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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 - Electric; Docket No. R-2024-3052359; **PCLP Pre-Served Testimony, Exhibits and Verifications**

Dear Secretary Homsher:

Enclosed for filing please find Pike County Light & Power Company – Electric 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:

<u>Direct Testimony</u>

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

<u>Rebuttal Testimony</u>

5. PCLP Statement No. 1-R – Rebuttal Testimony of Paul M. Normand.
6. PCLP Statement No. 2-R – Rebuttal Testimony of Accounting Panel (Charles Lenns and Matthew Lenns), including Pike AP-E Update (Schedule Nos. 1-12) and Exhibit AP-1R.

7. 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 and CMW-8R.

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

Rejoinder

9. 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.

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-2024-3052359 |
| | : | |
| Pike County Light & Power Company (electric) | : | |

# PIKE COUNTY LIGHT & POWER COMPANY(Electric)

# Statement No. 1

# Direct Testimony of Paul M. Normand

# Electric Embedded Cost of Service (Exhibit E-6)

# Electric Cost of Service Proposed Revenues (Exhibit E-7)

# Electric Rate Design Recommendations (Exhibits E-8)

MANAGEMENT APPLICATIONS CONSULTING, INC.
1103 Rocky Drive, Suite 201
Reading, PA 19609-1157

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**www.manapp.com**

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

| | |
|---|---|
| **EXHIBIT E-7** | Electric Embedded Cost of Service Summary Results<br>– Proposed at Equalized ROR, Based on 12 Months Ended 09/30/2025 |
| **EXHIBIT E-8** | Electric Rate Design and Bill Impact Analysis |

**INTRODUCTION**

**Q. Please state your 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. My position is management consultant and president of the firm.

**Q. Please state your qualifications.**

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

**SCOPE OF TESTIMONY**

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

A. I am sponsoring the following three exhibits:

- Exhibit E-6, the Electric Embedded Cost of Service Study
- Exhibit E-7, the Electric Cost of Service Summary at Proposed Rates
- Exhibit E-8, the Electric 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") Electric Embedded Cost of Service ("COS") Study as of September 30, 2024;
2. The Company's Electric 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 E-6.**

A. Exhibit E-6 consists of six schedules, Schedule PMN-1-E through PMN-6-E. Schedule PMN-1-E contains the qualifications of Paul M. Normand. Schedule PMN-2-E 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-E contains the class embedded cost of service study summary at existing, claimed (uniform) and proposed revenue rate of return. Schedule PMN-4-E presents the complete detailed output of the test period class embedded cost of service study as summarized in Schedule PMN-2-E. Schedule PMN-5-E, pages 1 and 2 presents the Unbundled Costs Summary of Results of Schedule PMN-3-E by the major COS cost component categories based on the present revenue level test period ended September 30, 2024. Schedule PMN-5-E, pages 3 and 4 present the same information at the proposed equalized rate of return revenue levels using the future test period (rate year) September 30, 2025. Schedule PMN-6-E provides a description of the allocation factors used in the embedded cost of service study (Schedule PMN-4-E). Exhibit E-7 includes the cost of service summary of results at the proposed test period ended September 30, 2025. Exhibit E-8 presents the electric rate design calculations for the proposed rates and associated revenue targets. Also included in Exhibit E-8 are the 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 services and customer classes depending upon the nature of their demands, delivery voltage on 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 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 electric 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 cost of service study is a distribution function study and includes other power production costs that are recovered in the distribution base rates. All costs, with the exception of the other power production costs, have been classified as either demand-related or customer-related costs in this study.

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

**Q. Please summarize your cost of service study.**

A. Schedule PMN-3-E shows a summary of class revenue requirements at existing rates, at an overall uniform 8.37% targeted (claimed) rate of return identified by the Company, and at proposed revenue levels. A second analysis, Schedule PMN-5-E, 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 existing (page 2, line 37) and uniform (page 4, line 37) ROR schedules. The specific customer costs included in the total monthly customer costs are shown in detail on lines 38 through 45 of pages 2 and 4 of Schedule PMN-5-E.

**Description of Cost of Service (COS) Model**

**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 Electric 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 14 in Schedule PMN-4-E and is repeated in the same sequence as a percentage of the total value for each allocator at the end of the study beginning on page 19.

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 |
|---|---|
| SC1 | Residential |
| SC1 | Residential Space/Water Heating |
| SC2-S | Small Commercial & Industrial Secondary |
| SC2-P | Small Commercial & Industrial Primary |
| SC3 | Municipal Street Lighting |
| SC4 | Private Lighting |

**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-E, pages 14 through 26. Pages 14 through 18 present the total actual Company values while the remaining pages 19 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 E-6, Schedule PMN-6-E.

**Rate Base Allocation**

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

A. Rate base allocation is shown on pages 2 through 4 of Schedule PMN-4-E. Distribution plant represents investment in facilities to deliver electricity to the customer meter.

**Q. Please describe the allocation of Distribution Plant Accounts 360 through 368 to customer classes.**

A. The distribution plant accounts were functionalized as High Tension (primary) and Low Tension (secondary). The Low Tension costs were subdivided into demand and customer components using a "Minimum Size" minimum system methodology.

The High Tension (primary) function includes the fixed costs for the distribution substations and primary feeders that provide the source of supply from the higher voltage grid to the lower voltage substations and to the primary voltage high tension customers.

The Low Tension (secondary) function includes fixed costs associated with overhead (OH) and underground (UG) secondary line transformers and the overhead and underground lines. The Low Tension demand component includes the transformers and the evaluated costs of that portion of the secondary system for OH and UG Lines required supplying the connected load, above a base of a zero load.

The Low Tension secondary customer component includes the fixed costs that are considered to be joint customer costs as distinguished from direct customer costs, since they represent the estimated costs of the minimum-size jointly-used network of distribution lines needed to serve customers under the existing conditions of customer density and geographical dispersion, on the assumption of little or no use of the service by any customer. Expressed in another manner, the customer component is the cost of the smallest secondary system theoretically needed to physically connect all of the existing service points to line transformers, if the system was not required to supply any load.

The cost of service study utilized the same primary and secondary line separation and minimum system distribution factors for Accounts 360 through 368 as was used in the 2013 General Base Rate Increase Filing.  The factors used in the cost of service study are as follows:

**DISTRIBUTION FACTORS**

| | High Tension | Low Tension | | |
|---|---|---|---|---|
| | Primary | Secondary | | |
| **Account** | **Percent** | **Percent** | **Percent** | **Total** |
| 360 | 100.00% | | | 100.00% |
| 361 | 100.00% | | | 100.00% |
| 361 | 100.00% | | | 100.00% |
| 362 | 100.00% | | | 100.00% |
| 364 | 65.50% | 4.05% | 30.45% | 100.00% |
| 365 | 65.50% | 4.05% | 30.45% | 100.00% |
| 366 | 2.72% | 22.17% | 75.12% | 100.00% |
| 367 | 2.72% | 22.17% | 75.12% | 100.00% |
| 368 | | 23.70% | 76.30% | 100.00% |
| **Classification** | Demand | Demand | Customer | |

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

A. Customer-related plant items were allocated using the "**CDIST**" or "**CUST"** prefixed allocators for services, meters, and other such customer-related items. A complete list of these factors has been provided on Exhibit E-6, Schedule PMN-4-E, page 14 of the cost of service study.

