio authorized over this time-period.

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[6] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, at 154-155 (Order entered May 16, 2022); *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 107-108 (Order Entered January 18, 2024); and *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, at 171-172 (Order Entered July 22, 2024).

III. CAPITAL MARKET CONDITIONS AND A COMPARABLE RETURN

Q. Do you generally agree with Ms. Reno's characterizations of the changes in market conditions over the past few years?

A. Yes. I generally agree with Ms. Reno's characterization of the capital market conditions over the past few years. Ms. Reno recognizes that short-term and long-term interest rates are significantly higher than at the time of the Company's last rate proceeding due to the Federal Reserve's efforts to combat persistently high inflation.[7] Further, Ms. Reno acknowledges that investors expect inflation to remain elevated over the long-term term, which could cause the Federal Reserve to delay further cuts in the federal funds rate.[8] Finally, Ms. Reno notes that both the national and Pennsylvania economy continue to grow and remain strong.[9] According to Ms. Reno, investors will consider each of these factors in determining their cost of equity over the long-term.[10] However, while I generally agree with Ms. Reno's summary of the capital market conditions over the past few years, I disagree with her conclusion regarding the effect of those conditions on the cost of equity for the Company.

Q. What conclusion does Ms. Reno draw from the changes in market conditions?

A. Ms. Reno contends that the utility sector is a defensive sector or a "safe investment" because utilities are regulated and provide an essential service.[11] Therefore, during times of increased uncertainty demand for utility stocks will increase, resulting in a decrease in the cost of equity. Ms. Reno contends that uncertainty is currently high due to persistently

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[7] Reno Direct Testimony, at 13.

[8] *Id.,* at 16.

[9] *Id.,* at 17-18.

[10] *Id.,* at 12.

[11] *Id.,* at 19.

high inflation that has forced the Federal Reserve to delay interest rate cuts as well as the potential effect on the economy of the Trump Administration's tariffs.[12]

Q. Is Ms. Reno's conclusion regarding the effect of capital market conditions consistent with the market data that she has presented?

A. No. As noted above, Ms. Reno presented data that showed that inflation and interest rates remain elevated, and both the national and Pennsylvania economies have continued to grow. These indicators do not support the expectation of an economic downturn that would increase the demand for utility stocks. Specifically, Ms. Reno concludes the following regarding the relationship between interest rates, the economy and utility stocks:

> Total returns on utility stocks are dependent on investors' expectations of where interest rates will go next and prospects for the economy in general since investors choose these stocks (with low betas) over economically sensitive higher-risk stocks during an economic downturn.[13]

According to Ms. Reno, the demand for utility stocks would increase if interest rates and the prospects for the economy declined. However, Ms. Reno provided evidence demonstrating that economic decline is not expected:

> [h]owever, the flattening yield curve for February 28, 2025 shows that yields on longer-term bonds are increasing while yields on short-term T-Bills are falling slightly, which suggests that investors may not be expecting an economic slowdown.[14]

Ms. Reno also referenced the *Survey of Professional Forecasters* published by the Federal Reserve Bank of Philadelphia, which projected real GDP growth of approximately 2 percent over the near-term.[15] The evidence provided by Ms. Reno shows that investors

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12 *Id.*, 19-20

13 *Id.,* 19.

14 *Id.,* 16.

15 *Id.,* 17.

are not expecting a recession. Further, as I will show below, investors also expected long-term bond yields to remain elevated over the near and long-term. As a result, current market evidence would not support Ms. Reno's conclusion that the cost of equity for utilities is declining.

Q. Do changes in capital market conditions since the Company's last rate proceeding continue to indicate an increase in the cost of equity?

A. Yes. Changes in long-term bond yields since the Company's last rate proceeding demonstrate an increase in the cost of equity. Specifically, as shown in Figure 2, long-term bond yields have increased substantially since the Commission's decision to adopt the settlement in the Company's last rate proceeding. Further, while the federal funds rate was reduced by the Federal Reserve at the Federal Open Market Committee ("FOMC") meetings in September, November, and December 2024, the FOMC did not reduce the federal funds rate at the January and March 2025 FOMC meetings and continues to indicate an expectation that there may be only two rate reductions before the end of 2025.[16] Therefore, the federal funds rate is also expected to remain well above the levels seen at the time of the Company's last rate case. Finally, while inflation has declined, it remains above the Federal Reserve's target of 2 percent.

[16] Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

Figure 2: Changes in Capital Market Conditions Since Pike's Last Rate Proceeding[17]

Period	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate
Docket No. R-2020-3022134	6/17/2021	0.10%	2.28%	4.42%
Current	3/31/2025	4.33%	4.61%	2.81%
Change		4.23%	2.33%	-1.61%

Q. What is the expected path of monetary policy over the near-term?

A. At the March 2025 FOMC meeting, Chairman Powell noted that labor market conditions are "solid" and while inflation has declined it still remains above the Federal Reserve's target of 2 percent, as a result, the FOMC decided to maintain the current federal fund rate range of 4.25 percent to 4.50 percent.[18] Regarding the possible path of monetary policy, Chairman Powell continued to reiterate that policy is "not on any preset course"; but, he acknowledged increased uncertainly due to the implementation of significant policy changes (*i.e.,* trade, immigration, fiscal policy and regulation) by the Trump Administration.[19] Chairman Powell noted that the FOMC will continue to analyze incoming data to determine the effect of such policy changes and was in a good position to adjust the course of monetary policy if needed.[20] Thus, the FOMC's forecast of the federal funds rate remained unchanged from the December 2024 meeting, forecasting just two rate cuts before the end of 2025.[21]

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17 St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

18 Transcript of Chairman Powell's Press Conference (March 19, 2025).

19 *Id.*

20 *Id.*

21 Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

More recently, during an event at the Economic Club in Chicago, Chairman Powell acknowledged that the recent tariff policy of the Trump Administration has caused volatility and uncertainty in the market, but that policy was currently well positioned and that the Federal Reserve could rely on incoming economic data to gain greater clarity on the economic effects of the tariffs before considering changes to policy.[22] Further, in regard to economic conditions, Chairman Powell reiterated that the labor market was "in solid condition" but he did acknowledge that tariffs would cause temporary inflation that could be more persistent depending on how long it takes the tariffs to fully flow through to prices which the Federal Reserve is monitoring.[23]

Q. What has happened to the yields on long-term government bonds since the FOMC reduced the federal funds rate in September 2024?

A. As shown in Figure 3 below, while the yield on the 30-year treasury bond declined prior to the time of the first federal funds rate cut, the yield has increased since the September 2024 FOMC meeting. As of April 11, 2025, the 30-year Treasury bond yield was 4.85 percent, which is consistent with levels seen in February 2024, over six months prior to the reductions in the federal funds rate.

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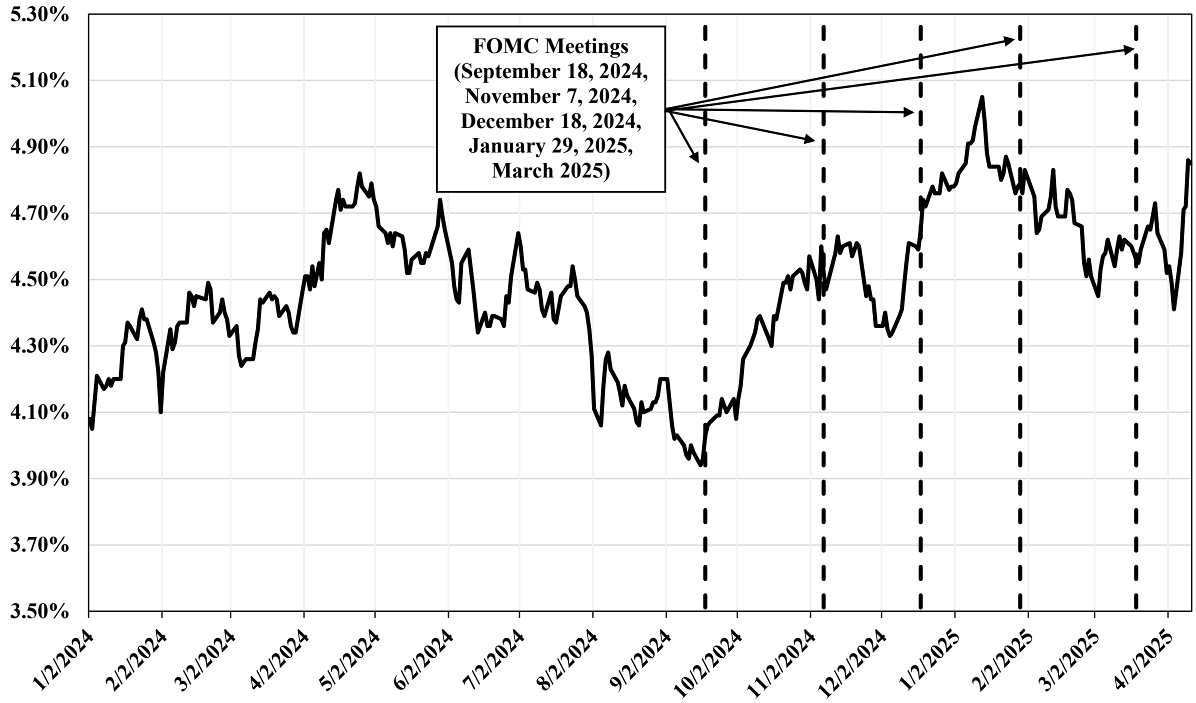
[22] Howard Schneider and Ann Saphir, "Powell says Fed remains in wait-and-see mode; markets processing policy shifts," Reuters (April 16, 2025).

[23] *Id.*

Figure 3: 30-Year Treasury Bond Yield, January 1, 2024 – April 11, 2025[24]



Q. Why have long-term interest rates increased since the Federal Reserve reduced the federal funds rate in September?

A. Investors view key elements of President Trump's economic plan, such as tax cuts, immigration policy, and tariffs, as inflationary. According to a recent *Reuters* article, the increase in long-term government bond yields was initially related to investors responding to an increasing probability of a Trump Administration in 2025 and has continued since President Trump's re-election and inauguration.[25] For example, on April 2, 2025, President Trump announced a significant set of tariffs on each of the U.S.'s trading partners, a policy initiative that is largely viewed as inflationary. Inflation affects bonds, in particular long-term government bonds, because it erodes the value of future bonds

[24] S&P Capital IQ Pro.

[25] Davide Barbuscia and Lewis Krauskopf, "Bond rebound uncertain as Trump plans overshadow Fed rate cuts," Reuters (November 8, 2024).

payments. Therefore, in an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation thus bond prices decline and the yields on bonds increase. The longer the duration of the bond, the greater the effect of inflation which is why inflation risk is greater for long-term government bonds. The significant tariff policy increases the risk that inflation will remain elevated which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve reduced the federal funds rate. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields.[26]

Q. What are expectations for the yields on long-term government bonds?

A. Economists and analysts are expecting elevated rates. *Blue Chip Financial Forecasts* provides a forecast from economists on the 30-year Treasury bond. In the most recent published *Blue Chip Financial Forecasts* report, economists projected the 30-year treasury rate to remain relatively stable and decrease only slightly from 4.60 percent in Q2/2025 to 4.50 percent in Q2/2026.[27] Additionally, the consensus estimate over the longer-term (i.e., 2026-2030) as published in the December 2024 *Blue Chip Financial Forecasts* report was 4.30 percent.[28] This is important because it means that long-term interest rates: (1) are expected to remain elevated during the period that the Company's rates will be in effect;

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26 Vanjani, Karishma, "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," Barron's (April 9, 2025).

27 *Blue Chip Financial Forecasts*, Vol. 44, No. 4, April 1, 2025, at 2.

28 *Blue Chip Financial Forecasts*, Vol. 43, No. 12, November 27, 2024, at 14.

and (2) will remain at levels well above the levels at the time of the Company's last rate proceeding.

Q. Are authorized returns in other jurisdictions a relevant benchmark to evaluate the reasonableness of Ms. Reno's ROE recommendation?

A. Yes, they can be when the corresponding market conditions are considered. The *Hope* and *Bluefield* cases establish that authorized ROEs must be commensurate with other investments having corresponding risk. Therefore, the regulatory decisions of other utility regulatory commissions provide a range of reasonableness and a benchmark that investors consider in assessing the authorized ROE of one utility against the returns available from other regulated utilities with comparable risk.

Q. Do either Mr. Keller or Ms. Reno agree that it is appropriate to consider previously authorized ROEs?

A. Yes. Mr. Keller references an average authorized return for natural gas utilities in 2024 of 9.72 percent[29] while Ms. Reno appears to benchmark her recommended ROE of 9.30 percent to the average authorized return for natural gas utilities of 9.71 percent in 2024 and 9.60 percent in 2023.[30]

Q. Do you have any concerns with the review of authorized returns conducted by Mr. Keller and Ms. Reno?

A. Yes. I have several concerns with the review of authorized returns conducted by both Mr. Keller and Ms. Reno:

- Mr. Keller incorrectly includes limited-issue rider cases which only address a specific issue or issues and do not consider the entire operations of a utility.

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[29] Keller Direct Testimony, at 34.

[30] Reno Direct Testimony, at 55.

- Both Mr. Keller and Ms. Reno fail to consider the ratemaking environment to determine whether the ROE that was authorized was determined on the same basis as the Commission makes its decisions in rate proceedings.

- Neither Mr. Keller nor Ms. Reno have not considered the effect of market conditions particularly the differences in the market conditions that existed when the returns were authorized relative to current market conditions. As Ms. Reno has acknowledged, interest rates have increased substantially over the past few years and are expected to remain elevated over the near-term.

- Both Mr. Keller and Ms. Reno rely on the annual average authorized returns instead of also considering the full range of authorized returns. However, it is important to consider the range of authorized returns due to the recent change in market conditions discussed, as well as to consider the business risk of the Company.

Q. Have you reviewed recently authorized ROEs for utilities?

A. Yes. I have analyzed the recently authorized returns for natural gas utilities and applied the following screening criteria:

- I excluded limited-issue rider cases because these cases address only a specific issue or issues, such as the construction of generation assets and the associated incremental risk, and not a utility's entire operations.

- I excluded jurisdictions that set ROEs using a formula as opposed to following an approach that is similar to what the Commission has typically considered in setting the ROE.

- I excluded returns awarded in Arizona, because the determinations in Arizona are based on fair value ratemaking adjustments. Therefore, the ROE that was established in the Arizona cases may have been set on a different basis.

- Lastly, I excluded authorized returns that reflect a utility-specific penalty, because an authorized ROE that includes a penalty is not indicative of a market-derived cost of equity.

As shown in Figure 4, since 2020, authorized ROEs for natural gas utilities and interest rates have increased. Further, both Mr. Keller's recommended ROE of 9.66 and Ms. Reno's recommended ROE of 9.30 percent are below the average authorized ROE for natural gas utilities in the U.S. in 2024 with Ms. Reno's recommended ROE of 9.30 percent at the very low-end of the range returns authorized for natural gas utilities in 2024. Finally, the Company's requested ROE of 10.20 percent is within the range of authorized returns for natural gas utilities in 2024.

Figure 4: Range of Annual Authorized ROE for Natural Gas Utilities, 2020-2024[31]

Year	Average	Min.	Max.	30-Year Treasury Bond Yield
2020	9.48%	8.80%	10.00%	1.56%
2021	9.56%	8.80%	10.24%	2.05%
2022	9.53%	9.00%	10.20%	3.12%
2023	9.58%	9.20%	10.25%	4.09%
2024	9.73%	9.30%	11.88%	4.41%

Q. Are either Mr. Keller's or Ms. Reno's ROE recommendation for the Company in this proceeding reasonable based on a comparison to recent authorized returns for natural gas utilities?

A. No. Both Mr. Keller's ROE recommendation of 9.66 percent and Ms. Reno's ROE recommendation of 9.30 percent are inconsistent with the trend of increasing interest rates and increasing authorized ROEs, which is also supported by the data provided in Ms. Reno's direct testimony. Further, neither witness has provided any evidence to demonstrate that the Company's ROE should be below the mean authorized ROE in 2024. It is therefore unreasonable to conclude that either Mr. Keller's ROE recommendation or Ms. Reno's ROE recommendation would reflect the investor-required return on equity for a natural gas utility in current market conditions.

[31] S&P Capital IQ Pro.

IV. RESPONSE TO MR. KELLER

Q. Please summarize your concerns with Mr. Keller's ROE analyses.

A. Specifically, I have the following concerns with the cost of equity analyses conducted by Mr. Keller:

- the composition of Mr. Keller's proxy group;
- Mr. Keller's sole reliance on the results of his constant growth DCF model to determine his recommended ROE; and
- the risk-free rate and market risk premia that Mr. Keller relies on to calculate his CAPM analysis.

A. <u>Proxy Group</u>

Q. How did Mr. Keller select the companies included in his proxy group?

A. Mr. Keller relies on a proxy group that is based on a group of U.S. utilities that the *Value Line* classifies as natural gas utilities, to which he then applies the following set of screening criteria: (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; and (6) the company must be operating in a state that has a deregulated gas utility market.[32] The screening criteria resulted in a proxy group consisting of 7 natural gas utilities.

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[32] Keller Direct Testimony, at 8-9.

Q. Do you have any concerns with the screening criteria relied upon by Mr. Keller.

A. Yes, I disagree with Mr. Keller's screen that ensures the companies included in the proxy group derive a certain portion of their operations from regulated natural gas distribution operations for two reasons. First, Mr. Keller's screen relies on revenue instead of operating income. However, operating income is the more appropriate screening criterion because it better reflects the contribution of each business segment to the corporation's earnings. For regulated utilities that collect the cost of purchased gas, fuel, and/or power on a pass-through basis through rates, regulated revenue can fluctuate materially with changes in weather without affecting the corporation's earnings or financial position. In contrast, operating income, which excludes purchased commodity costs, more closely represents the effect of each business segment on the corporation's overall risk profile.

Second, Mr. Keller requires that a company derive at least 50 percent of revenues from regulated natural gas distribution operations; however, the required percentage should be greater than 50 percent because Mr. Keller's screen could result in a company being included in the proxy group that derives 50 percent of total revenue from unregulated operations. It is unreasonable to conclude that a company that derives 50 percent of total revenue from unregulated operations would be considered comparable to a company that derives 100 percent of revenue from regulated natural gas distribution operations such as Pike.

Q. Would the composition of Mr. Keller's proxy group change had he relied on an operating income screen as opposed to a revenue screen?

A. Yes. If Mr. Keller correctly relied on an operating income screen as opposed to a revenue screen, I believe he would have excluded Chesapeake Utilities ("Chesapeake") and New

Jersey Resources ("NJR") from his proxy group and included Southwest Gas Holdings, Inc ("SWX") in his proxy group.[33] For example, as shown in Exhibit CMR-2R, Chesapeake derived only 39.52 percent of its total operating income from regulated natural gas distribution operations for the three-year period of 2022-2024 which is even substantially less than the 50 percent level that Mr. Keller required for inclusion in his proxy group when applying his revenue screen.

Similarly, as shown in Exhibit CMR-2R, NJR derived only 50.02 percent of its total operating income from regulated natural gas distribution operations for the three-year period of 2022-2024. While NJR would meet an operating income screen that similar to Mr. Keller's screen required a company to have greater than 50 percent of total operating income derived from natural gas operations; as also shown in Exhibit CMR-2R, NJR derives only 56.48 percent of total operating income from regulated operations for the three-year period of 2022-2024. Therefore, NJR has significant unregulated operations and should have been excluded from Mr. Keller's proxy group.

Finally, as shown in Exhibit CMR-2R, SWX derived 85.23 percent of total operating income from regulated natural gas distribution operation in 2024.[34] Furthermore, it is important to note that the percentage of operating income from natural gas operations is likely to increase going forward as SWX spun-off its unregulated utility infrastructure construction business, Centuri Group, Inc. ("Centuri") in April 2024.[35] As a result, had

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33 Mr. Keller has not provided his proxy group screening workpaper; however, because SWX derived less than 50 percent of revenue from natural gas distribution operations in 2024, I assumed Mr. Keller excluded SWX because the company did not meet his revenue screen.

34 2024 was considered as opposed to the three-year period of 2022-2024 because SWX divested its pipeline and storage segment in 2023. Therefore, reliance on data prior 2024 would not be representative of SWX's operations moving forward. See SWX, 2024 Form 10-K, at 63.

35 Manya Saini and David French, "Southwest Gas unit jumps in strong market debut," Reuters, April 18, 2024.

Mr. Keller relied on operating income, he would have concluded that SWX derives a substantial portion of its operating income from regulated natural gas distribution operations and should have been included in his proxy group.

Q. Have you adjusted Mr. Keller's proxy group?

A. Yes, I have. First, while I disagree with Mr. Keller's inclusion of NJR and Chesapeake in his proxy group, to limit the disagreements between myself and Mr. Keller, I have not adjusted his proxy group to exclude either NJR or Chesapeake. However, given that SWX derives a greater percentage of operating income from regulated natural gas operations than either Chesapeake or NJR, I believe that Mr. Keller should have included SWX in his proxy group. Further, SWX was included in Ms. Reno's proxy group as well as in the proxy group relied on by the Commission's Bureau of Technical Utility Services ("TUS") to estimate the return on equity for the Distribution System Improvement Charge ("DSIC") for gas utilities in the June 2024 report. By relying on a revenue screen as opposed to an operating income screen, Mr. Keller incorrectly excluded SWX, a company that investors would consider comparable to Pike.

B. <u>Constant Growth DCF</u>

Q. Please summarize the constant growth DCF analysis prepared by Mr. Keller?

A. Mr. Keller prepared a constant growth DCF using the proxy group discussed previously, which consisted of 7 natural gas distribution companies. He relied on historical average and spot stock prices as of January 23, 2025, projected dividends for 2025 and analysts' earnings per share ("EPS") growth rates. The mean result of Mr. Keller's constant growth DCF analysis is 9.66 percent.[36]

Q. What are your primary concerns with Mr. Keller's constant growth DCF model?

A. I have two concerns with Mr. Keller's constant growth DCF analysis: (1) Mr. Keller has incorrectly excluded SWX from the proxy group he has relied on to calculate his constant growth DCF analysis; and (2) Mr. Keller's sole reliance on the result of his constant growth DCF analysis to determine his ROE recommendation for Pike.

Q. How would Mr. Keller's constant growth DCF result change if he had included SWX in his proxy group?

A. As shown in Exhibit CMW-3R, the mean result of his constant growth DCF analysis would increase from 9.66 percent to 10.02 percent.

Q. Do you agree with Mr. Keller's sole reliance on his constant growth DCF result to determine his recommended ROE?

A. No. In fact, Mr. Keller's decision to rely solely on the constant growth DCF model to determine the authorized return for Pike is inconsistent with the methodology relied on to determine the ROE in the Commission's recent decisions for Aqua,[37] Columbia Water[38] and PAWC[39]. The Commission was clear in its decisions in rate cases for Aqua, Columbia Water, and PAWC that it was not accepting I&E's position to rely exclusively on the DCF results. In its decision for Aqua, the Commission noted that inflation was currently high

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[36] Keller Direct Testimony, at 25-26.

[37] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, at 154-155 (Order entered May 16, 2022).

[38] *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 107-108 (Order Entered January 18, 2024).

[39] *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, at 171-172 (Order Entered July 22, 2024).

and that the Federal Reserve was ending its accommodative monetary policy to keep interest rates low in response to inflation. Further, the Commission noted that the DCF model is slow to respond to changes in interest rates while the CAPM can be calculated using forecasted interest rates and thus captures "forward-looking" changes in interest rates.[40] As a result, the Commission concluded that it would determine Aqua's authorized ROE based on both the DCF and CAPM models as opposed to relying solely on the DCF model as proposed by Mr. Keller. This was consistent with the Commission's long-standing openness to consideration of other ROE models when appropriate:

> As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[41]

The Commission relied on the range of results of 8.90 percent to 9.89 percent produced by I&E's DCF and CAPM models, and ultimately authorized an ROE of 9.75 percent at the high end of the range considering increased inflation leading to increases in interest rates and capital costs since Aqua filed its rate case.[42]

Likewise in its decision for Columbia Water, the Commission affirmed its view that the DCF and the CAPM should be relied upon to set the range, agreeing with the Administrative Law Judge that the CAPM is more responsive to changes in interest rates. Further, the Commission recognized that where evidence based on other methodologies

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[40] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, at 154 (Order entered May 16, 2022).

[41] *Id.,* at 155.

[42] *Id.*, at 178. The Commission authorized an ROE for Aqua of 10.00 percent which was based on a 9.75 percent ROE considering the DCF and CAPM results plus a 0.25 percent adder for management performance.

suggests that the DCF results may understate the utility's ROE, the Commission will consider those methods to some degree in determining the appropriate range of reasonableness. As such, the Commission established its range based on the DCF and CAPM results and used its judgment as to where within that range to set the ROE, which was 9.75 percent.[43]

Finally, in its decision for PAWC, the Commission agreed with the Administrative Law Judge and continued to affirm its view that the CAPM results in addition to the DCF results should be relied upon to determine the ROE for PAWC. For PAWC, the Commission authorized an ROE of 9.45 percent based on an average of the DCF and CAPM results.[44]

Q. Do you agree with Mr. Keller that current market conditions are not consistent with those that resulted in the Commission utilizing both the DCF and CAPM results in the determination of the ROE in the recent decisions for Aqua, Columbia Water and PAWC?

A. No, I do not. Mr. Keller contends inflation is expected to be in the range of 2 percent to 3 percent for 2025 to 2026, which is much lower than the levels in prior years thus reducing the effect of interest rate and inflation risk on the cost of equity during the period that Pike's rates will be in effect.[45] However, Mr. Keller's conclusion is incorrect for several reasons. First, Mr. Keller references inflation forecasts from the *Blue Chip Financial Forecasts*

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43 *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 107-108 (Order Entered January 18, 2024).

44 *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, at 190 (Order Entered July 22, 2024). The Commission authorized an ROE for PAWC of 9.55 percent which was based on a 9.45 percent ROE considering the DCF and CAPM results plus a 0.10 percent adder for management performance.

45 Keller Direct Testimony, at 22.

report in December 2024, which would not consider the effect of the recent tariff policy enacted by the Trump Administration. As noted in Section III above, Chairman Powell stated in a recent speech that tariffs will likely increase inflation temporarily, and the effect could be more persistent depending on how long it takes the tariffs to fully flow through to prices. Second, the inflation forecasts referenced by Mr. Keller still show inflation remaining above the Federal Reserve's target of 2 percent through Q2/2026 before the effect of tariffs is considered. Given that inflation will likely remain above the Federal Reserve's target of 2 percent over the near-term, long-term interest rates are expected to remain elevated. Therefore, it is reasonable to conclude that current market conditions are consistent with those that resulted in the Commission relying on the results of the DCF and CAPM in the recent proceedings for Aqua, Columbia Water, and PAWC. As a result, consistent with the Commission's recent decisions, Mr. Keller should have relied on both his constant growth DCF and CAPM results for purposes of developing his recommended ROE, and by failing to do so, has understated the cost of equity for Pike.

Q. Have you updated Mr. Keller's constant growth DCF analysis to reflect more recent market data?

A. Yes. Given the recent changes in market conditions just discussed and referenced in Section III above, I updated Mr. Keller's constant growth DCF analysis to reflect market data (*i.e.,* share prices, dividends, and growth rates) through March 31, 2025. As shown in Exhibit CMW-3R, when Mr. Keller's analysis is updated with current data and SWX is included in his proxy group, the mean cost of equity result is 10.49 percent.[46] The updated

[46] While I believe SWX should be included in the proxy group, as shown in Exhibit CMW-3R, if SWX is excluded and Mr. Keller's analysis is updated to reflect current data, his mean constant growth DCF increases from 9.66 percent to 10.10 percent.

constant growth DCF results provides support for my conclusion that the Company's requested ROE of 10.20 percent is reasonable.

C. CAPM Analysis

Q. Please summarize Mr. Keller's CAPM analyses.

A. Mr. Keller conducts two forms of the CAPM analysis. Mr. Keller's first CAPM reflects a risk-free rate that is the projected yield on the 10-year Treasury bond of 4.23 percent, betas for his proxy group as reported by *Value Line*, and a market risk premium based on the average of (i) an estimate of the total return for the companies in the *Value Line* universe, and (ii) the historical average return on the S&P 500. Mr. Keller's second CAPM reflects the same betas as in his first CAPM scenario, but a spot yield on the 20-year Treasury bond yield as the estimate of the risk-free rate and a projected market risk premium published by *Kroll.* The results of Mr. Keller's CAPM analyses range from 9.05 percent to 11.28 percent with an average of 10.16 percent.[47] Ms. Keller states that he relies on the CAPM as only a comparison to his DCF results, he does not either rely on the CAPM to set his ROE recommendation nor does he rely on it as a check on the results of the DCF.[48]

Q. Do you have any concerns with the CAPM analyses conducted by Mr. Keller:

A. Yes. I have the following concerns with Mr. Keller's CAPM analyses:

- Incorrectly excluded SWX from the proxy group he has relied on to calculate his CAPM analysis.
- Relies on the projected yield on the 10-year Treasury bond as opposed to the projected yield on the 30-year Treasury Bond. While I recognize the Commission's previous decision to use the 10-year Treasury bond as the risk-free rate in the CAPM analysis, in determining the security most relevant to the application of the CAPM, as Morningstar notes, it is important to select the term (or maturity) that

[47] Keller Direct Testimony, at 29-31.

[48] *Id.,* at 16.

best matches the life of the underlying investment.[49] Because utility companies represent long-duration investments, the 30-year Treasury bond yield, not the 10-year Treasury bond yield, is the appropriate measure of the risk-free rate for the purpose of the CAPM. In addition, based on principles of prudent financial management, the term of the debt financing should match the useful life of the assets being financed. Utility plant assets generally have useful lives between 25 and 40 years, meaning that, under prudent financial management, those assets should be financed with bonds of longer duration than 10 years.

- Relies on a *Value Line* report for a single week – January 24, 2025 – in the development of his projected market return. As shown in Exhibit CMW-4R, the *Value Line* Appreciation Potential was somewhat variable over the last few months resulting a market return range from 10.78 percent to 17.52 percent from January 3, 2025, through May 2, 2025. Thus, relying on a *Value Line* report for a single week could result in significant variations in the market return and thus CAPM results from week-to-week.

- Relies on *Kroll's* recommended market risk premium of 5.00 percent, which as I will discuss in more detail in my response to Ms. Reno does not reflect the inverse relationship between interest rates and the market risk premium (*i.e.,* as interest rates increase, the market risk premium decreases and vice versa). For example, given that current yields on Treasury bonds are lower than yields historically, it is reasonable to conclude that the market risk premium should be greater than the long-term average. However, *Kroll's* market risk premium of 5.00 percent is well below the long-term average historical market risk premium from 1926 through 2024 of 7.31 percent[50] and therefore does not reflect the inverse relationship between the market risk premium and interest rates. Further, Mr. Keller's CAPM analysis that relies on *Kroll's* recommended market risk premium results in a cost of equity of 9.05 percent. An ROE of 9.05 percent is well below the average annual authorized ROEs for natural gas utilities from 2020 to 2024, which includes returns authorized in a much lower interest rate environment. Therefore, Mr. Keller's CAPM analysis that relies on *Kroll's* recommended market risk premium does not produce a result that reflects the investor-required return on equity for a natural gas utility in current market conditions.

[49] Morningstar, Inc., 2010 Ibbotson Stocks, Bonds, Bills and Inflation, Valuation Yearbook, at 44.

[50] *Kroll* Cost of Capital Navigator.

Q. Have you adjusted Mr. Keller's CAPM analysis to correct for some of the issues you have identified?

A. Yes. Specifically, I adjusted Mr. Keller's CAPM analysis to: (1) include SWX in his proxy group; and (2) reflect market data through March 31, 2025[51]. As shown in Figure 5 (see also Exhibit CMW-6R), applying these reasonable updates and adjustments to Mr. Keller's CAPM analyses results in a cost of equity range of 9.18 percent to 12.26 percent with an average of 10.72 percent.[52]

Figure 5: Summary of Adjustments to Mr. Keller's CAPM Analysis

	As Filed	Incl. SWX	Updated & Incl. SWX
Value Line and S&P 500 Market Return	11.28%	11.33%	12.26%
Kroll Recommended MRP	9.05%	9.08%	9.18%
Average of CAPM Results	**10.16%**	**10.20%**	**10.72%**

D. Adjustments to Mr. Keller's Cost of Equity Analyses

Q. Please summarize the results of Mr. Keller's cost of equity estimation models based on your suggested adjustments to his models.

A. Figure 6 (see also Exhibit CMW-3R and Exhibit CMW-6R) presents the results of Mr. Keller's analyses when they are updated to use the most current data available and corrected to rely on a proxy group that includes SWX. As shown in Figure 6, Mr. Keller's

[51] I relied on market data through March 31, 2025 to update Mr. Keller's CAPM analyses; however, on April 15, 2025, *Kroll* increased its recommended market risk premium from 5.00 percent to 5.50 percent. Therefore, the adjusted CAPM results are likely conservative given the recent change in *Kroll's* recommended market risk premium.

[52] While I also do not agree with the use of either the 10-year Treasury bond as the estimate of the risk-free rate, *Kroll's* recommended market risk premium or the *Value Line* report in a single week to develop the market return in the CAPM for the reasons discussed, applying the adjustments discussed results in CAPM results that support the Company's requested ROE of 10.20 percent. As a result, I have limited my response and did not calculate a version of the CAPM that adjusts for each of my concerns with the inputs to the CAPM relied on by Mr. Keller.

constant growth DCF result increases from 9.66 percent to 10.49 percent and his average CAPM result increases from 10.16 percent to 10.72 percent. Further, considering the Commission's decisions in the recent rate proceedings for Aqua, Columbia Water, and PAWC where the Commission placed weight on the results of the CAPM in determining the ROE, simply placing equal weight on the adjusted results of Mr. Keller's DCF and CAPM analysis would result in a cost of equity of 10.60 percent, which is greater than the Company's ROE request of 10.20 percent in this proceeding.

Figure 6: Adjusted Results of Mr. Keller's Cost of Equity Estimation Models

	As Filed	Incl. SWX	Updated & Incl. SWX
Constant Growth DCF	9.66%	10.02%	10.49%
CAPM	10.16%	10.20%	10.72%
Average of DCF and CAPM	**9.91%**	**10.11%**	**10.60%**

V. RESPONSE TO MS. RENO

Q. Please summarize your concerns with Ms. Reno's ROE analyses.

A. Specifically, I have the following concerns with the cost of equity analyses conducted by Ms. Reno:

- the composition of Ms. Reno's proxy group;
- Ms. Reno's reliance on projected dividend per share ("DPS"), projected book value per share ("BVPS"), and sustainable growth rates in her constant growth DCF model;
- Ms. Reno's sole reliance on the results of her constant growth DCF model to determine her recommended ROE;
- the market risk premia that Ms. Reno relies on to calculate her CAPM analysis;
- Ms. Reno's conclusions regarding the Company's business and financial risk relative to her proxy group; and

- Ms. Reno's conclusion that the Company's proposed equity ratio should be viewed as the maximum equity ratio allowed by the Commission.

A. Proxy Group

Q. How did Ms. Reno select the companies included in her proxy group?

A. Ms. Reno relies on a proxy group that is based on a group of U.S. utilities that the *Value Line* classifies as natural gas utilities, to which she then applies the following set of screening criteria: (1) not involved in a transformative transaction; (2) consistently pay a dividend that has not been cut in the last six months; (3) covered by at least two utility equity analysts; and (4) have an investment grade credit rating.[53] The screening criteria resulted in a proxy group consisting of 8 natural gas utilities that Ms. Reno notes is the same proxy group relied on by the Commission's Bureau of TUS to estimate the return on equity for the DSIC for gas utilities in the June 2024 report.[54]

Q. Are the screening criteria applied by Ms. Reno appropriate for establishing a proxy group of companies that are most comparable to Pike?

A. No. In fact, I disagree with both the selected screens as well as Ms. Reno's incorrect application of her selected screens which results in the incorrect inclusion of Chesapeake and NJR in her proxy group. For example, Ms. Reno contends that she required companies have an investment grade credit rating for inclusion in her group; however, Chesapeake does not currently have a credit rating from either S&P or Moody's and therefore would not meet Ms. Reno's investment grade credit rating screen. Since Chesapeake does not meet Ms. Reno's investment grade credit rating screen it is unclear how she determined Chesapeake should be included in the proxy group.

[53] Reno Direct Testimony, at 29.

[54] *Id.*

Additionally, Ms. Reno does not apply a screening criterion to determine the portion of unregulated operations for each of the natural gas utilities considered for inclusion in the proxy group. However, each of the companies included in the proxy group should derive a substantial portion of their operating income from regulated distribution operations similar to Pike. As shown in Exhibit CMR-2R, NJR derives less than 70 percent of operating income from regulated operations and therefore should have been excluded from Ms. Reno's proxy group.

However, while I believe that Ms. Reno's proxy group is less comparable to Pike for the reasons discussed above, the concerns I have with Ms. Reno's proxy group do not currently result in a significant change to the results the cost of equity models. As a result, I will not further discuss my disagreements with her proxy group.

B. <u>Constant Growth DCF Analysis</u>

Q. Please summarize Ms. Reno's constant growth DCF analyses.

A. Ms. Reno conducts three constant growth DCF analyses, the first version relies on projected EPS growth rates from *S&P Capital IQ Pro*, *Zacks* and *Value Line*, the second relies on projected EPS growth rates from *S&P Capital IQ Pro*, *Zacks* and *Value Line*, and projected BVPS, and DPS growth rates from *Value Line*, and the third relies on estimated sustainable growth rates. Ms. Reno calculates dividend yields using average stock prices over 30- and 90-days for the period ending February 28, 2025. The results of Ms. Reno's constant growth DCF analysis range from 8.71 percent to 9.84 percent, with a midpoint of 9.27 percent.[55]

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[55] Reno Direct Testimony, at 47.

1. <u>Selection of the Growth Rate in the Constant Growth DCF model</u>

Q. What is your primary area of disagreement with the growth rates that Ms. Reno has relied on to estimate her constant growth DCF analyses?

A. While I agree with Ms. Reno's reliance on projected EPS growth rates to calculate the first version of her constant growth DCF analysis, I disagree with Ms. Reno's reliance on projected DPS and BVPS growth rates as well as sustainable growth rates to calculate the second and third versions of her constant growth DCF analysis.

Q. As a threshold matter, are the results of Ms. Reno's constant growth DCF scenarios that rely on projected DPS and BVPS growth rates and sustainable growth rates reasonable?

A. No. The results of Ms. Reno's constant growth DCF scenario using projected EPS, BVPS, and DPS growth rates range from 8.83 percent to 8.85 percent. The results of Ms. Reno's constant growth DCF scenario using sustainable growth rates range from 8.71 percent to 8.74 percent.[56] The results of both of these scenarios are at the low-end of any authorized ROE for a natural gas utility in a regulatory jurisdiction comparable to Pennsylvania since at least 1980.

Q. Why do you disagree with Ms. Reno's use of projected DPS and BVPS growth rates?

A. There are several reasons why reliance on *Value Line* projections of DPS growth and BVPS growth are not appropriate:

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[56] Reno Direct Testimony, at 47.

- Earnings are the fundamental determinant of a company's ability to pay dividends, and over the long-term dividend growth can only be sustained by earnings growth.[57]

- Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can influence dividend growth rates in near-term periods. These decisions affect the dividends and the payout ratio in the short term but are not necessarily indicative of a firm's long-term earnings growth. For example, forty S&P 500 companies suspended dividend payments in 2020 as a result of the increased uncertainty due to COVID-19.[58] These dividend suspensions occurred because companies believed earnings over the short term would decline and, therefore, elected to conserve cash to offset the financial effects of COVID-19.