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

A. General plant was allocated on an internally generated labor allocation factor (**LABOR**) based on labor expensed in the test year. 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-E, page 12.

**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-E, page 4. Additions to net plant included allowance for working capital which includes Cash Working Capital, Materials and Supplies and Prepayments. The deductions from net plant include customer deposits, deferred credits (net of tax), and accumulated 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 deferred debits were allocated on **TOTPLT**. Revenue related prepayments of gross earnings, PA Corp Net Income, and PA PUC assessment were allocated on claimed revenues (**CLAIMREV)**. Cash working capital was allocated on O&M expense excluding purchased power (**OMXPP**).

**Operating Revenue Allocation**

**Q. How were operating revenues assigned?**

A. Operating revenues (Schedule PMN-4-E, page 5) are based on the Company's books and records by customer class allocated on the most appropriate allocation factor. Sales of Electric revenue were directly assigned to each class. Other operating revenue account 450, late payment charges, was allocated on the basis of the late payment charges incurred for each rate class. Rent from electric property was allocated on plant account 364 – poles, towers & Fixtures (**PLT_364**) and other electric revenues were allocated on revenues (**CLAIMREV**).

**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.

## Cost of Service Study Results

**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. Schedule PMN-2-E shows 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-E | |
|---|---|---|
| | ROR (%) | ROR Index |
| Total Company | 6.30 | 1.00 |
| SC1 Residential | 3.58 | 0.57 |
| SC1 Residential Space/Water Heating | 5.97 | 0.95 |
| SC2-S Small Commercial & Industrial Secondary | 9.98 | 1.58 |
| SC2-P Large Commercial & Industrial Primary | 9.90 | 1.57 |
| SC3 Municipal Street Lighting | 2.71 | 0.43 |
| SC4 Private Street Lighting | 0.47 | 0.07 |

**Q. Have you 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 6.30%, which classes are considered to be deficient and which classes are surplus?**

A. The customer class ROR inequities shown in Schedules PMN-2-E and PMN-3-E indicate that the SC2-S Small Commercial and Industrial Secondary and the SC2-P Large Commercial and Industrial Primary customer classes are surplus and are subsidizing the

SC1 Residential and Residential Space/Water Heating, the SC4 Municipal Lighting, the and SC4 Private Lighting customer classes which are deficient.

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

A. Yes, I have. Schedule Exhibit E-6, Schedule PMN-5-E provides 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-E, pages 3 and 4, at a uniform ROR level for each customer class. These results indicate the proper level of customer-related costs which should be recovered on a monthly basis which we used as a guide in establishing the proposed rate designs presented in Exhibit E-8. 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.

## 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 E-6, Schedule PMN-5-E, 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 E-8, pages 1-5 of 28.

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

A. Our rate design efforts were performed in three steps. First, we determined the total costs incurred to serve each customer class using the future test year September 30, 2025, Exhibit E-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 E-6, Schedule PMN-3-E. Finally, we performed the proposed 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-E and PMN-3-E)
3. Cost of Service at a Uniform Target Rate of Return (Exhibit E-7 and PMN-3-E)
4. Use of unbundled costs results presented in Schedule PMN-5-E
5. Initial Target Class Revenue Increases using Rate Year Revenue Requirement

6. Set initial class target increases (cap) using a class base revenue target limit of 110% of Pike's overall increase to mitigate level of increase, and
7. Reduce existing class subsidies.

**Q. Have you limited your proposed increase to a maximum amount for any customer classes?**

A. Yes, we have. Exhibit E-8, pages 1 and 2 of 28, shows that we have limited the increase to a target maximum of 110% of the overall system base increase of 29.1% or 32.0%. As can be noted from Exhibit E-8, page 1, the proposed maximum revenue target limits are only applied to Residential and Street Lighting classes which are significantly underpriced and will obviously need several more increases to achieve a more cost-based price through future Pike rate increases.

We should also note that this target maximum increase level is on base rate revenue levels and the final percent increase is less as can be seen on the bill comparisons presented in Exhibit E-8 after including fuel cost. An overall class summary of each class's increase to total class revenues is also presented on page 1, lines 32 through 34 of Schedule PMN-3-E.

<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 page 6 of 28 of Exhibit E-8. I have shown the total charges under present and proposed rates for a variety of usage levels for the Service

Classifications, pages 11 through 20. The last line of page 11 shows the monthly delivery costs for a SC1 Residential customer using 674 kWh would increase from $75.03 to $90.55, or 20.7%. The total monthly bill including supply costs for these customers would increase 11.6% as shown on Exhibit E-8, pages 11 and 27.