- Given that BVPS is the inverse of DPS, estimates of BVPS growth are also highly influenced by dividend policy. All else equal, investing earnings in assets increases BVPS, while paying dividends and not investing in assets decreases BVPS.

- There is significant academic research demonstrating that EPS growth rates are most relevant in stock price valuation.[59] For example, Liu, *et. al.* (2002) examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed. Gleason, *et. al*. (2012) found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts. The use of DPS growth rates ignores the academic research demonstrating that EPS growth rates are most relevant in stock price valuation.

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57 As noted by Brigham and Houston: "Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE). Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, at 317 (Concise Fourth Edition, Thomson South-Western, 2004).

58 Langley, Karen. "U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade." Wall Street Journal, July 8, 2020.

59 *See, e.g.*, Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66; Vander Weide, James H. and Willard T. Carleton. "Investor growth expectations: Analysts vs. history." *The Journal of Portfolio Management*, Spring, 1988; Harris, Robert S. and Felicia C.Marston. "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts." *Financial Management*, Summer, 1992; Advanced Research Center. "Investor Growth Expectations." Summer 2004; Brigham, Eugene F. and Dilip K. Shome and Steve R. Vinson. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." *Financial Management*, Vol. 14, No. 1, Spring, 1985; Morin, Dr. Roger A. New Regulatory Finance. Public Utilities Reports, Inc., 2006, pp. 299-303; Liu, Jing, *et al*. "Equity Valuation Using Multiples." *Journal of Accounting Research*, Vol. 40 No. 1, March 2002; Gleason, C.A., *et al*. "Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts." *Contemporary Accounting Research*, September 2011; Jung, Boochun, *et. al*. "Do financial analysts' long-term growth forecasts matter? Evidence from stock recommendations and career outcomes." *Journal of Accounting and Economics*, Vol. 53 Issues 1-2, February-April 2012.

- Investment analysts report predominant reliance on EPS growth projections. In a survey completed by 297 members of the Association for Investment Management and Research, the majority of respondents ranked earnings as the most important variable in valuing a security (more important than cash flow, dividends, or book value).[60]

- Ms. Reno relies on projected DPS and BVPS growth rates from *Value Line*, which are the views of an individual analyst. In contrast, projected EPS growth rates from *S&P Capital IQ Pro* and *Zacks* are based on consensus estimates available from multiple sources. In other words, projected EPS growth rates include the contributions of more than one analyst and thus the results are less likely to be biased in one direction or another. Moreover, the fact that projected EPS growth estimates are available from multiple sources on a consensus basis attests to the importance of projected EPS growth rates to investors when developing long-term growth expectations.

For all these reasons, projected EPS growth rates, not projected DPS or BVPS growth rates, should be used for purposes of estimating the cost of equity using the constant growth DCF analysis.

Q. Does Ms. Reno's reliance on projected DPS and BVPS growth rates from *Value Line* fail to satisfy one of the required assumptions to estimate the constant growth DCF model?

A. Yes. One of the primary assumptions of the constant growth DCF model is that the growth rate needs to be constant. Further, since earnings are the fundamental determinant of a company's ability to pay dividends, over the long-term, dividend growth can only be sustained by earnings growth. From this fact, it can be reasonably concluded that: (1) since DPS growth is sustained by EPS growth, DPS growth cannot exceed the growth in EPS over the long-term; and (2) while DPS growth can grow at a lower rate than EPS if a company is retaining a larger portion of earnings, eventually DPS growth will increase in

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60 Block, Stanley B. "A Study of Financial Analysts: Practice and Theory." *Financial Analysts Journal*, July/August 1999.

the future if EPS and DPS are expected to growth at a constant rate.[61] Additionally, if either condition were to exist, then the projected DPS growth rate would be expected to change and thus could not be assumed in perpetuity as required by the constant growth DCF model.

Q. Have you considered whether *Value Line*'s projected DPS and EPS growth rates are equivalent?

A. Yes. As shown in Figure 7, *Value Line* only projects DPS growth to be equivalent to EPS growth for 1 of the 8 companies included in Ms. Reno's proxy group. Projected DPS growth for the remaining companies is either less than or greater than projected EPS growth. As a result, it would not be reasonable to assume *Value Line's* projected DPS growth rate in perpetuity for these companies.

Figure 7: *Value Line's* Projected EPS and DPS Growth Rates for Ms. Reno's Proxy Group[62]

	Value Line Projected		Difference
	EPS	**DPS**	**(EPS - DPS)**
Atmos Energy Corporation	6.00%	7.00%	-1.00%
Chesapeake Utilities Corporation	5.00%	7.50%	-2.50%
New Jersey Resources Corporation	5.00%	5.00%	0.00%
NiSource Inc.	9.50%	4.50%	5.00%
Northwest Natural Gas Company	6.50%	0.50%	6.00%
ONE Gas, Inc.	4.00%	2.50%	1.50%
Southwest Gas Corporation	10.00%	5.50%	4.50%
Spire, Inc.	4.50%	4.00%	0.50%

[61] Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, *Risk and Return for Regulated Industries*, 2017, at 99.

[62] Source: Schedule MLR-5a and Schedule MLR-5b.

Q. Have you evaluated the reasonableness of relying on *Value Line's* projected BVPS growth rates?

A. Yes. Since BVPS is the inverse DPS (*i.e.,* BVPS growth increases as earnings are retained), an expected change in the growth in DPS would also affect BVPS growth. Thus, given that *Value Line* does not expect EPS and DPS to grow at the same constant rate, Ms. Reno's reliance on *Value Line's* projected DPS and BVPS growth rates violate one of the primary assumptions of the constant growth DCF model.

Q. Why does Ms. Reno rely on sustainable growth rates?

A. Ms. Reno states that she relies on sustainable growth rates for one of her constant growth DCF scenarios because future earnings growth is directly a function of the amount of earnings retained and not paid as dividends to shareholders (i.e., the retention ratio).

Q. Do you agree with Ms. Reno's premise?

A. No. as noted above, the amount of earnings retained and not paid as dividends varies as a result of management decisions as opposed to earnings that are largely market-driven. These decisions can and do influence the amount of earnings retained versus paid out as dividends.

Q. Are there other reasons not to rely on the sustainable growth rate?

A. Yes. Ms. Reno's estimate of the sustainable growth rate would not be constant over the long-term and cannot be relied on as the estimate of growth in a constant growth DCF model. Ms. Reno's sustainable growth rates are calculated using *Value Line's* projections of the ROE and the retention ratio; however, as just shown in Figure 7, it is not reasonable to assume *Value Line's* projected DPS growth rates over the long-term term. Since *Value Line's* projected DPS growth rates are not expected to remain constant, then the dividend payout ratio is also not expected to remain constant over the long-term. Since the retention ratio is simply calculated as 1 minus the dividend payout ratio, it is therefore also affected by assumed changes in DPS growth.

Q. Is there academic research that supports your conclusion that future earnings growth is not directly a function of the amount of earnings retained as suggested by Ms. Reno?

A. Yes. Both Zhou and Ruland (2006) and Gwilym, et. al. (2006) discussed the theory that high dividend payouts (*i.e.,* low retention ratios) are associated with low future earnings growth.[63] Each of these studies also cited Arnott and Asness (2003) that found, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[64] Specifically, Arnott and Asness (2003) concluded:

> Unlike optimistic new-paradigm advocates, we found that low payout ratios (high retention rates) historically precede low earnings growth. This relationship is statistically strong and robust. We found that the empirical facts conform to a world in which managers possess private information that causes them to pay out a large share of earnings when they are optimistic that dividend cuts will not be necessary and to pay out a small share when they are pessimistic, perhaps so that they can be confident of maintaining the dividend payouts. Alternatively, the facts also fit a world in which low payout ratios lead to, or come with, inefficient empire building and the funding of less than-ideal projects and investments, leading to poor subsequent growth, whereas high payout ratios lead to more carefully chosen projects. The empire-building story also fits the initial macroeconomic evidence quite well. At this point, these explanations are conjectures; more work on discriminating among competing stories is appropriate.[65]

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[63] Zhou, Ping and Ruland, William. "Dividend Payout and Future Earnings Growth." Financial Analysts Journal, Vol. 62, No. 3, 2006; Gwilym, Owain, James Seaton, Karina Suddason, and Stephen Thomas. "International Evidence on the Payout Ratio, Earnings, Dividends and Returns." Financial Analysts Journal, Vol. 62, No. 1, 2006.

[64] Arnott, Robert and Clifford Asness. "Surprise: Higher Dividends = Higher Earnings Growth." Financial Analysts Journal, Vol. 59, No. 1, January/February 2003. Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

[65] *Id.*

All three studies found that there is a positive, not a negative or inverse, relationship between earnings growth rates and payout ratios. As such, Ms. Reno's reliance on the sustainable growth rates in the constant growth DCF model is not appropriate.

Q. Do you have other concerns regarding Ms. Reno's use of sustainable growth rates?

A. Yes. The use of the sustainable growth rates involves estimating investor expectations for four separate variables over the near-term: (1) the retention ratio, reflected as the "b" variable; (2) the expected return on book equity, reflected as the "r" variable; (3) the growth in the number of shares of common equity, reflected as the "s" variable; and (4) the portion of the market-to-book ratio that exceeds unity, reflected as the "v" variable. This means that the growth estimate includes the forecasting error of the four separate variables.

Q. What growth rates has the Commission used in the constant growth DCF analysis?

A. The Commission has historically preferred the use of analysts' projected EPS growth rates in the constant growth DCF analysis.[66] In fact, the Commission has noted the following:

> Upon our consideration of the record evidence, we find that I&E's DCF calculation correctly used forecasted earnings growth rates instead of considering historical growth rates. The record indicates that growth rate forecasts are made by analysts who already factor historical data into their forecasts of earnings per share growth. Although past performance can yield valuable information, relying on it for a DCF analysis results in placing too much weight on past performance. ***Thus, the best measure of growth for use in the DCF model are forecasted earnings growth rates***.[67]

[66] *See, e.g.,* Pennsylvania Public Utility Commission, Opinion and Order, October 4, 2018, at 93. *See, also*, Docket No. M-2018-3006643, Public Meeting held January 17, 2018, at 16, in which the Commission discusses the method it uses to set the ROE for the Distribution System Improvement Charge.

[67] Pennsylvania Public Utility Commission, Docket No. Docket No. R-2020-3018929, Opinion and Order, June 17, 2021, at 160; emphasis added.

Q. How would Ms. Reno's DCF results have changed if she had appropriately relied solely on projected EPS growth rates?

A. Ms. Reno's constant growth DCF analysis using EPS growth rates results in a range of 9.76 (*i.e.,* 30-day average share price) percent to 9.84 percent (*i.e.,* 90-day average share price).[68]

2. <u>Reliance on the Midpoint of the DCF Results to Determine the Recommended ROE</u>

Q. How did Ms. Reno determine her recommended ROE for Pike?

A. Ms. Reno's recommended ROE of 9.30 percent was based solely on the results of her constant growth DCF analysis. Specifically, Ms. Reno's recommended ROE was based on the midpoint of her DCF range of 8.71 percent to 9.84 percent, which was 9.27 percent.[69]

Q. Is Ms. Reno's methodology for determining the ROE in the current proceeding for Pike consistent with the methodology she has relied on in prior cases?

A. No, it is not. For example, in Docket No. 23-EKCE-775-RTS for Evergy Kansas Central, Inc. ("EKC") and Evergy Metro, Inc. ("EKM"), Ms. Reno similarly considered the constant growth DCF model to determine her recommended ROE for EKC and EKM, which produced a range of 8.66 percent to 9.76 percent and a midpoint of 9.21 percent.[70] However, Ms. Reno noted that, in determining her recommended ROE, she excluded the low-end of her DCF range because:

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[68] Reno Direct Testimony, at 47

[69] Reno Direct Testimony, at 53.

[70] Kansas Corporation Commission, Docket No. 23-EKCE-775-RTS, Direct Testimony of Maureen L. Reno, August 29, 2023, at 52

> they are unreasonable given current financial market conditions and interest rates. Furthermore, when the Commission approved the Companies' current ROE of 9.30%, the yield on 30-year Treasury bonds was 3.02%; now, the current rate is 4.02% (as of July 31, 2023).[71]

As a result, Ms. Reno based her recommended ROE for EKC and EKM on the midpoint of the high-end of her DCF range of 9.21 percent to 9.76 percent, which was 9.48 percent.[72]

Q. Does Ms. Reno acknowledge that the methodology she has relied on for determining her recommended ROE for Pike in the current proceeding deviates from the methodology she has relied on in prior cases?

A. Yes. Ms. Reno acknowledges that in prior proceedings she has excluded the low-end of her DCF range when determining her recommended ROE; however, she contends that she has not excluded the low-end of her DCF range in the current proceeding for Pike "given the circumstances specific to Pike and current financial market conditions".[73] However, beyond this statement, Ms. Reno does not identify the change in circumstances that warrants this change in her position. Taking this unsubstantiated position, Ms. Reno relies on the low-end of her DCF range in the current proceeding for Pike which ranges from 8.71 percent to 9.27 percent. This is a substantial change from the methodology used in Docket No. 23-EKCE-775-RTS for EKC and EKM where she excluded the low-end of her DCF range which similarly ranged from 8.66 percent to 9.21 percent.

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71 *Id.*

72 *Id.,* at 52-53.

73 Reno Direct Testimony, at 54.

Q. Why did Ms. Reno exclude the low-end of her DCF results in Docket No. 23-EKCE-775-RTS for EKC and EKM?

A. As noted above, Ms. Reno's constant growth DCF results produced a cost of equity range of 8.66 percent to 9.76 percent with a midpoint of 9.21 percent for EKC and EKM, which would have resulted in a recommended ROE of 9.20 percent had Ms. Reno relied on the entire DCF range. However, as Ms. Reno noted, the return authorized in the last rate proceeding for EKC and EKM of 9.30 percent was authorized when interest rates were much lower than they were when Ms. Reno filed her testimony in August 2023 for EKC and EKM. Therefore, Ms. Reno appears to recognize that the cost of equity had increased since the last rate proceeding for EKC and EKM and excluded the low-end of her DCF range so that her recommended ROE would be greater than the return authorized in EKC's and EKM's last rate proceeding.

Q. Do market conditions indicate an increase in the cost of equity since Pike's last rate proceeding?

A. Yes. As shown in Figure 2 above, the yield on the 30-year Treasury bond increased 233 basis points since the Commission approved the settlement agreement in the Company's last rate proceeding. Therefore, it is unclear why Ms. Reno would exclude the low-end of her DCF range in Docket No. 23-EKCE-775-RTS for EKC and EKM but rely on the low-end of her DCF range in the current proceeding for Pike.

Q. How would Ms. Reno's recommended ROE change if she determined her recommended ROE for Pike using the methodology she relied on in Docket No. 23-EKCE-775-RTS for EKC and EKM?

A. Ms. Reno's DCF results range from 8.71 percent to 9.84 percent with a midpoint of 9.27 percent. If Ms. Reno excluded the low-end of her DCF range, her recommended ROE range would be 9.27 percent to 9.84 percent, with a midpoint of 9.56 percent. While I disagree with the DCF results that rely on projected DPS, projected BVPS and sustainable growth rates for the reasons discussed above, had Ms. Reno determined her recommended ROE consistent with the methodology she relied on in Docket No. 23-EKCE-775-RTS for EKC and EKM, her recommended ROE would have increased from 9.30 percent to 9.60 percent.

3. <u>Weighting of the DCF results in the Final Recommendation</u>

Q. Do you agree with Ms. Reno's sole reliance on the DCF model?

A. No. As discussed in my response to Mr. Keller, Ms. Reno's decision to rely solely on the DCF model to determine the authorized return for Pike is inconsistent with the Commission's recent decisions for Aqua,[74] Columbia Water[75] and PAWC[76] where the Commission placed weight on the results of both the DCF and CAPM when determining the authorized ROE. Furthermore, as discussed in Section III above and in my response to Mr. Keller as well as acknowledged by Ms. Reno, interest rates are expected to remain elevated over the near-term and inflation is higher than the Federal Reserve's target.

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[74] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, at 154-155 (Order entered May 16, 2022).

[75] *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 107-108 (Order Entered January 18, 2024).

[76] *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, at 171-172 (Order Entered July 22, 2024).

Therefore, current market conditions are are consistent with those that resulted in the Commission relying on the results of the DCF and CAPM in the recent proceedings for Aqua, Columbia Water, and PAWC. As a result, Ms. Reno should have relied on both her DCF and CAPM results when developing her recommended ROE.

4. <u>Updated Constant Growth DCF Results</u>

Q. Did you update Ms. Reno's constant growth DCF analysis to reflect more recent market data?

A. Yes. I updated Ms. Reno's constant growth DCF analysis to reflect market data (*i.e.,* share prices, dividends, and growth rates) through March 31, 2025. Additionally, I only updated Ms. Reno's constant growth DCF that relied on projected EPS growth rates, excluding her constant growth DCF analyses that relied on projected DPS, BVPS, and sustainable growth rates. As shown in Exhibit CMW-7R, when Ms. Reno's analysis is updated with current data, the median cost of equity for her 30-day average constant growth DCF using projected EPS growth rates is 10.37 percent while the median cost of equity for her 90-day average constant growth DCF using projected EPS growth rates is 10.53 percent. The updated constant growth DCF range of 10.37 percent to 10.53 percent is greater than the Company's requested ROE of 10.20 percent.

C. <u>CAPM Analysis</u>

Q. Please summarize Ms. Reno's application of the CAPM.

A. Ms. Reno conducts three forms of the CAPM analysis. Ms. Reno's first CAPM reflects a risk-free rate that is the 30-day average of the 30-year Treasury bond yield, current betas for her proxy group as reported by *Value Line*, and a market risk premium based on the historical arithmetic average real return on large company common stocks from 1926 to

2023 less the income-only return on Treasury bond investments over that same period as reported by *Kroll.* Ms. Reno's second CAPM reflects the same risk-free rate and betas as her first CAPM scenario, but a market risk premium that is based on the long-horizon supply-side market risk premium published by *Kroll.* Ms. Reno's last CAPM scenario reflects the same betas as in her first two scenarios, but a "normalized" risk-free rate and a projected market risk premium, both published by *Kroll.* The results of Ms. Reno's CAPM analyses range from 8.06 percent to 11.24 percent.[77] Ms. Reno states that she does not base her ROE recommendation on the results of the CAPM analyses, but rather uses the results of her CAPM analysis as a check on her DCF results.

Q. What are the primary areas where you disagree with Ms. Reno's CAPM analyses?

A. My primary areas of disagreement are (1) Ms. Reno's incorrect reliance on *Kroll's* "normalized" risk-free rate when estimating the CAPM using the *Kroll's* recommended market risk premium, (2) Ms. Reno's selection of the market risk premia (*i.e.,* use of the *Kroll* recommended market risk premium, historical market risk premium and supply-side market risk premium), and (3) use of the historical market risk premium and supply-side market risk premium for the period of 1926-2023 which is outdated as *Kroll* has updated both to reflect the period of 1926-2024.

[77] Reno Direct Testimony, at 50-51.

Q. As a threshold matter, is the cost of equity estimate resulting from Ms. Reno's CAPM analysis that relies on the *Kroll* recommended market risk premium and risk-free rate reasonable?

A. No. The result of Ms. Reno's CAPM that assumes the *Kroll* recommended market risk premium is 8.06 percent, which is well below any authorized ROE in decades for a natural gas utility in a jurisdiction with a comparable regulatory framework as Pennsylvania.

Q. Have you identified an error in Ms. Reno's CAPM analysis that relies on the *Kroll* recommended market risk premium and risk-free rate?

A. Yes. Ms. Reno incorrectly relies on *Kroll's* "normalized" risk-free rate of 3.50 percent as *Kroll* does not currently recommend strictly using the "normalized" risk-free rate with the *Kroll* recommended market risk premium. In fact, *Kroll* recommends using the higher of either the normalized risk-free rate or the spot yield on the 20-year Treasury bond. As of February 28, 2025 (*i.e.,* the end of the analytical period relied on by Ms. Reno), the yield on the 20-year Treasury Bond was 4.55 percent, which is substantially greater than *Kroll's* "normalized" risk-free rate of 3.50 percent.

Q. Does Mr. Keller also use *Kroll's* "normalized" risk-free rate in his CAPM that relies on *Kroll's* recommended market risk premium?

A. No. Mr. Keller adheres to *Kroll's* recommendation and instead relies on the spot yield on the 20-year Treasury Bond of 4.55 percent as of December 9, 2024 in his CAPM scenario that relies on *Kroll's* recommended market risk premium because the spot yield is greater than *Kroll's* "normalized" risk-free rate of 3.50 percent.[78]

[78] Keller Direct Testimony, at 30.

Q. How does the result of Ms. Reno's CAPM analysis that relies on *Kroll's* recommended market risk premium change if the correct risk-free rate is used?

A. As shown in Exhibit CMW-8R, had Ms. Reno correctly relied on the spot yield on the 20-year Treasury bond as opposed to *Kroll's* normalized risk-free rate, the cost of equity result for her CAPM that relies on *Kroll's* recommended market risk premium increases 105 basis points from 8.06 percent to 9.11 percent. The correction would also result in an updated CAPM range of 9.11 percent to 11.24 percent with a midpoint of 10.18 percent as opposed to Ms. Reno's filed CAPM range of 8.06 percent to 11.24 percent with a midpoint of 9.65 percent.

Q. Are the market risk premia specified by Ms. Reno in her CAPM analyses consistent with the inverse relationship between interest rates and the market risk premium?

A. No. Ms. Reno's market risk premia do not reflect the inverse relationship between interest rates and the market risk premium. Given that current yields on Treasury bonds are lower than yields historically, and there is an inverse relationship between interest rates and the market risk premium, Ms. Reno's market risk premia in her CAPM analysis understate the market risk premium in the current market environment. For example, the historical income-only return on long-term government bonds over the period 1926 to 2023[79] has been 4.87 percent;[80] however, the current income-only return or yield on 30-year Treasury bonds that Ms. Reno relies on to estimate her CAPM is lower at 4.70 percent. Because

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[79] The period of 1926-2023 was used for consistency with Ms. Reno's use of the historical market risk premium over the period of 1926-2023. The conclusion would not change if data for the period of 1926-2024 from *Kroll* was used. Further, as will be discussed in more detail below, I update Ms. Reno's CAPM to reflect the historical market risk premium and supply-side market risk premium for the period of 1926-2024.

[80] The market risk premium from 1926-2023 is calculated as the average return on the S&P 500 Index from 1926-2023 (12.04 percent) minus the average income-only return on long-term government bonds over the same time-period (4.87 percent). Kroll, Cost of Capital Navigator, 2023.

current interest rates on long-term government bonds are below the historical average interest rate of those same bonds, the inverse relationship between interest rates and the market risk premium implies that the market risk premium should be above the long-term historical average market risk premium of 7.17 percent. However, as shown in Figure 8, the market risk premia on which Ms. Reno relies are at or well below the long-term historical average. Ms. Reno's market risk premium assumptions are inconsistent with the historical inverse relationship between interest rates and the market risk premium.

Figure 8: Misalignment of Market Risk Premia Relied on by Ms. Reno

Source	Market Risk Premium	Amount Below Long-Term Avg.	Risk-Free Rate	Amount Below Long-Term Avg.
Long-Term Historical Avg.	**7.17%**		**4.87%**	
Reno (*Kroll* Historcial Arithmetic	7.17%	0.00%	4.70%	-0.17%
Reno (*Kroll* historical Ibbotson/Chen)	6.22%	-0.95%	4.70%	-0.17%
Reno (*Kroll* Recommeded)	5.00%	-2.17%	3.50%	-1.37%

Q. Why is it inappropriate to use a historical market risk premium in the CAPM to estimate the cost of equity?

A. The cost of equity that is being set in this proceeding is the return that investors expect on current and future investments in the Company. Therefore, the market return and market risk premium fundamentally should be forward-looking. Ms. Reno has not provided any evidence that the historical average market return or the market risk premium that she relies on reflect the expected market conditions during the period in which the Company's proposed rates will be in effect. *Morningstar*, which is the prior publisher of the historical dataset relied on by Ms. Reno for her CAPM that is now published by *Kroll*, specifically supports that the market risk premium should be a forward-looking, not historical, analysis:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[81]

Given that the current and projected market conditions that both Ms. Reno and I have discussed affect the current and projected equity risk premium, a forward-looking market return and market risk premium should be used in the CAPM analysis for estimating the cost of equity.

Q. Has *Kroll* also highlighted a potential inconsistency with relying on historical data for a forward-looking analysis such as the CAPM?

A. Yes. *Kroll* has stated that, "[i]n using a historical measure of the equity risk premium, one assumes that what has happened in the past is representative of what might be expected in the future."[82] As discussed above, because the current long-term government bond yields are currently below those that Ms. Reno relies on in her historical average market risk premium estimates, the market risk premium based on long-term historical average data is certainly not representative of what is expected in the future. Given the inverse relationship between interest rates and the market risk premium, and since the current interest rate that Ms. Reno relies on for her risk-free rate is *lower* than the historical average, it is reasonable to expect that the current market risk premium should be *higher* than the historical average market risk premium.

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81 *Morningstar Inc*., 2010 Ibbotson SBBI Valuation Yearbook, at 55.

82 *Kroll*, 2022 SBBI Yearbook, at 198.

Q. Is there also evidence that the use of a historical market premium can produce counter-intuitive results?

A. Yes. Figure 9 illustrates the problem with relying on a historical market risk premium such as Ms. Reno has done. Specifically, the figure shows that from 2007-2009, the historical market risk premium decreased even as market volatility (the primary statistical measure of risk) significantly increased. Further, this figure demonstrates the significant swings in the annual equity risk premium that are averaged into the long-term historical average calculations. As shown, in 2008, the annual equity risk "premium" was actually negative, which implies a discount for equity holders relative to the cost of debt. It is incomprehensible that the perceived risk for equity was negative (implying a required equity return lower than the cost of debt) in the height of the financial market collapse when the overall market return for equities was negative 37 percent. The assumption that investors would expect or require an equity risk "premium" below the cost of debt during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. In fact, as shown, this individual observation alone, which runs counter to the theory of the equity risk premium, reduces the historical average market risk premium for the prior 80 years by 60 basis points.

Figure 9: Historical Market Risk Premium and Market Volatility

	Market Volatility	Market Return	Annual Equity Risk Premium	Long-term Average Historical Market Risk Premium[83]
2007	17.54	5.49%	0.63%	7.10%
2008	32.69	-37.00%	-41.45%	6.50%
2009	31.48	26.46%	3.47%	6.70%

[83] Ibbotson SBBI Yearbook. *Morningstar Inc*. 2008, at 28. *Ibbotson SBBI Yearbook. Morningstar Inc*. 2009, at 23; Ibbotson SBBI Yearbook. *Morningstar Inc*. 2010, at 23. The historical market risk premium equals the total return on large company stocks less the income-only return on long-term government securities.

Q. Did you develop a forward-looking estimate of the market risk premium in the current proceeding for Pike?

A. No, I did not. While I do not agree with the use of either *Kroll's* recommended market risk premium or a historical market return and historical market risk premium to estimate the cost of equity for all of the reasons discussed above, I have not estimated a forward-looking market risk premium because, as I will show below, when reasonable adjustments are applied to Ms. Reno's CAPM analyses, the results provide support for the Company's requested ROE of 10.20 percent.

Q. Did Ms. Reno rely on the most recent estimates of the historical market risk premium and supply-side market risk premium reported by *Kroll*?

A. No. As noted above, Ms. Reno relied on the historical market risk premium and supply-side market risk premium as reported by *Kroll* for the period of 1926-2023. However, *Kroll* updated the historical market risk premium and supply side market risk premium to include 2024 on February 3, 2025, which was well before Ms. Reno filed testimony in this proceeding and before the end of the analytical period (*i.e.,* February 28, 2025) that she relied on to estimate her CAPM analysis. Therefore, Ms. Reno should have relied on the historical market risk premium and supply-side market risk premium for the period of 1926-2024 in her CAPM analysis.

Q. Have you adjusted Ms. Reno's CAPM analyses to address some of the problems you have identified?

A. Yes. Specifically, I adjusted Ms. Reno's CAPM analysis to: (1) rely on the spot yield on the 20-year Treasury Bond as recommended by *Kroll* when also relying on *Kroll's* recommended market risk premium; (2) rely on the historical arithmetic average market risk premium and supply-side market risk premium reported by *Kroll* for the period of 1926-2024; and (3) reflect market data through March 31, 2025.[84] As shown in Figure 10 (see also Exhibit CMW-8R), applying these reasonable updates and corrections to Ms. Reno's CAPM analyses results in a cost of equity range of 9.18 percent to 11.27 percent with a midpoint of 10.23 percent.[85]

Figure 10: Summary of Adjustments to Ms. Reno's CAPM Analysis

	Historical MRP	Supply-Side MRP	Kroll Recommended MRP	Range	Midpoint
As Filed	11.24%	10.37%	8.06%	8.06% to 11.24%	9.65%
As Adjusted (Kroll MRP - Spot Yield / Hist. MRP & S.S. MRP (1926-2024)	11.37%	10.41%	9.11%	9.11% to 11.37%	10.24%
As Updated (As of March 31, 2025)	11.27%	10.31%	9.18%	9.18% to 11.27%	10.23%

D. <u>Overall Effect of Changes to Ms. Reno's Cost of Equity Analyses</u>

Q. Based on the various issues that you have identified with Ms. Reno's DCF and CAPM analyses, what would the results of those analyses, when updated and corrected, indicate for an overall cost of equity for the Company in this proceeding?

A. Figure 11 presents the results of Ms. Reno's analyses when they are updated to use the most current data available and corrected for the issues that I have discussed. Specifically, the changes to Ms. Reno's constant growth DCF and CAPM analyses are shown in Exhibit

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[84] I relied on market data through March 31, 2025 to update Ms. Reno's CAPM analyses; however, on April 15, 2025, *Kroll* increased its recommended market risk premium from 5.00 percent to 5.50 percent. Therefore, the adjusted CAPM results are likely conservative given the recent change in *Kroll's* recommended market risk premium.

[85] While I do not agree with the use of either *Kroll's* recommended market risk premium or a historical market return and historical market risk premium to estimate the CAPM as these estimates likely understate market risk premium and cost of equity in the current market environment, applying the adjustments discussed results in CAPM results that support the Company's requested ROE of 10.20 percent. As a result, I have limited my response and did not calculate a version of the CAPM relying on the forward-looking market risk premium that I have relied on in prior proceedings.

CMW-7R and Exhibit CMW-8R, respectively. As shown in Figure 11, the midpoint of Ms. Reno's constant growth DCF analyses increases from 9.27 percent to 10.45 percent while the midpoint of her CAPM analyses increases from 9.65 percent to 10.23 percent. Further, considering the adjustments and the Commission's decisions in the recent rate proceedings for Aqua, Columbia Water, and PAWC where the Commission placed weight on the results of the CAPM in determining the ROE, simply placing equal weight on the adjusted results of Ms. Reno's DCF and CAPM analysis would result in a cost of equity of 10.34 percent, which provides support for the Company's requested ROE of 10.20 percent in this proceeding.

Figure 11: Adjusted Results of Ms. Reno's Cost of Equity Estimation Models

	As Filed	Adjusted/ Corrected	Updated/ Adjusted/ Corrected
Constant Growth DCF			
30-Day Avg.			
Proj. EPS Growth Rates	9.76%	9.76%	10.37%
Proj. EPS, BVPS & DPS Growth Rates	8.83%	Excl.	Excl.
Sustainable Growth Rate	8.74%	Excl.	Excl.
90-Day Avg.			
Proj. EPS Growth Rates	9.84%	9.84%	10.53%
Proj. EPS, BVPS & DPS Growth Rates	8.85%	Excl.	Excl.
Sustainable Growth Rate	8.71%	Excl.	Excl.
Midpoint	**9.27%**	**9.80%**	**10.45%**
CAPM			
Historical MRP	11.24%	11.37%	11.27%
Supply-Side MRP	10.37%	10.41%	10.31%
Kroll Recommended MRP	8.06%	9.11%	9.18%
Midpoint	**9.65%**	**10.24%**	**10.23%**
Average of DCF and CAPM	**9.46%**	**10.02%**	**10.34%**

E. <u>Business and Regulatory Risks</u>

Q. What has Ms. Reno stated regarding the business and regulatory risks of the Company?

A. Ms. Reno concludes that the Company has comparable business risk relative to the companies included in her proxy group because the Kroll Bond Rating Agency ("KBRA") has classified Pike and the parent company of Pike, CEC, as having "average" business risk with the subcategory of industry risk classified as "strong".[86] Further, Ms. Reno also concludes that the Company has comparable regulatory risk relative to her proxy group due to ratemaking mechanisms that allow Pike to reduce regulatory lag such as the currently approved gas cost rate, state tax adjustment surcharge, Distribution System Improvement Charge ("DSIC") and use of a forecast test year as well as the Company's proposed Weather Normalization Adjustment Mechanism ("WNA").[87]

Q. What is your concern with Ms. Reno's use of the credit rating for CEC to assess the business risk of Pike's natural gas operations in Pennsylvania?

A. I have three primary concerns with Ms. Reno's use of CEC's credit rating to assess the business risk profile of Pike's natural gas operations in Pennsylvania:

- KBRA's credit rating is an assessment of the risks of CEC, the parent company of Pike, and not Pike. Thus, Ms. Reno's consideration of the credit rating for CEC violates the stand-alone principle of ratemaking, which requires that rates should be based on the risk and benefits of the regulated utility, not its investors, parent or affiliates.[88] The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. To maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, in the current proceeding, the

[86] Reno Direct Testimony, at 33.

[87] *Id.,* at 36-40.

[88] Morin, Dr. Roger A. *New Regulatory Finance*. Public Utilities Reports, Inc., 2006, at 215-216.

cost of equity should reflect the investor required return for Pike's natural gas operations in Pennsylvania.

- Credit ratings do not consider all of the risk to equity holders as compared with the proxy group. Credit ratings are assessments of the likelihood a company could default on its debt, whereas the topic of the current proceeding is to determine the riskiness and cost of the Company's equity. In addition, while credit rating agencies consider the business risks of an individual company, when establishing its debt credit rating, they do not conduct a comparative analysis of business risks relative to the proxy group. The development of the investor-required return is based on a proxy group of risk-comparable companies. In developing the proxy group, it is essential to balance the relative risk of the companies included in the proxy group with the overall size of the group. Therefore, it is always the case that the proxy companies do not have exactly the same risk profile as the subject company. As such, it is reasonable to review the relative risks of the proxy group companies and the subject company to determine how the subject company's risk profile compares with the group to determine the appropriate placement of the ROE within the range of results established using the proxy group companies.

- Finally, while I do not agree with Ms. Reno's use of CEC's credit rating to assess the business risk of Pike's natural gas operations in Pennsylvania relative to the proxy group for the reasons discussed above, a comparison of CEC's credit rating to the average credit rating of the proxy group would not support Ms. Reno's conclusion that the business risk of Pike is comparable to the proxy group. For example, KBRA's credit rating for CEC of BB is well below the average credit rating of Ms. Reno's proxy group of A-/BBB+ from S&P and A3/Baa1 from Moody's, [89] which indicates greater risk relative to the proxy group.

Q. What is your concern with Ms. Reno's conclusion that the Company's regulatory risk is comparable to the proxy group because of the Company's approved and proposed regulatory mechanisms such as the use of a forecast test year, DSIC, gas cost rate, state tax adjustment surcharge and WNA?

A. My primary concern is Ms. Reno has not evaluated the regulatory mechanisms approved for the companies in the proxy group, which is necessary to draw a conclusion regarding the regulatory risk of the Company relative to the proxy group. Ms. Reno acknowledges that such as comparison is important as she noted when discussing business risk that "[t]he

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[89] Reno Direct Testimony, at 34-35.

fundamental comparison here is to the proxy group".[90] However, Ms. Reno does not review each of the proxy group companies and instead only provides general references such as this statement in regard to the prevalence of forecast test years: "S&P MI reports that less than a quarter of states allow a future test year".[91]

Q. What analysis should be conducted to evaluate the Company's regulatory risk?

A. The appropriate approach is to compare the regulatory mechanisms of the Company to the regulatory mechanisms of the proxy group being used to develop the ROE to determine if a company has greater regulatory risk than the proxy group. If the company is determined to have greater/less risk than the proxy group due to having fewer comprehensive regulatory mechanisms, then an ROE towards the higher/lower end of the proxy group results may be warranted. Since Ms. Reno has not developed such a comparison, there is no basis for her to comment on the regulatory risk of Pike as compared to the proxy group.

Q. Have you conducted an analysis to compare the regulatory mechanisms of Pike to the regulatory mechanisms approved in the jurisdictions in which the companies in Ms. Reno's proxy group operate?

A. Yes. I selected four mechanisms that are important to provide a regulated utility an opportunity to earn its authorized ROE. These are: (1) fuel cost recovery; (2) test year convention (*i.e.,* forecast vs. historical); (3) use of rate design and/or other mechanisms that mitigate volumetric risk and stabilize revenue; and 4) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit CMW-9R and summarized below:

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[90] *Id.,* at 34.

[91] *Id.,* at 37.

- Fuel Cost Recovery: The Company has the gas cost rate to recover the cost of purchased gas, which is updated annually and also allows for the variances between actual gas costs and projected gas costs to be recovered from or refunded to customers. Similarly, as shown in Exhibit CMW-9R, approximately 96.43 percent of the operating companies in Ms. Reno's proxy group either provide service in a state that has restructured where customers obtain either electricity or natural gas from competitive suppliers; therefore, negating the need for a fuel cost recovery mechanism with a true-up between actual and forecasted fuel costs or are allowed to directly recover the full cost of fuel, purchased power and purchased gas costs from customers, without either a dead band or sharing band.

- Test Year Convention: The Company uses a forecasted test year in Pennsylvania. Similarly, approximately 53.57 percent of the utility operating subsidiaries of the companies in Ms. Reno's proxy group use either fully forecasted or partially forecasted test years. This highlights the concern with Ms. Reno's analysis as she noted that less than 25 percent of states allow a future test year; however, had she reviewed each of the operating subsidiaries of the companies in her proxy group she would have concluded that over half operate in a jurisdiction that allows either a partially or fully forecasted test year.

- Volumetric Risk: As discussed above, Pike is proposing a WNA which would allow the Company to recover from or refund to customers the under- or overcollection of revenue associated with deviations from normal weather. Similarly, approximately 82.14 percent of the utility operating subsidiaries of Ms. Reno's proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

- Capital Cost Recovery: The Company does have the DSIC with allows Pike to recover the costs associated with replacing and repairing aging natural gas infrastructure. Similarly, approximately 75 percent of the utility operating subsidiaries of Ms. Reno's proxy group companies have some form of capital cost recovery mechanism in place.

Q. What is your conclusion regarding the perceived risks related to the regulatory environment in Pennsylvania?

A. Considering the regulatory adjustment mechanisms, similar to Pike, many of the companies in Ms. Reno's proxy group have timely cost recovery through fuel cost recovery riders, forecasted test years, cost recovery trackers and revenue stabilization mechanisms. As a result, I conclude that if the Company's proposed WNA is approved, Pike's regulatory risk would be similar to that of Ms. Reno's proxy group. However, it is important to note that this analysis assumes that the Company's proposed WNA will be approved. In the event that the Commission does not approve the Company's proposal, the volumetric risk of Pike would be greater than that of the proxy group, on average.

Q. Are there any additional business risks that Ms. Reno failed to consider when assessing the business risk of Pike relative to her proxy group?

A. Yes, Ms. Reno has not considered the risk associated with the Company's small size.

Q. Is there a risk to a firm associated with small size?

A. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[92]

Q. How does the smaller size of a utility affect its business risk?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put

92 Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q. How do Pike's natural gas operations in Pennsylvania compare in size to the companies in Ms. Reno's proxy group?