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

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

# Schedule PMN-1-E

# Qualifications
# of
# Paul M. Normand

## Qualification of Paul M. Normand

**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**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 Electricity - Base | SCH REV, LN 4 | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| SUM | 7 | Other Operating Revenue | SCH REV, LN 12 | (26,742) | (2,499) | (3,643) | 1,145 | (18,177) | (4,324) | (1,223) | (520) |
| SUM | 8 | TOTAL OPERATING REVENUE | | 7,334,342 | 3,614,220 | 2,947,972 | 666,249 | 3,022,725 | 536,984 | 111,405 | 49,008 |
| SUM | 9 | | | | | | | | | | |
| SUM | 10 | **OPERATING EXPENSES** | | | | | | | | | |
| SUM | 11 | Other Power Supply Exp | SCH EOM, LN 8 | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| SUM | 12 | Operation and Maintenance Expense | SCH EOM, LN 89 | 3,230,840 | 2,072,733 | 1,750,096 | 322,637 | 924,804 | 148,300 | 47,890 | 37,112 |
| SUM | 13 | Depreciation and Amortization Expense | SCH EDA, LN 26 | 1,096,950 | 577,368 | 482,628 | 94,740 | 399,595 | 57,999 | 42,767 | 19,222 |
| SUM | 14 | Taxes Other Than Income Taxes | SCH TXO, LN 15 | 242,261 | 150,180 | 126,841 | 23,339 | 72,484 | 11,554 | 4,850 | 3,193 |
| SUM | 15 | State Income Taxes | SCH TXI, LN 27 | (33,874) | (65,300) | (61,183) | (4,118) | 36,219 | 5,751 | (6,290) | (4,255) |
| SUM | 16 | Federal Income Taxes | SCH TXI, LN 42 | (81,918) | (157,915) | (147,958) | (9,957) | 87,588 | 13,908 | (15,210) | (10,289) |
| SUM | 17 | TOTAL OPERATING EXPENSES | | 5,189,127 | 2,885,801 | 2,400,449 | 485,353 | 1,835,772 | 344,384 | 76,863 | 46,307 |
| SUM | 18 | | | | | | | | | | |
| SUM | 19 | Operating Income Before Taxes | | 2,029,423 | 505,203 | 338,382 | 166,821 | 1,310,760 | 212,260 | 13,042 | (11,843) |
| SUM | 20 | | | | | | | | | | |
| SUM | 21 | **OPERATING INCOME (RETURN)** | | 2,145,215 | 728,419 | 547,523 | 180,896 | 1,186,953 | 192,600 | 34,542 | 2,701 |
| SUM | 22 | | | | | | | | | | |
| SUM | 23 | **DEVELOPMENT OF RATE BASE** | | | | | | | | | |
| SUM | 24 | Electric Utility Plant in Service | SCH RBP, LN 19 | 38,284,336 | 20,645,745 | 17,251,934 | 3,393,811 | 13,457,674 | 2,166,876 | 1,385,252 | 628,788 |
| SUM | 25 | Less: Electric Utility Accumulated Depreciation | SCH RBP, LN 46 | 5,313,834 | 3,012,920 | 2,530,340 | 482,580 | 1,814,242 | 273,593 | 140,828 | 72,251 |
| SUM | 26 | Plus: Rate Base Additions | SCH RBO, LN 13 | 2,923,459 | 1,682,388 | 1,411,628 | 270,759 | 960,085 | 154,258 | 83,790 | 42,938 |
| SUM | 27 | Less: Rate Base Deductions | SCH RBO, LN 19 | 1,866,500 | 972,917 | 819,420 | 153,497 | 710,940 | 101,938 | 55,509 | 25,196 |
| SUM | 28 | **TOTAL RATE BASE** | SCH RBO, LN 22 | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| SUM | 29 | | | | | | | | | | |
| SUM | 30 | **RATE OF RETURN (PRESENT)** | | 6.30% | 3.97% | 3.58% | 5.97% | 9.98% | 9.90% | 2.71% | 0.47% |
| SUM | 31 | **DISTRIBUTION INDEX RATE OF RETURN (PRESENT)** | | 1.00 | 0.63 | 0.57 | 0.95 | 1.58 | 1.57 | 0.43 | 0.07 |
| 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**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| RRW | 6 | Net Operating Income (Present Rates) | | 2,145,215 | 728,419 | 547,523 | 180,896 | 1,186,953 | 192,600 | 34,542 | 2,701 |
| RRW | 7 | Rate of Return @ Present Rates | | 6.30% | 3.97% | 3.58% | 5.97% | 9.98% | 9.90% | 2.71% | 0.47% |
| RRW | 8 | Relative Rate of Return | | 1.00 | 0.63 | 0.57 | 0.95 | 1.58 | 1.57 | 0.43 | 0.07 |
| RRW | 9 | Sales Revenue at Present Rates | | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| RRW | 10 | Revenue Present Rates $/kWh | | $0.0872 | $0.1020 | $0.1028 | $0.0986 | $0.0840 | $0.0440 | $0.3433 | $0.3257 |
| RRW | 11 | Revenue Required - $/Month/Customer | | $114.09 | $69.61 | $66.07 | $91.27 | $266.75 | $4,666.45 | $782.14 | $54.97 |
| RRW | 12 | Revenue Present Rates $/kW | | $59.36 | $0.00 | $0.00 | $0.00 | $30.57 | $22.08 | $0.00 | $0.00 |
| RRW | 13 | | | | | | | | | | |
| RRW | 14 | CLAIMED RATE OF RETURN | | | | | | | | | |
| RRW | 15 | -------------------------------------------------------------------------------- | | | | | | | | | |
| RRW | 16 | Claimed Rate of Return | | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% |
| RRW | 17 | Return Required for Claimed Rate of Return | | 3,267,197 | 1,756,851 | 1,466,687 | 290,165 | 1,145,532 | 186,982 | 122,654 | 55,177 |
| RRW | 18 | Sales Revenue Required @ Claimed ROR | | 9,504,985 | 5,407,411 | 4,537,090 | 870,321 | 3,145,608 | 561,282 | 256,448 | 134,236 |
| RRW | 19 | Sales Revenue Deficiency | | 2,143,900 | 1,790,692 | 1,585,475 | 205,217 | 104,706 | 19,974 | 143,820 | 84,708 |
| RRW | 20 | Percent Increase Required | | 29.12% | 49.51% | 53.72% | 30.85% | 3.44% | 3.69% | 127.70% | 171.03% |
| RRW | 21 | Annual Booked kWh Sales | | 84,427,347 | 35,464,237 | 28,720,125 | 6,744,112 | 36,193,179 | 12,289,759 | 328,097 | 152,075 |