A. The Company's natural gas operations are substantially smaller than the median for the proxy group companies in terms of market capitalization. While Pike is not publicly-traded on a stand-alone basis, as shown on Exhibit CMW-10R, Pike's common equity based on its proposed test year rate base and equity ratio is substantially smaller than the median market capitalization of Ms. Reno's proxy group companies.

Q. How did you estimate the risk premium related to Pike's relatively small size?

A. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[93] As shown in Exhibit CMW-10R, the median market capitalization of the proxy group is approximately $4.64 billion, which corresponds to the fifth decile of *Kroll's* market capitalization data.[94] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.74 percent (*i.e.*, 74 basis points). In comparison, Pike's common equity of approximately 5.41 million falls within the tenth decile, which corresponds to a size premium of 4.47 percent (*i.e.*, 447 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 373 basis points (*i.e.*, 4.47 percent minus 0.74 percent).

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[93] *Kroll*, Cost of Capital Navigator – Size Premium: Annual data as of 12/21/2024.

[94] *Id*.

Q. Were utility companies included in the small size risk premium study conducted by *Kroll*?

A. Yes. As shown in Exhibit 7.2 of *Kroll's* 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile, which indicates that *Kroll* has included utility companies in its size risk premium study.[95]

Q. Is the size premium applicable to companies in regulated industries such as utilities?

A. Yes. For example, in his article "Utility stocks and the size effect – revisited," Thomas Zepp provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[96] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[97]

Additionally, Chrétien and Coggins studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[98] One of the subgroups was a group of natural gas companies that contained many of the same

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95 Duff & Phelps, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

96 Zepp, Thomas M, "Utility Stocks and the Size Effect—Revisited,"*The Quarterly Review of Economics and Finance*, Vol. 43, No. 3, 2003, at 578–582; accessed at: https://www.sciencedirect.com/science/article/abs/pii/S1062976902001722?via%3Dihub.

97 *Id*.

98 Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, Vol. 18, No. 2, 2011, accessed at: https://energystudiesreview.ca/esr/article/view/531.

natural gas companies included in Ms. Reno's proxy group.[99] The article considered the CAPM, the Fama-French three-factor model, and the Empirical CAPM. In the article, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[100]

Q. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[101] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[102] Similarly, in Order No. 19, the RCA noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk,

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99 The U.S. natural gas utility group included: AGL Resources Inc., Atmos Energy Corp., Laclede Group, New Jersey Resources Corp., Northwest Natural Gas Co., Piedmont Natural Gas Co., South Jersey Industries, Southwest Gas Corp. and WGL Holdings Inc.

100 Chrétien, Stéphane, and Frank Coggins. "Cost of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, Vol. 18, No. 2, 2011, accessed at: https://energystudiesreview.ca/esr/article/view/531.

101 Docket No. U-10-29, In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by Alaska Electric Light and Power Company, Order entered September 2, 2011 (Order No. 15), at 37.

102 *Id.*, at 32 and 37.

geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[103] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[104]

Additionally, in Docket No. E017/GR-15-1033 for Otter Tail Power Company ("Otter Tail"), the Minnesota Public Utilities Commission ("Minnesota PUC") selected an ROE above the mean DCF results, as a result of multiple factors including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[105]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") has relied on a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was

[103] Docket No. U-16-066, In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR Natural Gas Company, A Division of SEMCO Energy, Inc., Order entered September 22, 2017 (Order No. 19), at 50-52.

[104] *Id.*

[105] Order in Docket No. E017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (May 1, 2017), at 55.

necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[106]

Q. What are your conclusions regarding the effect of the Company's regulatory risk and small size on Pike's business risk and cost of equity?

A. While I conclude that the regulatory risk of the Company is comparable to that of Ms. Reno's proxy group, were Pike's proposed WNA to be approved, the Company has substantial risk associated with the small size of its natural gas operations in Pennsylvania. Therefore, I conclude that the Company has greater business risk than Ms. Reno's proxy group warranting an ROE towards the high-end of the range of results. Further, I conclude that because Ms. Reno does not consider the small size of the Company in her assessment of Pike's business risk, she incorrectly concludes that the Company has business risk that is similar to her proxy group.

F. <u>Capital Structure</u>

Q. What has Ms. Reno recommended regarding the Company's capital structure?

A. Ms. Reno proposes to accept the Company proposed capital structure composed of 50.63 percent common equity, 40.73 percent long-term debt, and 8.64 percent short-term debt but recommends that Pike's equity ratio of 50.63 percent be "established as a maximum".[107] Ms. Reno suggests that her recommendation to establish a "maximum"

[106] Federal Energy Regulatory Commission, Opinion No. 569-A, May 21, 2020, at para 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

[107] Reno Direct Testimony, at 23.

equity ratio of 50.63 percent is based on: (1) a review of the actual equity ratios of the companies in her proxy group; and (2) the equity ratio of Pike's parent company, CEC.

Q. How do you respond to Ms. Reno's comparison of the capital structure of the Company to the capital structures of the holding companies in the proxy group?

A. I have two primary concerns with Ms. Reno's comparison of the Company's proposed equity ratio to the equity ratios of the proxy group. First, it is not appropriate to compare Pike's proposed equity ratio to the average equity ratio of the proxy group at the holding company level such as Ms. Reno has done.

Second, while it is not appropriate, if the capital structures at the holding company level are considered, the market value of debt and equity must be used to estimate the percentage of debt and equity in the capital structure, not the book value of debt and equity as used by Ms. Reno.

Q. Why is it inappropriate to rely on the holding company capital structures to set the capital structure for the operating company?

A. The holding company data includes corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities. The relevant capital structure for comparison purposes to the Company is at the operating company level, not the holding company. The Commission should establish rates by evaluating Pike on a stand-alone basis from its parent. Therefore, it is reasonable and appropriate to rely on the operating company capital structures that have been used to fund utility operations for the comparison of the Company to other natural gas utilities. In contrast, relying on the proxy group capital structures, as Ms. Reno has done, will result in a ratemaking capital structure for the Company that reflects the capital structures, risks, and capital costs of unregulated affiliates, and the financial diversification of the proxy group holding companies, which is contrary to the stand-alone principle of ratemaking.

Q. Is the proposed equity ratio for Pike consistent with the equity ratios of the operating utility subsidiaries of the proxy group?

A. Yes. As shown in Exhibit CMW-11R, I reviewed the Company's proposed capital structure and the capital structures of the utility operating subsidiaries of Ms. Reno's proxy companies. The median actual common equity ratio for the period of 2021-2023 for Ms. Reno's proxy group at the operating subsidiary level was 53.64 percent. Therefore, Pike's proposed equity ratio of 50.63 percent is well below the median equity ratio for the utility operating subsidiaries of the proxy group companies indicating that, all else equal, the Company has greater financial risk than the proxy group. Thus, considering the equity ratios for the proxy group companies at the operating subsidiary level, I recommend the Commission disregard Ms. Reno's recommendation to set the Company proposed equity ratio of 50.63 percent as the "maximum" equity ratio.

Q. Please explain why the book value of the capital structures of the proxy group companies should not be relied upon in benchmarking the proxy group capital structures to the Company's capital structure.

A. The use of the book value of debt and equity for the proxy group companies at the holding company level creates a mismatch between the capital structure data that is being used to determine the reasonableness of the Company's equity ratio and the data that is being used in the models to determine the cost of equity for the Company. Ms. Reno considers the results of the DCF model to determine the cost of equity for the Company. In her constant growth DCF model, she estimates the dividend yield based on the expected dividends of the proxy group companies and their respective current stock prices (*i.e.*, which is the current *market value* of their equity). Similarly, Ms. Reno also considers the CAPM to estimate the cost of equity for the Company, and in doing so, relies on beta coefficients that reflect the returns of each of the proxy group companies based on their respective *market value*. Therefore, based on the assumptions relied upon by Ms. Reno, the cost of equity estimates that she has developed represent the return required by investors on the *market* value of equity not the *book* value.

Q. What is the effect of relying on the required return on the market value of equity for assessing the cost of equity, but then the book value of debt and equity for assessing the capital structure?

A. If the market value of debt and equity are substantially different than the book value of debt and equity, then the resulting cost of equity estimate would not reflect the financial risk of the book value capital structure. This is illustrated in the following set of equations found readily in corporate finance textbooks.[108] As shown in Equation [1], the value of a company (or asset) is determined as follows:

$$\mathrm{V} = \mathrm{D} + \mathrm{E} \qquad [1]$$

Where:

V = Market value of a company/asset

D = Market value of debt

E = Market value of equity

For simplicity, if it is assumed that there are no taxes, based on Equation [1], the total return on V can be estimated as follows:

$$r_V = \frac{\mathrm{D}}{\mathrm{D} + \mathrm{E}} \text{ x } r_D + \frac{\mathrm{E}}{\mathrm{E} + \mathrm{D}} \text{ x } r_E \qquad [2]$$

[108] Brealey, Myers, and Allen, *Principles of Corporate Finance,* 13th Ed., 2020, at 452-462.

Where:

r_V = expected return on assets / weighted-average cost of capital

r_D = expected return on debt

r_E = expected return on equity

Then, Equation [2] can be rearranged into the following form to solve for the expected return on equity, r_E:

$$r_E = r_V + (r_V - r_D)\frac{D}{E} \qquad [3]$$

As shown in Equation [3], the expected return on the market value of equity is a function of the market debt-to-equity ratio. As the percentage of debt increases, the financial risk of the firm increases, and thus investors require a higher return to compensate for the additional financial risk. Therefore, if the book debt-to-equity ratio for the proxy group is substantially different than market debt-to-equity ratio, the expected return on equity will also be substantially different.

Q. Is the book value debt-to-equity ratio different from the market value debt-to-equity ratio?

A. Yes. Exhibit CMW-12R presents the average market value common equity ratio for Ms. Reno's proxy group as of December 31, 2024.[109] As shown therein, the median common equity ratio for Ms. Reno's proxy group is 57.87 percent. Given that Ms. Reno estimates the cost of equity in the DCF and CAPM analyses based on the market value of the proxy group companies' equity, this means that the cost of equity she estimates reflects the financial risk of a market value common equity ratio of 57.87 percent. Based on this analysis, the market value common equity ratio is significantly greater than the median

109 Note, this represents the data most currently available as at the time of the preparation of my rebuttal testimony.

book value equity ratio of 45.50 percent that Ms. Reno relied on to benchmark the Company's proposed equity ratio of 50.63 percent. Therefore, it is reasonable to conclude that had Ms. Reno correctly relied on the market value of debt and equity instead of the book value she would not have recommended that the "maximum" equity ratio be set at 50.63 percent.

Finally, given the greater financial risk associated with the increased leverage of the book value capital structures of the proxy group companies cited by Ms. Reno, investors would require a much higher cost of equity than estimated by her DCF and CAPM analyses. In this case, relying on a cost of equity estimate based on market values but a capital structure based on book values, results in the incorrect conclusion that a return reflecting the financial risk of the market value equity ratio would be sufficient to compensate investors for a much more highly levered capital structure based on book value.

Q. Ms. Reno also compares the Company's proposed equity ratio with authorized equity ratios nationally. Is the comparison conducted by Ms. Reno accurate?

A. No. There are a number of problems with her analysis:

- Ms. Reno's review of authorized equity ratios for natural gas utilities since 2020 improperly includes the capital structures authorized in Arkansas, Florida, Indiana, and Michigan that include deferred taxes and other credits as zero cost/low-cost components in the capital structure. These additional items have the effect of reducing both the equity and debt ratios used to establish the rate of return, which in turn produces results that are not comparable to authorized equity ratios in other states.
- Ms. Reno includes limited-issue rider cases; however, these cases should be excluded as they address only a specific issue or issues, and not a utility's entire operations.

- The analysis conducted by Ms. Reno only relies on the mean authorized equity ratios for natural gas utilities. Ms. Reno does not consider the range of equity ratios that have been authorized for natural gas utilities.

Q. Did you compare the Company's proposed equity ratio with the equity ratios that have been authorized for natural gas utilities from 2020 through 2024?

A. Yes. Specifically, I reviewed the authorized equity ratios for natural gas utilities across the U.S. from 2020 through 2024, excluding both limited issue rider cases and authorizations in Arkansas, Indiana, Michigan, and Florida due to the inclusion of zero-cost capital in the capital structure. As shown in Figure 12, Pike's proposed equity ratio of 50.63 percent is below the mean equity ratio for natural gas utilities across the U.S. from 2020-2024 and well below the high-end which ranged from 59.88 percent to 62.38 percent. Therefore, Ms. Reno's recommendation to set the maximum equity ratio for Pike at 50.63 percent is also not supported by a review of authorized equity ratios for natural gas utilities across the U.S.

Figure 12: Range of Annual Authorized Equity Ratios for Natural Gas Utilities, 2020-2024[110]

Year	Average	Min.	Max.
2020	52.39%	48.00%	60.12%
2021	51.88%	47.45%	59.88%
2022	51.80%	47.00%	60.59%
2023	52.04%	48.00%	62.20%
2024	52.46%	45.30%	62.38%

[110] S&P Capital IQ Pro.

Q. Do you agree with Ms. Reno's consideration of CEC's equity ratio in her evaluation of the Company's proposed equity ratio?

A. No. The basis for Ms. Reno's consideration of CEC's equity ratio is that it is below Pike's and therefore, CEC uses double leverage; however, this logic runs counter to financial theory.[111] While the capital structure and the cost of capital are intended to reflect the risks of the operations of the company, which in this case is Pike, the double leverage argument suggests that the required return should be based on the source of funds, not the risk of the investment. The double leverage argument, therefore, suggests that the value of the equity in a company would differ based on the investor's source of funds, which is illogical.

Q. Can you provide an example to explain why the double leverage argument is flawed?

A. Yes. Consider the scenario where an investor borrows funds to invest in a stock, such as Apple Inc. ("AAPL"). The expected return to that investor on the AAPL stock is not the cost of the debt that the investor undertook to make the investment, but rather the return afforded all AAPL investors for that same period of investment. In contrast, Ms. Reno's position as applied to this example suggests that the required return to that investor should be a debt return because of the source of the funds, which is irrational, given that this investor would bear all the risk of repayment that is inherent in holding equity in AAPL. Consistent with financial theory, the proper return in this example is based on the risk associated with the use of funds, which is the equity return, not the source of the funds, which is the debt cost.

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[111] *See, e.g.*, Dr. Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, Chapter 20.

Q. Are you aware of academic publications that support the view that the cost of capital should be established for each investment on a stand-alone basis?

A. Yes. Several financial textbooks support this position. For example, in *Principles of Corporate Finance,* Brealey, Myers and Allen note:

> In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is project risk that counts.[112]

Similarly, Modern Corporate Finance indicates:

> Each project has its own required return, reflecting three basic elements: (1) the real or inflation-adjusted risk-free interest rate; (2) an inflation premium approximately equal to the amount of expected inflation; and (3) a premium for risk. The first two cost elements are shared by all projects and reflect the time value of money, whereas the third component varies according to the risks borne by investors in the different projects. For a project to be acceptable to the firm's shareholders, its return must be sufficient to compensate them for all three cost components. This minimum or required return is the project's cost of capital and is sometimes referred to as a hurdle rate. In discussing how to calculate the project's cost of capital, we begin by assuming the firm is all-equity financed and later relax that assumption.
>
> The preceding paragraph bears a crucial message: The cost of capital for a project depends on the riskiness of the assets being financed, not on the identity of the firm undertaking the project. … the risk-required return trade-off is set in the financial marketplace is based on the yields available to investors on other investments with similar risk characteristics. Consequently, the required return on a project (the project's cost of capital) is an opportunity cost, which depends on the alternative market investment that investors must forgo.[113]

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112 Richard A. Brealey, Stewart C. Myers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 8th Ed., 2006, at 234.

113 Alan C. Shapiro, Modern Corporate Finance, Wiley, 1st Ed., 1990, at 276.

Finally, the use of double leverage versus an independent capital structure was studied by Pettway and Jordan (1983)[114] and Lerner (1973).[115] Pettway and Jordan (1983) evaluated the use of these two capital structures in achieving three goals of rate of return regulation, which are that the allowed return must: (1) be sufficiently low as to eliminate monopoly rents or producer's surplus; (2) be sufficiently high to attract capital and guide the allocation of capital resources in a socially desired fashion; and (3) exactly compensate the investors of capital for the risk of their investment in the public utility. The conclusions reached by Pettway and Jordan (1983) were as follows:

> The "double leverage" approach to estimate the allowed rate of return would be incorrect and inappropriate when parents diversify into subsidiaries of unequal risk and/or use parent debt. The use of "double leverage" (1) does not eliminate "monopoly rents" or "producer's surplus" in the regulated operating company, (2) does not provide the proper rate of return to attract capital and to guide the allocation of capital resources in a socially desirable fashion, and (3) does not correctly compensate the investors of capital for the riskiness of their investments in the public utility. In the section, the two approaches are compared in a theoretical framework with tax effects specifically considered. The "independent company" approach is found to be universally correct, whereas the "double leverage" approach is only correct in specific areas. When a public utility holding company has a diversified group of subsidiaries of unequal risk and/or parent debt, a "double leverage" approach which uses the parent's WACC as an estimate of the cost of equity capital of the regulated subsidiary is incorrect and should not be employed. The results of this paper, using both a series of examples and a theoretical framework analysis, reaffirm the "independent company" approach as satisfying the three standards of rate of return regulation. The analysis finds no valid support for the "double leverage" approach; the "independent company" approach is shown to be universally correct.[116]

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[114] Richard H. Pettway and Bradford D. Jordan, "Diversification, Double Leverage, and the Cost of Capital," *The Journal of Financial Research*, Vol VI, No. 4 Winter 1983.

[115] Eugene M. Lerner, "What are the Real Double Leverage Problems," Public Utilities Reports, Inc., June 7, 1973.

[116] *Id.*

Lerner (1973) concluded that the double leverage adjustment should be rejected because it discriminates among classes of security holders, is contrary to the basic principles of financial theory and, if applied, would lead to consequences that are not in the public interest. The author, who was a finance professor at Northwestern University at the time the report was published, noted that it is well-established in financial theory that the cost of equity capital is the risk-adjusted opportunity cost to the investor and that the sources of shareholder funds do not enter into the cost of equity calculation. Further, Lerner (1973) recognized that it is:

> illogical to equate a corporation's cost of equity with its shareholders' sources or costs of funds. The relevant considerations are the alternatives available to the shareholders and the returns and risks associated with those alternatives. Where or how the shareholder obtained the funds used to purchase the shares, or the cost of those funds to the shareholder, are totally irrelevant to the calculation of the cost of equity to the corporation.
>
> This is also true whether the corporation has one or many shareholders and whether the shareholders are individuals or corporations. There is no basis in financial theory for estimating the cost of equity by one procedure for corporations whose shares are owned by individuals and by a different procedure - e.g., using the double leverage adjustment - for corporations whose shares are owned by a holding company. To do so is discriminatory. The mere transfer of ownership of an operating company from the public to a holding company or the reverse should not logically in and of itself result in a change in the operating company's allowable rate of return. Nor should the cost of capital of a parent holding company determine the cost of equity of the subsidiary.[117]

Q. Does financial theory require aligning the Company's equity ratio to the proxy group equity ratio used to determine the ROE?

A. Yes. The Company's proposed equity ratio of 50.63 percent results in greater leverage on average than the proxy group measured using data at both the holding company and

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117 Eugene M. Lerner, "What are the Real Double Leverage Problems," Public Utilities Reports, Inc., June 7, 1973, at 22.

operating subsidiary levels. Thus, the Company's proposed capital structure results in Pike's financial risk being greater than that of the proxy group warranting a common equity cost rate above the proxy group average. It is a fundamental tenet of finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater risk to equity holders and therefore the greater the return required by equity investors.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Exhibit CMW – 1R

Christopher Wall

PRINCIPAL

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With more than ten years of experience as a financial and economic consultant in the energy industry, Mr. Wall specializes in regulatory economics for the electric, natural gas, and water utility sectors.