| RRW | 22 | Sales Revenue Required $/kWh | | $0.1126 | $0.1525 | $0.1580 | $0.1290 | $0.0869 | $0.0457 | $0.7816 | $0.8827 |
| RRW | 23 | Revenue Deficiency $/kWh | | $0.0254 | $0.0505 | $0.0552 | $0.0304 | $0.0029 | $0.0016 | $0.4383 | $0.5570 |
| RRW | 24 | | | | | | | | | | |
| RRW | 25 | | | | | | | | | | |
| RRW | 26 | PROPOSED RATE OF RETURN | | | | | | | | | |
| RRW | 27 | -------------------------------------------------------------------------------- | | | | | | | | | |
| RRW | 28 | Rate Base at Future Test Year 09/30/2025 | | 39,033,500 | 20,989,261 | 17,522,639 | 3,466,622 | 13,685,770 | 2,233,894 | 1,465,364 | 659,210 |
| RRW | 29 | Proposed Base Electric Sales Revenues | | 9,504,979 | 4,775,423 | 3,896,239 | 879,184 | 3,833,137 | 682,313 | 148,711 | 65,395 |
| RRW | 30 | Base Sales Revenue Deficiency | | 2,143,894 | 1,158,704 | 944,624 | 214,080 | 792,235 | 141,005 | 36,083 | 15,867 |
| RRW | 31 | Return Required for Proposed Revenue | | 3,267,191 | 1,124,864 | 825,836 | 299,028 | 1,833,060 | 308,013 | 14,917 | (13,664) |
| RRW | 32 | Percent Increase Required at Proposed Rates | | 29.12% | 32.04% | 32.00% | 32.19% | 26.05% | 26.05% | 32.04% | 32.04% |
| RRW | 33 | Proposed Rate of Return | | 8.37% | 5.36% | 4.71% | 8.63% | 13.39% | 13.79% | 1.02% | -2.07% |
| RRW | 34 | Relative Rate of Return | | 1.00 | 0.64 | 0.56 | 1.03 | 1.60 | 1.65 | 0.12 | -0.25 |
| RRW | 35 | | | | | | | | | | |
| RRW | 36 | | | | | | | | | | |
| RRW | 37 | | | | | | | | | | |
| RRW | 38 | | | | | | | | | | |
| RRW | 39 | | | | | | | | | | |
| RRW | 40 | | | | | | | | | | |
| RRW | 41 | | | | | | | | | | |
| RRW | 42 | | | | | | | | | | |
| RRW | 43 | | | | | | | | | | |
| RRW | 44 | | | | | | | | | | |
| RRW | 45 | | | | | | | | | | |
| RRW | 46 | | | | | | | | | | |
| RRW | 47 | | | | | | | | | | |
| RRW | 48 | | | | | | | | | | |
| RRW | 49 | | | | | | | | | | |
| RRW | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 Electricity - Base | SCH REV, LN 4 | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| SUM | 7 | Other Operating Revenue | SCH REV, LN 12 | (26,742) | (2,499) | (3,643) | 1,145 | (18,177) | (4,324) | (1,223) | (520) |
| SUM | 8 | TOTAL OPERATING REVENUE | | 7,334,342 | 3,614,220 | 2,947,972 | 666,249 | 3,022,725 | 536,984 | 111,405 | 49,008 |
| SUM | 9 | | | | | | | | | | |
| SUM | 10 | **OPERATING EXPENSES** | | | | | | | | | |
| SUM | 11 | Other Power Supply Exp | SCH EOM, LN 8 | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| SUM | 12 | Operation and Maintenance Expense | SCH EOM, LN 89 | 3,230,840 | 2,072,733 | 1,750,096 | 322,637 | 924,804 | 148,300 | 47,890 | 37,112 |
| SUM | 13 | Depreciation and Amortization Expense | SCH EDA, LN 26 | 1,096,950 | 577,368 | 482,628 | 94,740 | 399,595 | 57,999 | 42,767 | 19,222 |
| SUM | 14 | Taxes Other Than Income Taxes | SCH TXO, LN 15 | 242,261 | 150,180 | 126,841 | 23,339 | 72,484 | 11,554 | 4,850 | 3,193 |
| SUM | 15 | State Income Taxes | SCH TXI, LN 27 | (33,874) | (65,300) | (61,183) | (4,118) | 36,219 | 5,751 | (6,290) | (4,255) |
| SUM | 16 | Federal Income Taxes | SCH TXI, LN 42 | (81,918) | (157,915) | (147,958) | (9,957) | 87,588 | 13,908 | (15,210) | (10,289) |
| SUM | 17 | TOTAL OPERATING EXPENSES | | 5,189,127 | 2,885,801 | 2,400,449 | 485,353 | 1,835,772 | 344,384 | 76,863 | 46,307 |
| SUM | 18 | | | | | | | | | | |
| SUM | 19 | Operating Income Before Taxes | | 2,029,423 | 505,203 | 338,382 | 166,821 | 1,310,760 | 212,260 | 13,042 | (11,843) |
| SUM | 20 | | | | | | | | | | |
| SUM | 21 | **OPERATING INCOME (RETURN)** | | 2,145,215 | 728,419 | 547,523 | 180,896 | 1,186,953 | 192,600 | 34,542 | 2,701 |
| SUM | 22 | | | | | | | | | | |
| SUM | 23 | **DEVELOPMENT OF RATE BASE** | | | | | | | | | |
| SUM | 24 | Electric Utility Plant in Service | SCH RBP, LN 19 | 38,284,336 | 20,645,745 | 17,251,934 | 3,393,811 | 13,457,674 | 2,166,876 | 1,385,252 | 628,788 |
| SUM | 25 | Less: Electric Utility Accumulated Depreciation | SCH RBP, LN 46 | 5,313,834 | 3,012,920 | 2,530,340 | 482,580 | 1,814,242 | 273,593 | 140,828 | 72,251 |
| SUM | 26 | Plus: Rate Base Additions | SCH RBO, LN 13 | 2,923,459 | 1,682,388 | 1,411,628 | 270,759 | 960,085 | 154,258 | 83,790 | 42,938 |
| SUM | 27 | Less: Rate Base Deductions | SCH RBO, LN 19 | 1,866,500 | 972,917 | 819,420 | 153,497 | 710,940 | 101,938 | 55,509 | 25,196 |
| SUM | 28 | **TOTAL RATE BASE** | SCH RBO, LN 22 | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| SUM | 29 | | | | | | | | | | |
| SUM | 30 | **RATE OF RETURN (PRESENT)** | | 6.30% | 3.97% | 3.58% | 5.97% | 9.98% | 9.90% | 2.71% | 0.47% |
| SUM | 31 | **DISTRIBUTION INDEX RATE OF RETURN (PRESENT)** | | 1.00 | 0.63 | 0.57 | 0.95 | 1.58 | 1.57 | 0.43 | 0.07 |
| 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**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| RBP | 1 | **DEVELOPMENT OF RATE BASE** | | | | | | | | | |
| RBP | 2 | **ELECTRIC PLANT IN SERVICE** | | | | | | | | | |
| RBP | 3 | INTANGIBLE PLANT | | | | | | | | | |
| RBP | 4 | 301 - Organization | DISTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 5 | 303-Miscellaneous Intangible Plant 85% | DISTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 6 | TOTAL INTANGIBLE PLANT | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 7 | | | | | | | | | | |
| RBP | 8 | DISTRIBUTION PLANT | | | | | | | | | |
| RBP | 9 | 360-Land & Land Rights - HT | DDISPHT | 1,090,953 | 458,581 | 371,374 | 87,207 | 496,516 | 129,450 | 4,377 | 2,029 |
| RBP | 10 | 361-Structures & Improvements - HT | DDISPHT | (2,832) | (1,190) | (964) | (226) | (1,289) | (336) | (11) | (5) |
| RBP | 11 | 362-Station Equipment - HT | DDISPHT | 1,272,591 | 534,932 | 433,206 | 101,726 | 579,183 | 151,003 | 5,106 | 2,367 |
| RBP | 12 | 364-Poles,Towers & Fixtures | | | | | | | | | |
| RBP | 13 | Primary HT | DDISPHT | 8,539,245 | 3,589,461 | 2,906,866 | 682,596 | 3,886,391 | 1,013,248 | 34,264 | 15,881 |
| RBP | 14 | Secondary Demand | DDISTSOL | 527,961 | 276,338 | 223,788 | 52,550 | 248,460 | 0 | 2,161 | 1,002 |
| RBP | 15 | Secondary Customer | CDISTSOLC | 3,970,480 | 2,959,582 | 2,544,422 | 415,160 | 644,371 | 0 | 256,956 | 109,571 |
| RBP | 16 | Total Account 364 | | 13,037,686 | 6,825,381 | 5,675,076 | 1,150,305 | 4,779,222 | 1,013,248 | 293,381 | 126,454 |
| RBP | 17 | 365-Overhead Conductors & Devices | | | | | | | | | |
| RBP | 18 | Primary HT | DDISPHT | 4,643,826 | 1,952,027 | 1,580,817 | 371,210 | 2,113,503 | 551,026 | 18,633 | 8,637 |
| RBP | 19 | Secondary Demand | DDISTSOL | 287,116 | 150,279 | 121,701 | 28,578 | 135,118 | 0 | 1,175 | 545 |
| RBP | 20 | Secondary Customer | CDISTSOLC | 2,159,233 | 1,609,484 | 1,383,712 | 225,773 | 350,423 | 0 | 139,738 | 59,587 |
| RBP | 21 | Total Account 365 | | 7,090,175 | 3,711,790 | 3,086,229 | 625,561 | 2,599,044 | 551,026 | 159,547 | 68,768 |
| RBP | 22 | 366-Underground Conduit | | | | | | | | | |
| RBP | 23 | Primary HT | DDISPHT | 8,146 | 3,424 | 2,773 | 651 | 3,707 | 967 | 33 | 15 |
| RBP | 24 | Secondary Demand | DDISTSUL | 66,433 | 34,771 | 28,159 | 6,612 | 31,263 | 0 | 272 | 126 |
| RBP | 25 | Secondary Customer | CDISTSULC | 225,135 | 167,815 | 144,275 | 23,541 | 36,537 | 0 | 14,570 | 6,213 |
| RBP | 26 | Total Account 366 | | 299,714 | 206,011 | 175,207 | 30,804 | 71,508 | 967 | 14,875 | 6,354 |
| RBP | 27 | 367-Underground Conductors & Devices | | | | | | | | | |
| RBP | 28 | Primary HT | DDISPHT | 17,857 | 7,506 | 6,079 | 1,427 | 8,127 | 2,119 | 72 | 33 |
| RBP | 29 | Secondary Demand | DDISTSUL | 145,625 | 76,221 | 61,726 | 14,495 | 68,532 | 0 | 596 | 276 |
| RBP | 30 | Secondary Customer | CDISTSULC | 493,514 | 367,863 | 316,261 | 51,603 | 80,093 | 0 | 31,939 | 13,619 |
| RBP | 31 | Total Account 367 | | 656,996 | 451,591 | 384,066 | 67,525 | 156,751 | 2,119 | 32,606 | 13,929 |
| RBP | 32 | 368-Line Transformers | | | | | | | | | |
| RBP | 33 | Secondary Demand | DDISTSLT | 1,094,822 | 573,037 | 464,064 | 108,972 | 515,226 | 0 | 4,481 | 2,077 |
| RBP | 34 | Secondary Customer | CDISTSLT | 3,524,430 | 2,627,098 | 2,258,578 | 368,520 | 571,982 | 0 | 228,089 | 97,262 |
| RBP | 35 | Total Account 368 | | 4,619,252 | 3,200,135 | 2,722,642 | 477,492 | 1,087,208 | 0 | 232,570 | 99,339 |
| RBP | 36 | 369-Services | CUSTSERV | 2,444,132 | 1,173,528 | 950,362 | 223,166 | 1,270,604 | 0 | 0 | 0 |
| RBP | 37 | 370-Meters | CUSTMTR | 956,931 | 322,965 | 277,641 | 45,323 | 588,702 | 45,264 | 0 | 0 |
| RBP | 38 | 373-Street Lighting & Signal Systems | CUSTLTG | 735,150 | 0 | 0 | 0 | 0 | 0 | 509,438 | 225,712 |
| RBP | 39 | TOTAL DISTRIBUTION PLANT | | 32,200,747 | 16,883,721 | 14,074,838 | 2,808,883 | 11,627,450 | 1,892,740 | 1,251,889 | 544,946 |
| RBP | 40 | | | | | | | | | | |
| RBP | 41 | | | | | | | | | | |
| RBP | 42 | | | | | | | | | | |
| RBP | 43 | | | | | | | | | | |
| RBP | 44 | | | | | | | | | | |
| RBP | 45 | | | | | | | | | | |
| RBP | 46 | | | | | | | | | | |
| RBP | 47 | | | | | | | | | | |
| RBP | 48 | | | | | | | | | | |
| RBP | 49 | | | | | | | | | | |
| RBP | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| RBP | 1 | **ELECTRIC PLANT IN SERVICE CONTINUED** | | | | | | | | | |
| RBP | 2 | GENERAL PLANT | | | | | | | | | |
| RBP | 3 | 389-Land and Land Rights | LABOR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 4 | 390-Structures and Improvements | LABOR | 2,339,399 | 1,581,780 | 1,344,039 | 237,741 | 617,254 | 85,711 | 26,926 | 27,728 |
| RBP | 5 | 391-Office Furniture & Equipment | LABOR | 339,224 | 229,366 | 194,892 | 34,474 | 89,505 | 12,429 | 3,904 | 4,021 |
| RBP | 6 | 392-Transportation 8 | LABOR | 507,404 | 343,080 | 291,515 | 51,565 | 133,879 | 18,590 | 5,840 | 6,014 |
| RBP | 7 | 393-Store Equipment | LABOR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 8 | 394-Tools, Shop & Garage Equip. | LABOR | 365,052 | 246,829 | 209,731 | 37,098 | 96,320 | 13,375 | 4,202 | 4,327 |
| RBP | 9 | 395-Laboratory Equipment | LABOR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 10 | 397-Communication Equipment | LABOR | 121,856 | 82,393 | 70,009 | 12,384 | 32,152 | 4,465 | 1,403 | 1,444 |