Mr. Wall has expertise in matters related to rate of return, cost of equity, capital structure, cost of service, and rate design. He has prepared expert testimony related to return on equity and capital structure in over 100 regulatory proceedings for electric, natural gas, and water utility clients across the US.

He has applied his economics, financial modeling, advanced statistics, and econometrics competencies to prepare rate design, rate consolidation, marginal cost, cost of service, valuation, and demand forecast studies for electric and natural gas utilities. These studies have been submitted in utility regulatory proceedings throughout North America.

Mr. Wall has provided expert testimony before regulatory commissions in Arkansas, Massachusetts, New Hampshire, New York and South Dakota on issues that include cost of capital, natural gas demand forecasting, and statistical concepts for return on equity and cost of service.

Prior to joining Brattle, Mr. Wall was an Assistant Vice President at an economic consulting firm.

AREAS OF EXPERTISE

- Electricity Litigation & Regulatory Disputes
- M&A Litigation
- Oil & Gas
- Regulatory Economics, Finance & Rates
- Regulatory Investigations and Enforcement

EDUCATION

- **Northeastern University**
  MA in Economics
- **Saint Peter's College**
  BA in Economics and Mathematics (summa cum laude)

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal (2024-Present)
  Senior Associate (2022-2023)
- **Concentric Energy Advisors, Inc. (2010–2021)**
  Assistant Vice President (2021)
  Senior Project Manager (2019–2020)
  Project Manager (2017–2018)
  Senior Consultant (2015–2016)
  Consultant (2013–2014)
  Assistant Consultant (2011–2012)
  Associate (2010)

SELECTED CONSULTING EXPERIENCE

COST OF CAPITAL

- Provided expert testimony on the cost of capital for electric, natural gas and water utilities.
- Prepared expert testimony and exhibits for return on equity, capital structure, and cost of debt analysis for numerous electric, gas, and water utility clients across the US. This included preparing direct testimony, responding to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting and reviewing post-hearing briefs.

DEMAND FORECASTING & SUPPLY PLANNING

- Filed expert testimony regarding the development of the natural gas demand forecast for a Northeast gas utility.

- Contributed to and worked on demand forecasting projects for multiple Northeast gas utilities:
  - Assisted in the development of natural gas price and effective degree day forecasts.
  - Developed natural gas demand forecasts by customer class using SPSS.
    - Developed models for number of customers and use per customer.
    - Performed checks for model stability, heteroscedasticity, and autocorrelation by performing the Chow, Breusch-Pagan, and Autocorrelation Function/Partial Autocorrelation Function tests.
  - Contributed in the development of the forecasting and supply planning report and supported data requests.

RATEMAKING

- Evaluated rate design restructuring and its impacts on customer bills for Northeast gas and electric utilities.
- Developed marginal cost studies and prepared testimony for Northeast electric and gas utilities.
- Designed rates and prepared testimony for a Northeast electric and gas utility.
- Prepared a cost of service study and designed rates for a Mid-Atlantic municipal gas utility.
- Prepared cost of service studies and designed rates for Midwest electric and gas utilities.
- Evaluated the impact of different rate alternatives and solar generation compensation approaches on solar customers in each rate class for a Midwest municipal electric utility.
- Contributed to the development of a benchmarking study to compare a Canadian natural gas utility's performance with its peers.
- Assisted in the development of a Total Factor Productivity Analysis for a Canadian natural gas utility as part of an Incentive Ratemaking report filed with the Ontario Energy Board.

VALUATION

- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared expert testimony regarding the fair value of the distribution system assets of a Midwest natural gas utility and the fair value of the transmission and distribution system assets of a different Midwest electric utility.

EXPERT TESTIMONY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2014	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Rebuttal Testimony on Statistical Concepts for Return on Equity and Class Cost of Service
Massachusetts Department of Public Utilities				
Berkshire Gas Company	2020	Berkshire Gas Company	D.P.U. 20-139	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-107	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2016	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2014	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas	07/23	EnergyNorth Natural Gas	Docket No. DG 23-067	Return on Equity
Granite State Electric	05/23	Granite State Electric	Docket No. DE 23-039	Return on Equity
New York State Department of Public Service				
Corning Natural Gas Corporation	07/24	Corning Natural Gas Corporation	Case No. 24-G-0447	Return on Equity
Liberty Utilities (New York Water)	05/23	Liberty Utilities (New York Water)	Case No. 23-W-0235	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
South Dakota Public Utilities Commission				
Montana-Dakota Utilities Co.	08/23	Montana-Dakota Utilities Co.	Docket No. NG23-014	Return on Equity

Exhibit CMW – 2R

BUSINESS SEGMENT DATA FOR CHESAPEAKE UTILITIES CORPORATION, NEW JERSEY RESOURCES CORPORATION AND SOUTHWEST GAS HOLDINGS

Chesapeake Utilities Corporation - Operating Income ($000)

Year	Total	Natural Gas Distribution	Electric Distribution	Natural Gas Transmission	Unregulated Energy	Other Businesses and Eliminations	Notes	Percent Reg / Total	Percent Gas Dist. / Total
2024	228,200	104,212	10,221	81,767	31,700	300	[1]	85.98%	45.67%
2023	150,800	54,213	6,771	65,216	24,400	200	[1]	83.69%	35.95%
2022	142,900	52,803	6,501	55,996	27,500	100	[1]	80.69%	36.95%
3 yr. average								**83.45%**	**39.52%**

	Operating Income ($000)	Net Income ($000)						
	Total Regulated Energy	Delmarva Natural Gas Distribution	Florida Natural Gas Distribution	Florida City Gas	FPU Electric Distribution	Eastern Shore	Peninsula Pipeline	Aspire Energy Express
2024	196,200	12,100	26,400	13,500	5,100	25,200	14,700	900
2023	126,200	9,256	23,840	(3,256)	3,727	23,284	12,195	417
2022	115,300	12,930	19,162	-	3,951	23,222	10,372	439

New Jersey Resource Corporation - Operating Income ($000)

Year	Total	Natural Gas Distribution	Clean Energy Ventures	Energy Services	Storage and Transportation	Home Services and Other & Eliminations	Notes	Percent Reg / Total	Percent Gas Dist. / Total
2024	458,104	207,118	58,652	154,279	27,198	10,857	[2]	51.15%	45.21%
2023	407,000	207,528	58,722	113,112	32,425	(4,787)	[2]	58.96%	50.99%
2022	406,475	218,973	66,178	95,639	22,163	3,522	[2]	59.32%	53.87%
3 yr. average								**56.48%**	**50.02%**

Southwest Gas Holdings, Inc. - Operating Income ($000)

Year	Total	Natural Gas Operations	Utility Infrastructure Services	Other	Notes	Percent Reg / Total	Percent Gas Dist. / Total
2024	483,771	412,331	86,783	(15,343)	[2]	85.23%	85.23%

Notes:

[1] Source: CPK - 2024 For 10-K, pgs. 4 and 78; CPK - 2023 For 10-K, pg. 4; and CPK - 2022 For 10-K, pg. 4
[2] Source: NJR - 2024 Form 10-K, pp. 42, 46, 47, 50, and 65
[3] Source: SWX - 2024 Form 10-K, pgs. 34, 35 and 54.

MR. KELLER'S CONSTANT GROWTH DCF -- AS FILED

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	Expected Annualized Dividend	Stock Price - 52 week Low	Stock Price - 52 week High	Stock Price - Spot Price	Expected Dividend Yield - 52 week	Expected Dividend Yield - Spot	S&P Capital IQ Earnings Growth	Zacks Earnings Growth	Value Line Earnings Growth	Average Growth Rate	52 week ROE	Spot Price ROE	Mean ROE
Atmos Energy Corporation	ATO	$3.48	$110.46	$152.65	$141.69	2.65%	2.46%	7.51%	7.00%	7.00%	7.17%	9.82%	9.63%	9.72%
Chesapeake Utilities Corporation	CPK	$2.64	$98.25	$134.20	$120.87	2.27%	2.18%	8.12%	NA	6.50%	7.31%	9.58%	9.49%	9.54%
New Jersey Resources Corporation	NJR	$1.76	$39.44	$51.95	$46.62	3.85%	3.78%	5.60%	NA	5.00%	5.30%	9.15%	9.08%	9.11%
NiSource Inc.	NI	$1.12	$24.80	$38.83	$37.78	3.52%	2.96%	7.80%	7.50%	9.50%	8.27%	11.79%	11.23%	11.51%
Northwest Natural Gas Company	NWN	$1.96	$34.82	$44.25	$39.86	4.96%	4.92%	4.83%	NA	6.50%	5.67%	10.62%	10.58%	10.60%
ONE Gas, Inc.	OGS	$2.68	$57.74	$78.89	$70.17	3.92%	3.82%	2.45%	2.90%	3.50%	2.95%	6.87%	6.77%	6.82%
Spire, Inc.	SR	$3.16	$56.36	$73.64	$69.50	4.86%	4.55%	6.50%	5.80%	4.50%	5.60%	10.46%	10.15%	10.30%
Mean						3.72%	3.52%	6.12%	5.80%	6.07%	6.04%	9.76%	9.56%	9.66%

Notes:
[1] Source: I&E Exhibit No. 2, Schedule 6
[2] Source: I&E Exhibit No. 2, Schedule 6
[3] Source: I&E Exhibit No. 2, Schedule 6
[4] Source: I&E Exhibit No. 2, Schedule 6
[5] Equals [1] / Average ([2], [3])
[6] Equals [1] / [4]
[7] Source: I&E Exhibit No. 2, Schedule 7
[8] Source: I&E Exhibit No. 2, Schedule 7
[9] Source: I&E Exhibit No. 2, Schedule 7
[10] Equals Average ([7], [8], [9])
[11] Equals [5] + [10]
[12] Equals [6] + [10]
[13] Equals Average ([11], [12])

MR. KELLER'S CONSTANT GROWTH DCF -- AS ADJUSTED INCL. SWX

Company	Ticker	[1] Expected Annualized Dividend	[2] Stock Price - 52 week Low	[3] Stock Price - 52 week High	[4] Stock Price - Spot Price	[5] Expected Dividend Yield - 52 week	[6] Expected Dividend Yield - Spot	[7] S&P Capital IQ Earnings Growth	[8] Zacks Earnings Growth	[9] Value Line Earnings Growth	[10] Average Growth Rate	[11] 52 week ROE	[12] Spot Price ROE	[13] Mean ROE
Atmos Energy Corporation	ATO	$3.48	$110.46	$152.65	$141.69	2.65%	2.46%	7.51%	7.00%	7.00%	7.17%	9.82%	9.63%	9.72%
Chesapeake Utilities Corporation	CPK	$2.64	$98.25	$134.20	$120.87	2.27%	2.18%	8.12%	NA	6.50%	7.31%	9.58%	9.49%	9.54%
New Jersey Resources Corporation	NJR	$1.76	$39.44	$51.95	$46.62	3.85%	3.78%	5.60%	NA	5.00%	5.30%	9.15%	9.08%	9.11%
NiSource Inc.	NI	$1.12	$24.80	$38.83	$37.78	3.52%	2.96%	7.80%	7.50%	9.50%	8.27%	11.79%	11.23%	11.51%
Northwest Natural Gas Company	NWN	$1.96	$34.82	$44.25	$39.86	4.96%	4.92%	4.83%	NA	6.50%	5.67%	10.62%	10.58%	10.60%
ONE Gas, Inc.	OGS	$2.68	$57.74	$78.89	$70.17	3.92%	3.82%	2.45%	2.90%	3.50%	2.95%	6.87%	6.77%	6.82%
Southwest Gas Corporation	SWX	$2.52	$57.55	$80.29	$72.19	3.66%	3.49%	10.55%	6.50%	10.00%	9.02%	12.67%	12.51%	12.59%
Spire, Inc.	SR	$3.16	$56.36	$73.64	$69.50	4.86%	4.55%	6.50%	5.80%	4.50%	5.60%	10.46%	10.15%	10.30%
Mean						3.71%	3.52%	6.67%	5.94%	6.56%	6.41%	10.12%	9.93%	10.02%

Notes:
[1] Source: I&E Exhibit No. 2, Schedule 6 and Value Line
[2] Source: I&E Exhibit No. 2, Schedule 6 and S&P Capital IQ Pro.
[3] Source: I&E Exhibit No. 2, Schedule 6 and S&P Capital IQ Pro
[4] Source: I&E Exhibit No. 2, Schedule 6 and Bloomberg Professional
[5] Equals [1] / Average ([2], [3])
[6] Equals [1] / [4]
[7] Source: I&E Exhibit No. 2, Schedule 7 and S&P Capital IQ Pro.
[8] Source: I&E Exhibit No. 2, Schedule 7 and Zacks
[9] Source: I&E Exhibit No. 2, Schedule 7 and Value Line
[10] Equals Average ([7], [8], [9])
[11] Equals [5] + [10]
[12] Equals [6] + [10]
[13] Equals Average ([11], [12])

MR. KELLER'S CONSTANT GROWTH DCF -- AS ADJUSTED INCL. SWX & UPDATED TO MARCH 31, 2025

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	Expected Annualized Dividend	Stock Price - 52 week Low	Stock Price - 52 week High	Stock Price - Spot Price	Expected Dividend Yield - 52 week	Expected Dividend Yield - Spot	S&P Capital IQ Earnings Growth	Zacks Earnings Growth	Value Line Earnings Growth	Average Growth Rate	52 week ROE	Spot Price ROE	Mean ROE
Atmos Energy Corporation	ATO	$3.68	$110.97	$155.26	$154.58	2.76%	2.38%	7.52%	7.10%	6.00%	6.87%	9.64%	9.25%	9.45%
Chesapeake Utilities Corporation	CPK	$2.80	$98.32	$134.20	$128.43	2.41%	2.18%	8.15%	n/a	5.00%	6.58%	8.98%	8.76%	8.87%
New Jersey Resources Corporation	NJR	$1.95	$40.62	$51.95	$49.06	4.21%	3.97%	7.60%	n/a	5.00%	6.30%	10.51%	10.27%	10.39%
NiSource Inc.	NI	$1.20	$26.26	$41.45	$40.09	3.55%	2.99%	8.22%	8.20%	9.50%	8.64%	12.18%	11.63%	11.91%
Northwest Natural Gas Company	NWN	$1.97	$34.82	$44.25	$42.72	4.98%	4.61%	6.50%	n/a	6.50%	6.50%	11.48%	11.11%	11.30%
ONE Gas, Inc.	OGS	$2.72	$58.31	$78.89	$75.59	3.97%	3.60%	3.83%	4.70%	4.00%	4.18%	8.14%	7.77%	7.96%
Southwest Gas Corporation	SWX	$2.48	$64.31	$80.29	$71.80	3.43%	3.45%	12.60%	6.60%	10.00%	9.73%	13.16%	13.19%	13.18%
Spire, Inc.	SR	$3.26	$57.27	$79.11	$78.25	4.78%	4.17%	8.08%	6.50%	4.50%	6.36%	11.14%	10.53%	10.83%
Mean - Excl. SWX						3.81%	3.41%	7.13%	6.63%	5.79%	6.49%	10.30%	9.90%	10.10%
Mean - Incl. SWX						3.76%	3.42%	7.81%	6.62%	6.31%	6.89%	10.66%	10.31%	10.49%

Notes:
[1] Source: Value Line, as of February 21, 2025
[2] Source: S&P Capital IQ Pro as of March 31, 2025
[3] Source: S&P Capital IQ Pro as of March 31, 2025
[4] Source: Bloomberg Professional as of March 31, 2025
[5] Equals [1] / Average ([2], [3])
[6] Equals [1] / [4]
[7] Source: S&P Capital IQ Pro
[8] Source: Zacks
[9] Source: Value Line, as of February 21, 2025
[10] Equals Average ([7], [8], [9])
[11] Equals [5] + [10]
[12] Equals [6] + [10]
[13] Equals Average ([11], [12])

Summary of Projected Market Return based on
Value Line Projected Dividend Yield and Market Appreciation Potential

VL Report Date	Dividend Yield	Appreciation Potential	Growth Rate	DCF Result
1/3/2025	2.10%	45%	9.73%	11.83%
1/10/2025	2.10%	45%	9.73%	11.83%
1/17/2025	2.10%	45%	9.73%	11.83%
1/24/2025	2.10%	45%	9.73%	11.83%
1/31/2025	2.00%	40%	8.78%	10.78%
2/7/2025	2.00%	45%	9.73%	11.73%
2/14/2025	2.10%	45%	9.73%	11.83%
2/21/2025	2.10%	45%	9.73%	11.83%
2/28/2025	2.10%	45%	9.73%	11.83%
3/7/2025	2.10%	50%	10.67%	12.77%
3/14/2025	2.20%	55%	11.58%	13.78%
3/21/2025	2.20%	55%	11.58%	13.78%
3/28/2025	2.20%	55%	11.58%	13.78%
4/4/2025	2.20%	55%	11.58%	13.78%
4/11/2025	2.20%	60%	12.47%	14.67%
4/18/2025	2.50%	75%	15.02%	17.52%
4/25/2025	2.50%	65%	13.34%	15.84%
5/2/2025	2.40%	70%	14.19%	16.59%
Average Jan. 1, 2025-May 2, 2025			11.04%	13.21%

MR. KELLER'S CAPM ASSUMPTIONS

RISK-FREE RATE - 10-YEAR TREASURY YIELD

As Filed [1]		As Updated [2]	
2Q 2025	4.30	3Q 2025	4.30
3Q 2025	4.30	4Q 2025	4.30
4Q 2025	4.30	1Q 2026	4.20
1Q 2026	4.30	2Q 2026	4.20
2Q 2026	4.20	3Q 2026	4.10
2026-2030	4.00	2026-2030	4.00
Average	4.23		4.18

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 1, December 30, 2024, at 2; and Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14.
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2; and Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14.