| RBP | 11 | 398-Miscellaneous Equipment | LABOR | 11,455 | 7,745 | 6,581 | 1,164 | 3,022 | 420 | 132 | 136 |
| RBP | 12 | 399-Reserve Excess | LABOR | (168,000) | (113,593) | (96,520) | (17,073) | (44,327) | (6,155) | (1,934) | (1,991) |
| RBP | 13 | TOTAL GENERAL PLANT | | 3,516,390 | 2,377,600 | 2,020,247 | 357,352 | 927,805 | 128,834 | 40,473 | 41,678 |
| RBP | 14 | | | | | | | | | | |
| RBP | 15 | **TOTAL ELECTRIC PLANT IN SERVICE (Includes Common)** | | 35,717,136 | 19,261,321 | 16,095,085 | 3,166,235 | 12,555,255 | 2,021,574 | 1,292,363 | 586,624 |
| RBP | 16 | | | | | | | | | | |
| RBP | 17 | PLUS: Non Interest Bearing CWIP | DGPLT | 2,567,200 | 1,384,424 | 1,156,848 | 227,576 | 902,420 | 145,302 | 92,890 | 42,164 |
| RBP | 18 | | | | | | | | | | |
| RBP | 19 | **TOTAL ELECTRIC UTILITY PLANT IN SERVICE** | | 38,284,336 | 20,645,745 | 17,251,934 | 3,393,811 | 13,457,674 | 2,166,876 | 1,385,252 | 628,788 |
| RBP | 20 | | | | | | | | | | |
| RBP | 21 | **LESS: ACCUMULATED DEPRECIATION** | | | | | | | | | |
| RBP | 22 | | | | | | | | | | |
| RBP | 23 | INTANGIBLE PLANT ACCUMULATED DEPRECIATION | INTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 24 | | | | | | | | | | |
| RBP | 25 | DISTRIBUTION PLANT ACCUMULATED DEPRECIATION | | | | | | | | | |
| RBP | 26 | 360-Land & Land Rights | PLT_360 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RBP | 27 | 361-Structures & Improvements | PLT_361 | 10 | 4 | 4 | 1 | 5 | 1 | 0 | 0 |
| RBP | 28 | 362-Station Equipment | PLT_362 | 246,881 | 103,776 | 84,041 | 19,735 | 112,361 | 29,294 | 991 | 459 |
| RBP | 29 | 364-Poles,Towers & Fixtures | PLT_364 | 1,293,534 | 677,180 | 563,053 | 114,128 | 474,170 | 100,529 | 29,108 | 12,546 |
| RBP | 30 | 365-Overhead Conductors & Devices | PLT_365 | 869,846 | 455,375 | 378,629 | 76,746 | 318,859 | 67,602 | 19,574 | 8,437 |
| RBP | 31 | 366-Underground Conduit | PLT_366 | 17,913 | 12,312 | 10,471 | 1,841 | 4,274 | 58 | 889 | 380 |
| RBP | 32 | 367-Underground Conductors & Devices | PLT_367 | 82,797 | 56,911 | 48,402 | 8,510 | 19,754 | 267 | 4,109 | 1,755 |
| RBP | 33 | 368-Line Transformers | PLT_368 | 499,340 | 345,934 | 294,317 | 51,617 | 117,527 | 0 | 25,141 | 10,738 |
| RBP | 34 | 369-Services | PLT_369 | 295,671 | 141,964 | 114,967 | 26,997 | 153,707 | 0 | 0 | 0 |
| RBP | 35 | 370-Meters | PLT_370 | 261,696 | 88,323 | 75,928 | 12,395 | 160,995 | 12,379 | 0 | 0 |
| RBP | 36 | 373-Street Lighting & Signal Systems | PLT_373 | 57,174 | 0 | 0 | 0 | 0 | 0 | 39,620 | 17,554 |
| RBP | 37 | TOTAL DISTRIBUTION PLANT ACCUM DEPRECIATION | | 3,624,862 | 1,881,779 | 1,569,811 | 311,968 | 1,361,652 | 210,130 | 119,431 | 51,870 |
| RBP | 38 | | | | | | | | | | |
| RBP | 39 | GENERAL PLANT ACCUM DEPRECIATION | GENLPLT | 1,609,678 | 1,088,381 | 924,798 | 163,583 | 424,716 | 58,976 | 18,527 | 19,079 |
| RBP | 40 | | | | | | | | | | |
| RBP | 41 | **TOTAL ELECTRIC ACCUMULATED DEPRECIATION** | | 5,234,540 | 2,970,159 | 2,494,608 | 475,551 | 1,786,369 | 269,105 | 137,959 | 70,948 |
| RBP | 42 | | | | | | | | | | |
| RBP | 43 | Accum Prov Common Plant in Service 85% | TOTPLT | 142,455 | 76,823 | 64,194 | 12,628 | 50,076 | 8,063 | 5,155 | 2,340 |
| RBP | 44 | Accum Prov Retirement Work in Progress | TOTPLT | (63,162) | (34,062) | (28,462) | (5,599) | (22,203) | (3,575) | (2,285) | (1,037) |
| RBP | 45 | | | | | | | | | | |
| RBP | 46 | **TOTAL ELECTRIC UTILITY ACCUMULATED DEPRECIATION** | | 5,313,834 | 3,012,920 | 2,530,340 | 482,580 | 1,814,242 | 273,593 | 140,828 | 72,251 |
| RBP | 47 | | | | | | | | | | |
| RBP | 48 | **NET ELECTRIC PLANT IN SERVICE** | | 32,970,502 | 17,632,825 | 14,721,594 | 2,911,231 | 11,643,433 | 1,893,283 | 1,244,425 | 556,538 |
| RBP | 49 | | | | | | | | | | |
| RBD | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | Distribution | | | | | | | | | |
| RBO | 7 | Cash Working Capital | OMXPP | 1,026,700 | 658,953 | 556,392 | 102,561 | 293,729 | 46,855 | 15,334 | 11,829 |
| RBO | 8 | Materials and Supplies | TOTPLT | 1,535,700 | 828,163 | 692,027 | 136,136 | 539,828 | 86,920 | 55,567 | 25,223 |
| RBO | 9 | Prepayments - Revenue Related | CLAIMREV | 18,974 | 10,794 | 9,057 | 1,737 | 6,279 | 1,120 | 512 | 268 |
| RBO | 10 | Prepayments - Plant Related | TOTPLT | 7,585 | 4,090 | 3,418 | 672 | 2,666 | 429 | 274 | 125 |
| RBO | 11 | Deferred Debits (Net of Tax) | TOTPLT | 334,500 | 180,387 | 150,735 | 29,653 | 117,583 | 18,933 | 12,103 | 5,494 |
| RBO | 12 | Total Distribution Working Capital | | 2,923,459 | 1,682,388 | 1,411,628 | 270,759 | 960,085 | 154,258 | 83,790 | 42,938 |
| RBO | 13 | TOTAL ADDITIONS TO RATE BASE | | 2,923,459 | 1,682,388 | 1,411,628 | 270,759 | 960,085 | 154,258 | 83,790 | 42,938 |
| RBO | 14 | | | | | | | | | | |
| RBO | 15 | **LESS: DEDUCTIONS TO RATE BASE** | | | | | | | | | |
| RBO | 16 | Customer Deposits | CUSTDEP | 332,400 | 145,617 | 128,114 | 17,503 | 171,675 | 15,109 | 0 | 0 |
| RBO | 17 | Deferred Credits (Net of Tax) | TOTPLT | (104,600) | (56,408) | (47,136) | (9,273) | (36,769) | (5,920) | (3,785) | (1,718) |
| RBO | 18 | Deferred Income Taxes and Credits | TOTPLT | 1,638,700 | 883,708 | 738,442 | 145,267 | 576,034 | 92,750 | 59,294 | 26,914 |
| RBO | 19 | TOTAL DEDUCTIONS TO RATE BASE | | 1,866,500 | 972,917 | 819,420 | 153,497 | 710,940 | 101,938 | 55,509 | 25,196 |
| RBO | 20 | | | | | | | | | | |
| RBO | 21 | | | | | | | | | | |
| RBO | 22 | **TOTAL RATE BASE** | | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| RBO | 23 | | | | | | | | | | |
| RBO | 24 | | | | | | | | | | |
| RBO | 25 | | | | | | | | | | |
| RBO | 26 | | | | | | | | | | |
| RBO | 27 | | | | | | | | | | |
| RBO | 28 | | | | | | | | | | |
| RBO | 29 | | | | | | | | | | |
| RBO | 30 | | | | | | | | | | |
| RBO | 31 | | | | | | | | | | |
| RBO | 32 | | | | | | | | | | |
| RBO | 33 | | | | | | | | | | |
| RBO | 34 | | | | | | | | | | |
| RBO | 35 | | | | | | | | | | |
| RBO | 36 | | | | | | | | | | |
| RBO | 37 | | | | | | | | | | |
| RBO | 38 | | | | | | | | | | |
| RBO | 39 | | | | | | | | | | |
| RBO | 40 | | | | | | | | | | |
| RBO | 41 | | | | | | | | | | |
| RBO | 42 | | | | | | | | | | |
| RBO | 43 | | | | | | | | | | |
| RBO | 44 | | | | | | | | | | |
| RBO | 45 | | | | | | | | | | |
| RBO | 46 | | | | | | | | | | |
| RBO | 47 | | | | | | | | | | |
| RBO | 48 | | | | | | | | | | |
| RBO | 49 | | | | | | | | | | |
| RBO | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| REV | 1 | **OPERATING REVENUES** | | | | | | | | | |
| REV | 2 | | | | | | | | | | |
| REV | 3 | **SALES REVENUES** | | | | | | | | | |
| REV | 4 | Sales of Electricity Revenues - Base | | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| REV | 5 | Purchased Electric Revenues | ENERGY1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| REV | 6 | TOTAL SALES OF ELECTRICITY | | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| REV | 7 | | | | | | | | | | |
| REV | 8 | **OTHER OPERATING REVENUES** | | | | | | | | | |
| REV | 9 | 450-Late Payment Charges | EXP_904 | 28,184 | 26,121 | 20,140 | 5,981 | 2,063 | 0 | 0 | 0 |
| REV | 10 | 454-Rent from Electric Property | PLT_364 | (57,902) | (30,313) | (25,204) | (5,109) | (21,225) | (4,500) | (1,303) | (562) |
| REV | 11 | 456-Other Electric Revenues | CLAIMREV | 2,976 | 1,693 | 1,420 | 272 | 985 | 176 | 80 | 42 |
| REV | 12 | TOTAL OTHER OPERATING REV | | (26,742) | (2,499) | (3,643) | 1,145 | (18,177) | (4,324) | (1,223) | (520) |
| REV | 13 | | | | | | | | | | |
| REV | 14 | **TOTAL OPERATING REVENUES** | | 7,334,342 | 3,614,220 | 2,947,972 | 666,249 | 3,022,725 | 536,984 | 111,405 | 49,008 |
| REV | 15 | | | | | | | | | | |
| REV | 16 | | | | | | | | | | |
| REV | 17 | | | | | | | | | | |
| REV | 18 | | | | | | | | | | |
| REV | 19 | | | | | | | | | | |
| REV | 20 | | | | | | | | | | |
| REV | 21 | | | | | | | | | | |
| REV | 22 | | | | | | | | | | |
| REV | 23 | | | | | | | | | | |
| REV | 24 | | | | | | | | | | |
| REV | 25 | | | | | | | | | | |
| REV | 26 | | | | | | | | | | |
| REV | 27 | | | | | | | | | | |
| REV | 28 | | | | | | | | | | |
| REV | 29 | | | | | | | | | | |
| REV | 30 | | | | | | | | | | |
| REV | 31 | | | | | | | | | | |
| REV | 32 | | | | | | | | | | |
| REV | 33 | | | | | | | | | | |
| REV | 34 | | | | | | | | | | |
| REV | 35 | | | | | | | | | | |
| REV | 36 | | | | | | | | | | |
| REV | 37 | | | | | | | | | | |
| REV | 38 | | | | | | | | | | |
| REV | 39 | | | | | | | | | | |
| REV | 40 | | | | | | | | | | |
| REV | 41 | | | | | | | | | | |
| REV | 42 | | | | | | | | | | |
| REV | 43 | | | | | | | | | | |
| REV | 44 | | | | | | | | | | |
| REV | 45 | | | | | | | | | | |
| REV | 46 | | | | | | | | | | |
| REV | 47 | | | | | | | | | | |
| REV | 48 | | | | | | | | | | |
| REV | 49 | | | | | | | | | | |
| REV | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| EOM | 1 | **OPERATION & MAINTENANCE EXPENSE** | | | | | | | | | |
| EOM | 2 | | | | | | | | | | |
| EOM | 3 | PRODUCTION EXPENSE | | | | | | | | | |
| EOM | 4 | Other Power Supply | | | | | | | | | |
| EOM | 5 | 555 - Purchased Power - Energy | ENERGY1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 6 | Other Power Supply Expenses (Base Rate) | ENERGY1 | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| EOM | 7 | Total Other Power Supply | | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| EOM | 8 | TOTAL PRODUCTION EXPENSE | | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| EOM | 9 | | | | | | | | | | |
| EOM | 10 | DISTRIBUTION EXPENSES | | | | | | | | | |
| EOM | 11 | Operation | | | | | | | | | |
| EOM | 12 | 580-Supervision | DISTPLT | 6,725 | 3,526 | 2,939 | 587 | 2,428 | 395 | 261 | 114 |
| EOM | 13 | 581-Load Dispatch | DISTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 14 | 582-Station Equipment | PLT_362 | 10,670 | 4,485 | 3,632 | 853 | 4,856 | 1,266 | 43 | 20 |
| EOM | 15 | 583-Overhead Lines | OHDIST | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 16 | 584-Underground Lines | UGDIST | 5,700 | 3,918 | 3,332 | 586 | 1,360 | 18 | 283 | 121 |