MR. KELLER'S CAPM ASSUMPTIONS

BETA

		Value Line Beta as of November 2024	Value Line Beta as of February 2025
Atmos Energy Corporation	ATO	0.90	0.90
Chesapeake Utilities Corporation	CPK	0.85	0.85
New Jersey Resources Corporation	NJR	1.00	1.00
NiSource Inc.	NI	0.95	0.95
Northwest Natural Gas Company	NWN	0.85	0.90
ONE Gas, Inc.	OGS	0.85	0.85
Southwest Gas Corporation	SWX	0.95	0.95
Spire, Inc.	SR	0.90	0.90
Average Incl. SWX		0.91	0.91
Average Excl. SWX		0.90	0.91

MR. KELLER'S CAPM ASSUMPTIONS

MARKET RETURN

As Filed: I&E Exhibit No. 2, Schedule 12

	Dividend Yield	Growth Rate	Expected Market Return
Value Line Estimate	2.10%	9.73%	11.83%
S&P Historical Return			12.29%
Average Expected Market Return			12.06%
Value Line Dividend Yield	1/24/2025	2.10%	
Value Line Appreciation Potential	1/24/2025	45%	

As Updated As of March 28, 2025

	Dividend Yield	Growth Rate	Expected Market Return
Value Line Estimate	2.20%	11.58%	13.78%
S&P Historical Return			12.29%
Average Expected Market Return			13.03%
Value Line Dividend Yield	3/28/2025	2.20%	
Value Line Appreciation Potential	3/28/2025	55%	

Comparison of Mr. Keller's CAPM Analysis
Value Line and S&P 500 Market Return

As Filed v. As Adjusted

	Notes	Mr. Keller As-Filed	Incl. SWX	Updated As of March 31, 2025
Risk-Free Rate	[1]	4.23%	4.23%	4.18%
Beta	[2]	0.90	0.91	0.91
Market Return	[3]	12.06%	12.06%	13.03%
Market Risk Premium	[4]	7.83%	7.83%	8.85%
Cost of Equity	[5]	**11.28%**	**11.33%**	**12.26%**
Increase from As-Filed:			***0.05%***	***0.98%***

Notes:

[1] I&E Exhibit No. 2, Schedule 10 (As-Filed); Exhibit CMW-6R (As Updated)

[2] I&E Exhibit No. 2, Schedule 9 (As-Filed); Exhibit CMW-6R (As Adjusted & Updated)

[3] I&E Exhibit No. 2, Schedule 12 (As-Filed); Exhibit CMW-6R (As Updated)

Comparison of Mr. Keller's CAPM Analysis
Kroll MRP

As Filed v. As Adjusted

	Notes	Mr. Keller As-Filed	Incl. SWX	Updated As of March 31, 2025
Risk-Free Rate	[1]	4.55%	4.55%	4.62%
Beta	[2]	0.90	0.91	0.91
Market Risk Premium	[3]	5.00%	5.00%	5.00%
Cost of Equity	[4]	**9.05%**	**9.08%**	**9.18%**
Increase from As-Filed:			***0.03%***	***0.13%***

Notes:
[1] I&E Exhibit No. 2, Schedule 13 (As-Filed); Federal Reserve Bank of St. Louis as of March 31, 2025 (As Updated)
[2] I&E Exhibit No. 2, Schedule 9 (As-Filed); Exhibit CMW-6R (As Adjusted & Updated)
[3] I&E Exhibit No. 2, Schedule 13

MS. RENO - 30-DAY AVG. PRICE - CONSTANT GROWTH DCF - AS FILED

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] S&P Capital IQ Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$145.97	2.38%	2.47%	6.00%	7.44%	7.10%	6.85%	9.31%
Chesapeake Utilities Corporation	CPK	$2.64	$123.83	2.13%	2.20%	5.00%	8.25%	n/a	6.63%	8.83%
New Jersey Resources Corporation	NJR	$1.80	$46.89	3.84%	3.94%	5.00%	5.90%	n/a	5.45%	9.39%
NiSource Inc.	NI	$1.12	$38.83	2.88%	3.01%	9.50%	7.93%	8.20%	8.54%	11.55%
Northwest Natural Gas Company	NWN	$1.96	$40.72	4.81%	4.97%	6.50%	6.50%	n/a	6.50%	11.47%
ONE Gas, Inc.	OGS	$2.68	$71.85	3.73%	3.80%	4.00%	2.63%	4.70%	3.78%	7.58%
Southwest Gas Corporation	SWX	$2.48	$76.31	3.25%	3.40%	10.00%	10.55%	6.60%	9.05%	12.45%
Spire, Inc.	SR	$3.14	$73.16	4.29%	4.41%	4.50%	6.82%	5.80%	5.71%	10.12%
Mean				3.42%	3.53%	6.31%	7.00%	6.48%	6.56%	10.09%
Median				3.49%	3.60%	5.50%	7.13%	6.60%	6.56%	9.76%

Notes:
[1] Source: Schedule MLR-5a
[2] Source: Schedule MLR-5a
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Schedule MLR-5a
[6] Source: Schedule MLR-5a
[7] Source: Schedule MLR-5a
[8] Equals average of [5], [6], [7]
[9] Equals [4] + [8]

MS. RENO - 30-DAY AVG. PRICE - CONSTANT GROWTH DCF - UPDATED TO MARCH 31, 2025

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] S&P Capital IQ Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$149.88	2.32%	2.40%	6.00%	7.52%	7.10%	6.87%	9.28%
Chesapeake Utilities Corporation	CPK	$2.64	$126.56	2.09%	2.15%	5.00%	8.15%	n/a	6.58%	8.73%
New Jersey Resources Corporation	NJR	$1.80	$48.40	3.72%	3.84%	5.00%	7.60%	n/a	6.30%	10.14%
NiSource Inc.	NI	$1.12	$39.42	2.84%	2.96%	9.50%	8.22%	8.20%	8.64%	11.60%
Northwest Natural Gas Company	NWN	$1.96	$41.72	4.70%	4.85%	6.50%	6.50%	n/a	6.50%	11.35%
ONE Gas, Inc.	OGS	$2.68	$74.04	3.62%	3.70%	4.00%	3.83%	4.70%	4.18%	7.87%
Southwest Gas Corporation	SWX	$2.48	$73.88	3.36%	3.52%	10.00%	12.60%	6.60%	9.73%	13.25%
Spire, Inc.	SR	$3.14	$76.43	4.11%	4.24%	4.50%	8.08%	6.50%	6.36%	10.60%
Mean				3.34%	3.46%	6.31%	7.81%	6.62%	6.89%	10.35%
Median				3.49%	3.61%	5.50%	7.84%	6.60%	6.54%	10.37%

Notes:
[1] Source: Schedule MLR-5a
[2] Source: Bloomberg Professional as of March 31, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [4] + [8]

MS. RENO - 90-DAY AVG. PRICE - CONSTANT GROWTH DCF - AS FILED

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] S&P Capital IQ Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Growth Rate	[9] Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$142.58	2.44%	2.52%	6.00%	7.44%	7.10%	6.85%	9.37%
Chesapeake Utilities Corporation	CPK	$2.64	$123.36	2.14%	2.21%	5.00%	8.25%	n/a	6.63%	8.84%
New Jersey Resources Corporation	NJR	$1.80	$47.13	3.82%	3.92%	5.00%	5.90%	n/a	5.45%	9.37%
NiSource Inc.	NI	$1.12	$37.49	2.99%	3.11%	9.50%	7.93%	8.20%	8.54%	11.66%
Northwest Natural Gas Company	NWN	$1.96	$40.50	4.84%	5.00%	6.50%	6.50%	n/a	6.50%	11.50%
ONE Gas, Inc.	OGS	$2.68	$70.97	3.78%	3.85%	4.00%	2.63%	4.70%	3.78%	7.62%
Southwest Gas Corporation	SWX	$2.48	$73.64	3.37%	3.52%	10.00%	10.55%	6.60%	9.05%	12.57%
Spire, Inc.	SR	$3.14	$70.16	4.48%	4.60%	4.50%	6.82%	5.80%	5.71%	10.31%
Mean				3.48%	3.59%	6.31%	7.00%	6.48%	6.56%	10.15%
Median				3.57%	3.68%	5.50%	7.13%	6.60%	6.56%	9.84%

Notes:
[1] Source: Schedule MLR-5c
[2] Source: Schedule MLR-5c
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Schedule MLR-5c
[6] Source: Schedule MLR-5c
[7] Source: Schedule MLR-5c
[8] Equals average of [5], [6], [7]
[9] Equals [4] + [8]

MS. RENO - 90-DAY AVG. PRICE - CONSTANT GROWTH DCF - UPDATED TO MARCH 31, 2025

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] S&P Capital IQ Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Growth Rate	[9] Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$145.39	2.39%	2.48%	6.00%	7.52%	7.10%	6.87%	9.35%
Chesapeake Utilities Corporation	CPK	$2.64	$123.56	2.14%	2.21%	5.00%	8.15%	n/a	6.58%	8.78%
New Jersey Resources Corporation	NJR	$1.80	$47.07	3.82%	3.94%	5.00%	7.60%	n/a	6.30%	10.24%
NiSource Inc.	NI	$1.12	$38.43	2.91%	3.04%	9.50%	8.22%	8.20%	8.64%	11.68%
Northwest Natural Gas Company	NWN	$1.96	$40.62	4.83%	4.98%	6.50%	6.50%	n/a	6.50%	11.48%
ONE Gas, Inc.	OGS	$2.68	$71.72	3.74%	3.81%	4.00%	3.83%	4.70%	4.18%	7.99%
Southwest Gas Corporation	SWX	$2.48	$73.74	3.36%	3.53%	10.00%	12.60%	6.60%	9.73%	13.26%
Spire, Inc.	SR	$3.14	$72.57	4.33%	4.46%	4.50%	8.08%	6.50%	6.36%	10.82%
Mean				3.44%	3.56%	6.31%	7.81%	6.62%	6.89%	10.45%
Median				3.55%	3.67%	5.50%	7.84%	6.60%	6.54%	10.53%

Notes:
[1] Source: Schedule MLR-5c
[2] Source: Bloomberg Professional as of March 31, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [4] + [8]

Comparison of Ms. Reno's CAPM Analysis - Historical MRP

As Filed v. As Adjusted

	Notes	Ms. Reno As-Filed	Historical MRP (1929-2024)	Updated As of March 31, 2025
Risk-Free Rate	[1]	4.70%	4.70%	4.60%
Beta	[2]	0.91	0.91	0.91
Market Risk Premium	[3]	7.17%	7.31%	7.31%
Cost of Equity	[4]	**11.24%**	**11.37%**	**11.27%**
Increase from As-Filed:			***0.13%***	***0.03%***

Notes:

[1] Schedule MLR-7a (As-Filed); Federal Reserve Bank of St. Louis as of March 31, 2025 (As Updated)

[2] Schedule MLR-7a

[3] Schedule MLR-7a (As Filed), *Kroll* , Cost of Capital Navigator (As-Adjusted)

[4] Equals [1] + ([2] x [3])

Comparison of Ms. Reno's CAPM Analysis - Supply Side MRP

As Filed v. As Adjusted

	Notes	Ms. Reno As-Filed	Historical MRP (1929-2024)	Updated As of March 31, 2025
Risk-Free Rate	[1]	4.70%	4.70%	4.60%
Beta	[2]	0.91	0.91	0.91
Market Risk Premium	[3]	6.22%	6.26%	6.26%
Cost of Equity	[4]	**10.37%**	**10.41%**	**10.31%**
Increase from As-Filed:			***0.04%***	***-0.06%***

Notes:
[1] Schedule MLR-7c (As-Filed); Federal Reserve Bank of St. Louis as of March 31, 2025 (As Updated)

[2] Schedule MLR-7c
[3] Schedule MLR-7c (As Filed), *Kroll* , Cost of Capital Navigator (As-Adjusted)
[4] Equals [1] + ([2] x [3])

Comparison of Ms. Reno's CAPM Analysis - *Kroll* MRP

As Filed v. As Adjusted

	Notes	Ms. Reno As-Filed	Corrected Using Spot 20-year Treasury Bond Yield	Updated As of March 31, 2025
Risk-Free Rate	[1]	3.50%	4.55%	4.62%
Beta	[2]	0.91	0.91	0.91
Market Risk Premium	[3]	5.00%	5.00%	5.00%
Cost of Equity	[4]	**8.06%**	**9.11%**	**9.18%**
Increase from As-Filed:			***1.05%***	***1.12%***

Notes:

[1] Schedule MLR-7e (As-Filed); Federal Reserve Bank of St. Louis as of February 28, 2025 (As Corrected), Federal Reserve Bank of St. Louis as of March 31, 2025 (As Updated)
[2] Schedule MLR-7e
[3] *Kroll* , Cost of Capital Navigator
[4] Equals [1] + ([2] x [3])

COMPARISON OF PIKE AND MS. RENO'S PROXY GROUP COMPANIES
REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
					Revenue Stabilization					
						Formula-	Straight Fixed			
			Utility	Test Year	Revenue	Based	Variable	Overall Revenue	Capital Cost	Fuel Adjustment
Company	**Operating Subsidiary**	**State**	**Type**	**Convention**	**Decoupling**	**Rates**	**Rate Design**	**Stabilization**	**Recovery**	**Clause**
Atmos Energy Corp.	Atmos Energy Corp.	Kansas	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Atmos Energy Corp.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Atmos Energy Corp.	Louisiana	Gas	Partially Forecast	Yes	Yes	No	Yes	No	Yes
	Atmos Energy Corp.	Mississippi	Gas	Fully Forecast	Yes	Yes	No	Yes	Yes	Yes
	Atmos Energy Corp.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	No	Yes
	Atmos Energy Corp.	Texas RRC	Gas	Historical	Yes	Yes	No	Yes	Yes	Yes
Chesapeake Utilities Corporation	Chesapeake Utilities Corp.	Delaware	Gas	Partially Forecast	No	No	No	No	Yes	Yes
	Florida Public Utilities Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes
	Florida Public Utilities Co.	Florida	Gas	Fully Forecast	No	No	No	No	Yes	Yes
New Jersey Resources Corporation	New Jersey Natural Gas Co.	New Jersey	Gas	Partially Forecast	Yes	No	No	Yes	Yes	n/a
NiSource Inc.	Northern Indiana Public Service Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Northern Indiana Public Service Co.	Indiana	Gas	Fully Forecast	No	No	No	No	Yes	Yes
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes	n/a
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
	Columbia Gas of Virginia Inc.	Virginia	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes
Northwest Natural Gas Company	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes w/ sharing
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	No	No	Yes
ONE Gas, Inc.	Kansas Gas Service Co.	Kansas	Gas	Historical	Yes	No	No	Yes	Yes	Yes
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Yes	No	No	Yes	No	Yes
	Texas Gas Service Co.	Texas RRC	Gas	Historical	Yes	No	No	Yes	Yes	Yes
Southwest Gas Corporation	Southwest Gas Corp.	Arizona	Gas	Historical	Full	No	No	Yes	Yes	Yes
	Southwest Gas Corp.	California	Gas	Fully Forecast	Full	No	No	Yes	No	Yes
	Southwest Gas Corp.	Nevada	Gas	Historical	Full	No	No	Yes	Yes	Yes
Spire, Inc.	Spire Alabama Inc.	Alabama	Gas	Historical	Yes	Yes	No	Yes	No	Yes
	Spire Gulf Inc.	Alabama	Gas	Historical	Yes	Yes	No	Yes	No	Yes
	Spire Missouri Inc.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes	Yes
Proxy Group Totals			Fully Forecast	11						Yes 25
			Partially Forecast	4				Yes 23	Yes 21	Yes w/ sharing 1
			Historical	13				No 5	No 7	No 0
										n/a 2
			% Forecast	53.57%				% Yes 82.14%	% Yes 75.00%	% Yes 96.43%
Pike Country Light and Power Company [8]		Pennsylvania	Gas	Fully Forecast	Proposed	No	No	Proposed	Yes	Yes

Notes:
[1] Regulatory Research Associates, effective as of March 31, 2025.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit. A designation of "Yes" indicates full or partial decoupling.
[3] S&P Capital IQ Pro, Alternative Regulation
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Yes, if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", or "Environmental compliance".
[7] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[8] Data provided by Pike

SIZE PREMIUM CALCULATION

Ms. Reno's Proxy Group Market Capitalization

Company	Ticker	[1] Market Capitalization ($ billions)
Atmos Energy Corporation	ATO	23.78
Chesapeake Utilities Corporation	CPK	2.90
New Jersey Resources Corporation	NJR	4.83
NiSource	NI	18.62
Northwest Natural Gas Company	NWN	1.67
ONE Gas, Inc.	OGS	4.42
Southwest Gas Corporation	SWX	5.36
Spire, Inc.	SR	4.45
Median		4.64

Pike County Light and Power Company		
Test Year Rate Base ($millions)	[2]	$10.68
Company-Projected Common Equity Ratio	[3]	50.63%
Common Equity ($millions)	[4]	$5.41
Market Capitalization of Proxy Group (median) ($millions)	[5]	$4,640.27

Duff & Phelps Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10		[6] Market Capitalization of Largest Company ($ millions)	[7] Size Premium
1-Largest		3,522,211.14	-0.01%
2		46,949.06	0.33%
3		20,178.36	0.49%
4		9,937.35	0.50%
5		6,181.27	0.74%
6		3,946.15	1.00%
7		2,464.50	1.19%
8		1,417.45	0.88%
9		729.92	1.73%
10-Smallest		304.48	4.47%
Pike County Light and Power Company - Common Equity	[4]	5.41	4.47%
Proxy Group Market Capitalization (median)	[5]	4,640.27	0.74%
Size Premium			3.73%

Notes:
[1] S&P Capital IQ Pro, equals 30-day average as of March 31, 2025
[2] Exhibit G-3, Summary, at 1
[3] Exhibit G-2, Schedule 3
[4] Equals [2] x [3]
[5] Equals median market capitalization of proxy group x 1000
[6]-[7] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2024
[8] Size Premium of the Company less Size Premium of Proxy Group

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	60.20%	60.01%	59.88%	60.03%
Chesapeake Utilities Corporation	CPK	100.00%	100.00%	100.00%	100.00%
New Jersey Resources Corporation	NJR	53.51%	52.09%	51.75%	52.45%
NiSource Inc.	NI	55.44%	54.17%	54.85%	54.82%
Northwest Natural Gas Company	NWN	46.96%	47.72%	44.08%	46.25%
ONE Gas, Inc.	OGS	60.41%	58.24%	61.09%	59.92%
Southwest Gas Corporation	SWX	47.45%	42.33%	45.87%	45.22%
Spire, Inc.	SR	46.19%	47.22%	48.62%	47.34%
Proxy Group					
MEDIAN		54.48%	53.13%	53.30%	53.64%
LOW		46.19%	42.33%	44.08%	45.22%
HIGH		100.00%	100.00%	100.00%	100.00%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	60.20%	60.01%	59.88%	60.03%
Chesapeake Utilities - Delaware Division	CPK	100.00%	100.00%	100.00%	100.00%
Chesapeake Utilities - Maryland Division	CPK	100.00%	100.00%	100.00%	100.00%
Florida Public Utilities - Natural Gas Division	CPK	100.00%	100.00%	100.00%	100.00%
Florida Public Utilities - Electric Division	CPK	100.00%	100.00%	100.00%	100.00%
New Jersey Natural Gas Company	NJR	53.51%	52.09%	51.75%	52.45%
Northern Indiana Public Service Company LLC	NI	59.26%	56.92%	58.59%	58.26%
Columbia Gas of Kentucky, Inc.	NI	53.66%	54.91%	53.87%	54.15%
Columbia Gas of Maryland, Inc.	NI	52.00%	51.96%	55.26%	53.07%
Columbia Gas of Ohio, Inc.	NI	50.50%	50.67%	50.79%	50.65%
Columbia Gas of Pennsylvania, Inc.	NI	55.88%	56.64%	56.05%	56.19%
Columbia Gas of Virginia, Inc.	NI	45.25%	44.25%	44.52%	44.67%
Northwest Natural Gas Company	NWN	46.96%	47.72%	44.08%	46.25%
Kansas Gas Service Company, Inc.	OGS	60.44%	58.37%	61.37%	60.06%
Oklahoma Natural Gas Company	OGS	60.46%	58.26%	60.99%	59.90%
Texas Gas Service Company, Inc.	OGS	60.35%	58.13%	60.98%	59.82%
Southwest Gas Corporation	SWX	47.45%	42.33%	45.87%	45.22%
Spire Alabama Inc.	SR	51.50%	52.01%	54.91%	52.81%
Spire Gulf Inc.	SR	44.44%	41.35%	41.14%	42.31%
Spire Mississippi Inc.	SR	36.88%	38.02%	39.18%	38.03%
Spire Missouri Inc.	SR	44.11%	45.49%	46.20%	45.27%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2023, 2022 and 2021 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	39.80%	39.99%	40.12%	39.97%
Chesapeake Utilities Corporation	CPK	0.00%	0.00%	0.00%	0.00%
New Jersey Resources Corporation	NJR	43.52%	44.41%	42.01%	43.31%
NiSource Inc.	NI	44.56%	45.83%	45.15%	45.18%
Northwest Natural Gas Company	NWN	52.40%	45.46%	44.85%	47.57%
ONE Gas, Inc.	OGS	25.06%	41.76%	38.91%	35.24%
Southwest Gas Corporation	SWX	52.55%	53.97%	49.59%	52.04%
Spire, Inc.	SR	42.51%	39.45%	40.00%	40.65%
Proxy Group					
MEDIAN		43.01%	43.08%	41.06%	41.98%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		52.55%	53.97%	49.59%	52.04%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	39.80%	39.99%	40.12%	39.97%
Chesapeake Utilities - Delaware Division	CPK	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities - Maryland Division	CPK	0.00%	0.00%	0.00%	0.00%
Florida Public Utilities - Natural Gas Division	CPK	0.00%	0.00%	0.00%	0.00%
Florida Public Utilities - Electric Division	CPK	0.00%	0.00%	0.00%	0.00%
New Jersey Natural Gas Company	NJR	43.52%	44.41%	42.01%	43.31%
Northern Indiana Public Service Company LLC	NI	40.74%	43.08%	41.41%	41.74%
Columbia Gas of Kentucky, Inc.	NI	46.34%	45.09%	46.13%	45.85%
Columbia Gas of Maryland, Inc.	NI	48.00%	48.04%	44.74%	46.93%
Columbia Gas of Ohio, Inc.	NI	49.50%	49.33%	49.21%	49.35%
Columbia Gas of Pennsylvania, Inc.	NI	44.12%	43.36%	43.95%	43.81%
Columbia Gas of Virginia, Inc.	NI	54.75%	55.75%	55.48%	55.33%
Northwest Natural Gas Company	NWN	52.40%	45.46%	44.85%	47.57%
Kansas Gas Service Company, Inc.	OGS	39.56%	41.63%	38.63%	39.94%
Oklahoma Natural Gas Company	OGS	39.54%	41.74%	39.01%	40.10%
Texas Gas Service Company, Inc.	OGS	0.00%	41.87%	39.02%	26.96%
Southwest Gas Corporation	SWX	52.55%	53.97%	49.59%	52.04%
Spire Alabama Inc.	SR	41.62%	33.01%	42.04%	38.89%
Spire Gulf Inc.	SR	51.30%	38.77%	42.00%	44.02%
Spire Mississippi Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	42.96%	42.91%	39.42%	41.76%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2023, 2022 and 2021 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities Corporation	CPK	0.00%	0.00%	0.00%	0.00%
New Jersey Resources Corporation	NJR	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
ONE Gas, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%	0.00%
Spire, Inc.	SR	0.00%	0.00%	0.00%	0.00%
Proxy Group					
MEDIAN		0.00%	0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities - Delaware Division	CPK	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities - Maryland Division	CPK	0.00%	0.00%	0.00%	0.00%
Florida Public Utilities - Natural Gas Division	CPK	0.00%	0.00%	0.00%	0.00%
Florida Public Utilities - Electric Division	CPK	0.00%	0.00%	0.00%	0.00%
New Jersey Natural Gas Company	NJR	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2023, 2022 and 2021 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities Corporation	CPK	0.00%	0.00%	0.00%	0.00%
New Jersey Resources Corporation	NJR	2.97%	3.50%	6.25%	4.24%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.64%	6.82%	11.07%	6.18%
ONE Gas, Inc.	OGS	14.53%	0.00%	0.00%	4.84%
Southwest Gas Corporation	SWX	0.00%	3.71%	4.54%	2.75%
Spire, Inc.	SR	11.30%	13.32%	11.38%	12.00%
Proxy Group					
MEDIAN		0.32%	1.75%	2.27%	3.49%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		14.53%	13.32%	11.38%	12.00%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES

Company Name	Ticker	2023	2022	2021	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities - Delaware Division	CPK	0.00%	0.00%	0.00%	0.00%
Chesapeake Utilities - Maryland Division	CPK	0.00%	0.00%	0.00%	0.00%
Florida Public Utilities - Natural Gas Division	CPK	0.00%	0.00%	0.00%	0.00%
Florida Public Utilities - Electric Division	CPK	0.00%	0.00%	0.00%	0.00%
New Jersey Natural Gas Company	NJR	2.97%	3.50%	6.25%	4.24%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.64%	6.82%	11.07%	6.18%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS	0.00%	0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	39.65%	0.00%	0.00%	13.22%
Southwest Gas Corporation	SWX	0.00%	3.71%	4.54%	2.75%
Spire Alabama Inc.	SR	6.88%	14.98%	3.05%	8.30%
Spire Gulf Inc.	SR	4.25%	19.88%	16.86%	13.67%
Spire Mississippi Inc.	SR	63.12%	61.98%	60.82%	61.97%
Spire Missouri Inc.	SR	12.93%	11.60%	14.38%	12.97%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2023, 2022 and 2021 were removed from the analysis.

Market Value of the Capital Structure of Ms. Reno's Proxy Group

Expressed in ($000s)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]
		Debt												Preferred Equity		Common Equity		Market Value			
Company	Ticker	Current Assets	Current Liabilities	Current Long-Term Debt and Leases	Net Working Capital	Short-Term Debt	Short-Term Debt Adj'd for Net Working Capital	Long-Term Debt	Book Value of Total Debt	Market Value of Long-Term Debt	Carrying Amount of Long-Term Debt	Adjustment to Book Value of Long-Term Debt	Market Value of Total Debt	Book Value of Preferred Equity	Market Value of Preferred Equity	Book Value of Common Equity	Market Value of Common Equity	Market Value Of the Firm	Debt Ratio	Preferred Equity Ratio	Common Equity Ratio
Atmos Energy Corporation	ATO	$1,828,127	$1,174,848	$19,888	$673,167	$0	$0	$8,490,245	$8,510,133	$7,337,936	$7,785,000	-$447,064	$8,063,069	$0	$0	$12,780,481	$21,659,594	$29,722,663	27.13%	0.00%	72.87%
Chesapeake Utilities Corporation	CPK	$204,300	$419,400	$27,900	($187,200)	$196,500	$187,200	$1,270,400	$1,485,500	$1,200,000	$1,300,000	-$100,000	$1,385,500	$0	$0	$1,390,200	$2,763,135	$4,148,635	33.40%	0.00%	66.60%
New Jersey Resources Corporation	NJR	$730,704	$818,665	$96,735	$8,774	$337,000	$0	$3,148,056	$3,244,791	$1,085,955	$1,120,000	-$34,045	$3,210,746	$0	$0	$2,312,684	$4,641,258	$7,852,004	40.89%	0.00%	59.11%
NiSource Inc.	NI	$2,080,200	$4,113,400	$1,290,300	($742,900)	$604,600	$604,600	$12,092,700	$13,987,600	$12,505,200	$13,355,700	-$850,500	$13,137,100	$0	$0	$8,684,200	$17,158,794	$30,295,894	43.36%	0.00%	56.64%
Northwest Natural Gas Company	NWN	$557,774	$649,017	$32,627	($58,616)	$170,110	$58,616	$1,755,269	$1,846,512	$1,191,194	$1,365,399	-$174,205	$1,672,307	$0	$0	$1,385,371	$1,584,413	$3,256,720	51.35%	0.00%	48.65%
ONE Gas, Inc.	OGS	$929,881	$1,458,276	$34,170	($494,225)	$914,600	$494,225	$2,396,686	$2,925,081	$2,200,000	$2,400,000	-$200,000	$2,725,081	$0	$0	$3,104,548	$3,940,940	$6,666,021	40.88%	0.00%	59.12%
Southwest Gas Corporation	SWX	$1,464,475	$1,832,097	$58,044	($309,578)	$680,000	$309,578	$4,455,088	$4,822,710	$4,007,622	$4,348,340	-$340,718	$4,481,992	$0	$0	$3,504,187	$5,047,167	$9,529,159	47.03%	0.00%	52.97%
Spire, Inc.	SR	$988,000	$1,991,200	$42,500	($960,700)	$1,158,000	$960,700	$3,697,700	$4,700,900	$3,600,300	$3,746,400	-$146,100	$4,554,800	$242,000	$242,000	$3,066,900	$3,879,567	$8,676,367	52.50%	2.79%	44.71%
MEDIAN																			42.13%	0.00%	57.87%

Notes:
[1] S&P Capital IQ Pro.
[2] S&P Capital IQ Pro.
[3] S&P Capital IQ Pro.
[4] Equals [1] - ([2] -[3])
[5] S&P Capital IQ Pro.
[6] Equals:
  [A] 0 if [4] > 0
  [B] ABS of [4] if [4] < 0 and ABS of [4] < [5]
  [C] [5] if [4] < 0 and ABS of [4] > [5]
[7] S&P Capital IQ Pro.
[8] Equals [3] + [6] + [7]
[9] Company 10-Ks
[10] Company 10-Ks
[11] Equals [9] - [10]
[12] Equals [8] + [11]
[13] S&P Capital IQ Pro.
[14] Equals [13]
[15] S&P Capital IQ Pro.
[16] S&P Capital IQ Pro.
[17] Equals [12] + [14] + [16]
[18] Equals [12] / [17]
[19] Equals [14] / [17]
[20] Equals [16] / [17]

PCLP Statement No. 5-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052357
	:	
Pike County Light & Power Company –	:	
Gas Division	:	
Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052359
	:	
Pike County Light & Power Company –	:	
Electric Division	:	

REBUTTAL TESTIMONY

OF

CHARLENE FAULK

ON BEHALF OF

PIKE COUNTY LIGHT & POWER COMPANY

Dated: May 1, 2025

Q. WHAT IS YOUR NAME AND WHAT IS YOUR POSITION AT PIKE COUNTY LIGHT & POWER COMPANY ("PCLP")?

A. My name is Charlene Faulk and I am the Vice President of Customer Service and Information Technology at PCLP.

Q. ARE YOU AWARE THAT PCLP IS CURRENTLY SEEKING THE PENNSYLVANIA PUBLIC UTILITY COMMISSION'S ("COMMISSION") APPROVAL TO INCREASE ITS GAS AND ELECTRIC RATES?

A. Yes.

Q. DID YOU HAVE THE OPPORTUNITY TO REVIEW THE TESTIMONY OF PCLP'S CUSTOMERS AT THE COMMISSION'S PUBLIC INPUT HEARINGS ON MARCH 18 AND 19, 2025?

A. Yes. I have reviewed those comments in order to address any questions or concerns about PCLP's customer service.

Q. DID ANY CUSTOMERS TESTIFY IN SUPPORT OF THE COMPANY'S SERVICE TO CUSTOMERS?

A. Yes. Various witnesses testified that PCLP provides good customer service and reliable service that has improved since the current owners of PCLP took over and that has improved since PLCP's last rate increase. N.T. 118:21-25 ([PCLP] has done a very good job in system improvements. Reliability has seemed to improve and I think we all appreciate that.); 137:19-23 ("since our last round of rate increases, we have had shorter outages with better response times and better - more timely outage communications. We do appreciate that."); 143:18-21 ("PCLP has done a stellar job in trying to improve the infrastructure that they acquire, and I commend them for that."); 151:16-21("And I want to reiterate, the previous owner of Pike County Light and Power, the difference with the new company ownership is night and day. So I'm happy with the ownership"); 152:19-20 ("We now have new ownership, very happy with that."); 199:21-24 ("And it's just, you know, I have no problem with Pike County Light and Power. I think they're great, their customer services, we've never had any issues with them.").

Q. DID PCLP ADDRESS CLIVE BLEST'S CONCERN ABOUT HIS ABILITY TO BUDGET FOR HIS GAS AND ELECTRIC EXPENSES?

A. Yes, PCLP contacted Mr. Blest and informed him about a significant credit on his account that may be applied to future bills.

Q. SARA VARGAS EXPRESSED CONCERN ABOUT BEING ABLE TO AFFORD THE RATE INCREASES. DID PCLP ADDRESS HER CONCERN?

A. Yes, Ms. Vargas is eligible for budget billing and PCLP left her two voicemails regarding such an arrangement.

Q. DID PCLP ADDRESS JENNIFER LEMIN'S CONCERNS ABOUT BEING ABLE TO AFFORD THE RATE INCREASES?

A. Yes, Ms. Lemin is eligible for budget billing and was provided with information regarding same.

Q. RACHEL HENDRICKS, A MEMBER OF THE MILFORD TOWNSHIP BOARD OF SUPERVISORS, TESTIFIED THAT PCLP COMMITTED TO UPGRADING THE TOWNSHIP'S STREET LIGHT BULBS TO LED BULBS—IS THERE A TIMELINE FOR THE COMPLETION OF THAT WORK?

A. As of March 27, 2025, all of Milford Township's street lights have LED bulbs.

Q. MS. HENDRICKS ALSO QUESTIONED THE ACCURACY OF HER PERSONAL ELECTRICITY BILLS. HAS PCLP INVESTIGATED THAT ASSERTION?

A. Yes, and PCLP has confirmed that all of Ms. Hendricks' electricity bills are free of error.

Q. CHRISTINA PFAEFFLE TESTIFIED REGARDING HER ABILITY TO TIMELY REACH PCLP IN THE EVENT OF ELECTRICITY OUTAGES. HOW CAN CUSTOMERS CONTACT PCLP IN EMERGENCIES OR WHEN THERE IS A POWER OUTAGE?

A. PCLP's office is open Monday through Fridays 8:00 am to 4:30 pm. PCLP has a call center that handles after-hours inquiries. Emergency calls are routed by the call center to a PCLP employee that is on standby. PCLP has employees on standby 24 hours a day, 7 days a week, 365 days a year.

Q. KATHLEEN KETCHAM TESTIFIED THAT SHE IS CONCERNED ABOUT BEING ABLE TO AFFORD THE RATE INCREASES. DID PCLP ADDRESS HER CONCERN?

A. Yes, Ms. Ketcham is eligible for budget billing and PCLP left her two voicemails regarding such an arrangement.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. But I reserve the right to update my testimony as may be necessary.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3052357
	:	
Pike County Light & Power Company (gas)	:	

Pike County Light and Power Company

Statement No. 3-RJ

Rejoinder Testimony of

Nancy Karlovich

Date: May 19, 2025

Q: Have you previously provided testimony in this proceeding?

A: Yes. I provided rebuttal testimony on behalf of Pike County Light & Power Company ("Pike" or the "Company").

Q: What is the purpose of your rejoinder testimony?

A: The purpose of my rejoinder testimony is to adopt the direct testimony of Mr. Verbraak and to update the status of Pike's personnel plans.

Q: Why are you adopting Mr. Verbraak's testimony?

A: Mr. Verbraak was previously the General Manager of Pike, but is no longer with the Company. I am now the General Manager and will sponsor the information in Pike St. No. 3.

Q: Do you have any updates to Pike St. No. 3?

A: Yes. Pages 5-6 of Pike St No. 3 discuss Pike's plan to hire an assistant general manager and an electric systems planner. Pike has decided for now that it will focus on hiring an electric systems planner and a candidate has accepted an offer.

Q: Does this conclude your rejoinder testimony?

A: Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company – Gas	:	

TESTIMONY VERIFICATION OF PAUL M. NORMAND ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY

I, Paul M. Normand, hereby certify that I am Management Consultant and President of Management Applications Consulting, Inc., and that, in such capacity, I have been retained by Pike County Light and Power Company as a witness in the above-captioned matter for the purposes of providing testimony on behalf of Pike County Light and Power Company.

I hereby verify that I have provided the following written Testimony and Exhibits for admission into the record and that these documents were prepared by me and under my supervision:

- PCLP Statement No. 1 – Direct Testimony of Paul M. Normand, including Exhibit Nos. G-6, G-7 and G-8;
- PCLP Statement No. 1-R – Rebuttal Testimony of Paul M. Normand, including Exhibit R - A.

I certify that the facts set forth in the testimony and exhibits are true and correct to the best of my knowledge, information and belief; that if I were asked the questions contained therein today

that my answers would remain the same. I understand that the statements made in my testimony are subject to the penalties at 18 Pa C.S. § 4909 related to the unsworn falsification to authorities.

Dated: 5/22, 2025

Paul M. Normand

Paul M. Normand
Management Consultant and President
Management Applications Consulting, Inc.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company – Gas	:	

TESTIMONY VERIFICATION OF ACCOUNTING PANEL
(CHARLES LENNS AND MATTHEW LENNS)
ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY

We, Charles Lenns and Matthew Lenns, hereby certify that we are the Accounting Panel, and that, in such capacity, we have been retained by Pike County Light and Power Company as expert witnesses in the above-captioned matter for the purposes of providing testimony on behalf of Pike County Light and Power Company.

I hereby verify that I have provided the following written Testimony and Exhibits for admission into the record and that these documents were prepared by me and under my supervision:

- PCLP Statement No. 2 – Direct Testimony of Accounting Panel (Charles Lenns and Matthew Lenns), including Exhibit Nos. G-1, G-2, G-3, EG4, G-5 and Verification of Customer Notice, Notice of Proposed Gas Rate Changes and Public Notice Gas Rates;
- PCLP Statement No. 2-R – Rebuttal Testimony of Accounting Panel (Charles Lenns and Matthew Lenns), including Pike AP-G Update (Schedule Nos. 1-12) and Exhibits AP-1R and AP-2R.

I certify that the facts set forth in the testimony and exhibits are true and correct to the best of my knowledge, information and belief; that if I were asked the questions contained therein today that my answers would remain the same. I understand that the statements made in my testimony are subject to the penalties at 18 Pa C.S. § 4909 related to the unsworn falsification to authorities.

Dated: May 21, 2025

Charles Lenns
Senior Vice President and Chief Financial Officer
Corning Energy Corporation

Dated: May 21, 2025

Matthew Lenns
Controller
Corning Energy Corporation

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company – Gas	:	

TESTIMONY VERIFICATION OF CHARLENE FAULK ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY

I, Charlene Faulk, hereby certify that I am Vice President of Customer Service and Information Technology, and that, in such capacity, I have been retained by Pike County Light and Power Company as an expert witness in the above-captioned matter for the purposes of providing testimony on behalf of Pike County Light and Power Company.

I hereby verify that I have provided the following written Testimony and Exhibits for admission into the record and that these documents were prepared by me and under my supervision:

- PCLP Statement No. 5-R – Rebuttal Testimony of Charlene Faulk.

I certify that the facts set forth in the testimony and exhibits are true and correct to the best of my knowledge, information and belief; that if I were asked the questions contained therein today that my answers would remain the same. I understand that the statements made in my testimony are subject to the penalties at 18 Pa C.S. § 4909 related to the unsworn falsification to authorities.

Dated: May 21, 2025

Charlene M Faulk

Charlene Faulk
Vice President of Customer Service
and Information Technology
Pike County Light & Power Company

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company – Gas Division	:	

TESTIMONY VERIFICATION OF CHRISTOPHER M. WALL
ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY

I, Christopher M. Wall, hereby certify that I am principal of The Brattle Group, and that, in such capacity, I have been retained by Pike County Light and Power Company as an expert witness in the above-captioned matter for the purposes of providing testimony on behalf of Pike County Light and Power Company.

I hereby verify that I have provided the following written Testimony and Exhibits for admission into the record and that these documents were prepared by me and under my supervision:

- PCLP Statement No. 4-R – Rebuttal Testimony of Christopher M. Wall, Principal, The Brattle Group, including Exhibit Nos. CMW-1R, CMW-2R, CMW-3R, CMW-4R, CMW-5R, CMW-6R, CMW-7R, CMW-8R, CMW-9R, CMW-10R, CMW-11R and CMW-12R

I certify that the facts set forth in the testimony and exhibits are true and correct to the best of my knowledge, information and belief; that if I were asked the questions contained therein today

that my answers would remain the same. I understand that the statements made in my testimony are subject to the penalties at 18 Pa C.S. § 4909 related to the unsworn falsification to authorities.

Dated: May 21, 2025

Christopher M. Wall
Principal
The Brattle Group

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3052357
v.	:	
	:	
Pike County Light & Power Company – Gas	:	

TESTIMONY VERIFICATION OF NANCY KARLOVICH
ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY

I, Nancy Karlovich, hereby certify that I am General Manager, and that, in such capacity, I have been retained by Pike County Light and Power Company as an expert witness in the above-captioned matter for the purposes of providing testimony on behalf of Pike County Light and Power Company.

I hereby verify that I have provided the following written Testimony and Exhibits for admission into the record and that these documents were prepared by me and under my supervision:

- PCLP Statement No. 3 – Direct Testimony of Ed Verbraak (adopted by Nancy Karlovich);
- PCLP Statement No. 3-R – Rebuttal Testimony of Nancy Karlovich;
- PCLP Statement No. 3-RJ – Rejoinder Testimony of Nancy Karlovich.

I certify that the facts set forth in the testimony and exhibits are true and correct to the best of my knowledge, information and belief; that if I were asked the questions contained therein today

that my answers would remain the same. I understand that the statements made in my testimony are subject to the penalties at 18 Pa C.S. § 4909 related to the unsworn falsification to authorities.

Dated: 5/22/2025

Nancy Karlovich

Nancy Karlovich
General Manager
Pike County Light and Power Company

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true and correct copy of the foregoing document upon the parties, listed below, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a party).

VIA ELECTRONIC MAIL ONLY

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/s/ Whitney E. Snyder
Whitney E. Snyder
Erich W. Struble

DATED: June 6, 2025