| EOM | 17 | 585-Street Lighting | PLT_373 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 18 | 586-Metering | CUSTMTR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 19 | 587-Customer Installations | CUST | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 20 | 588-Miscellaneous | DISTPLT | 1,962 | 1,029 | 857 | 171 | 708 | 115 | 76 | 33 |
| EOM | 21 | 589-Rents | DISTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 22 | Total Distribution Operation | | 25,056 | 12,958 | 10,761 | 2,196 | 9,353 | 1,795 | 663 | 288 |
| EOM | 23 | | | | | | | | | | |
| EOM | 24 | Maintenance | | | | | | | | | |
| EOM | 25 | 590-Supervision | LABORDM | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 26 | 591-Structures | PLT_361 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 27 | 592-Station Equipment | PLT_362 | 4,953 | 2,082 | 1,686 | 396 | 2,254 | 588 | 20 | 9 |
| EOM | 28 | 593-Overhead Lines | OHDIST | 724,848 | 379,467 | 315,514 | 63,953 | 265,708 | 56,333 | 16,311 | 7,030 |
| EOM | 29 | 594-Underground Lines | UGDIST | 5,059 | 3,478 | 2,958 | 520 | 1,207 | 16 | 251 | 107 |
| EOM | 30 | 595-Transformers | PLT_368 | 11,262 | 7,802 | 6,638 | 1,164 | 2,651 | 0 | 567 | 242 |
| EOM | 31 | 596-Street Lighting | PLT_373 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 32 | 597-Metering | CUSTMTR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 33 | 598-Miscellaneous | DISTPLT | 2,649 | 1,389 | 1,158 | 231 | 957 | 156 | 103 | 45 |
| EOM | 34 | Total Distribution Maintenance | | 748,771 | 394,217 | 327,953 | 66,264 | 272,776 | 57,093 | 17,252 | 7,434 |
| EOM | 35 | | | | | | | | | | |
| EOM | 36 | TOTAL DISTRIBUTION PLANT O&M EXPENSES | | 773,828 | 407,175 | 338,714 | 68,460 | 282,129 | 58,888 | 17,915 | 7,722 |
| EOM | 37 | | | | | | | | | | |
| EOM | 38 | TOTAL OPER & MAINT EXP (PROD & DIST) | | 1,508,696 | 715,910 | 588,739 | 127,172 | 597,210 | 165,759 | 20,772 | 9,045 |
| EOM | 39 | | | | | | | | | | |
| EOM | 40 | | | | | | | | | | |
| EOM | 41 | | | | | | | | | | |
| EOM | 42 | | | | | | | | | | |
| EOM | 43 | | | | | | | | | | |
| EOM | 44 | | | | | | | | | | |
| EOM | 45 | | | | | | | | | | |
| EOM | 46 | | | | | | | | | | |
| EOM | 47 | | | | | | | | | | |
| EOM | 48 | | | | | | | | | | |
| EOM | 49 | | | | | | | | | | |
| EOM | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| EOM | 51 | **OPERATION & MAINTENANCE EXPENSE CONTINUED** | | | | | | | | | |
| EOM | 52 | | | | | | | | | | |
| EOM | 53 | CUSTOMER ACCOUNTS EXPENSES | | | | | | | | | |
| EOM | 54 | 901-Supervision | LABORCA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 55 | 902-Meter Reading | CUSTMTRDG | 6,521 | 5,346 | 4,596 | 750 | 1,164 | 11 | 0 | 0 |
| EOM | 56 | 903-Customer Records and Collection Expense | CUSTREC | 203,994 | 164,279 | 141,239 | 23,040 | 36,044 | 367 | 455 | 2,849 |
| EOM | 57 | 904-Uncollectible Accounts | EXP_904 | 48,341 | 44,802 | 34,544 | 10,258 | 3,539 | 0 | 0 | 0 |
| EOM | 58 | TOTAL CUSTOMER ACCTS EXPENSE | | 258,856 | 214,427 | 180,379 | 34,048 | 40,747 | 378 | 455 | 2,849 |
| EOM | 59 | | | | | | | | | | |
| EOM | 60 | | | | | | | | | | |
| EOM | 61 | CUSTOMER SERVICE EXPENSES | | | | | | | | | |
| EOM | 62 | 907-Supervision | LABORCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 63 | 908-Customer Assistance | CUSTASST | 18,567 | 11,387 | 9,595 | 1,792 | 5,610 | 1,366 | 57 | 147 |
| EOM | 64 | 909-Informational Advertisement | CUSTADVT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 65 | TOTAL CUSTOMER SERVICE EXPENSE | | 18,567 | 11,387 | 9,595 | 1,792 | 5,610 | 1,366 | 57 | 147 |
| EOM | 66 | | | | | | | | | | |
| EOM | 67 | SALES EXPENSES TOTAL (ACCT 917) | CUSTSALES | 30,590 | 18,760 | 15,808 | 2,952 | 9,243 | 2,250 | 94 | 242 |
| EOM | 68 | | | | | | | | | | |
| EOM | 69 | Total Cust Accts, Cust Serv, & Sales | | 308,013 | 244,574 | 205,782 | 38,792 | 55,601 | 3,994 | 606 | 3,238 |
| EOM | 70 | | | | | | | | | | |
| EOM | 71 | TOTAL OPER & MAINT EXCL A&G | | 1,816,708 | 960,484 | 794,520 | 165,964 | 652,811 | 169,752 | 21,378 | 12,284 |
| EOM | 72 | | | | | | | | | | |
| EOM | 73 | | | | | | | | | | |
| EOM | 74 | ADMINISTRATIVE & GENERAL EXPENSE | | | | | | | | | |
| EOM | 75 | 920-Administrative Salaries | LABOR | 832,078 | 562,608 | 478,048 | 84,560 | 219,545 | 30,486 | 9,577 | 9,862 |
| EOM | 76 | 921-Office Supplies & Expense | LABOR | 302,333 | 204,422 | 173,697 | 30,725 | 79,771 | 11,077 | 3,480 | 3,583 |
| EOM | 77 | 922-Admin Exp Transferred Credit | LABOR | (259,863) | (175,706) | (149,298) | (26,409) | (68,565) | (9,521) | (2,991) | (3,080) |
| EOM | 78 | 923-Outside Service Employed | LABOR | 390,477 | 264,021 | 224,338 | 39,682 | 103,028 | 14,306 | 4,494 | 4,628 |
| EOM | 79 | 924-Property Insurance | TOTPLT | 1,904 | 1,027 | 858 | 169 | 669 | 108 | 69 | 31 |
| EOM | 80 | 925-Injuries and Damages | LABOR | 135,677 | 91,738 | 77,950 | 13,788 | 35,799 | 4,971 | 1,562 | 1,608 |
| EOM | 81 | 926-Employee Pensions & Benefits | LABOR | 368,130 | 248,910 | 211,499 | 37,411 | 97,132 | 13,488 | 4,237 | 4,363 |
| EOM | 82 | 928-Regulatory Commission | CLAIMREV | 296,482 | 168,669 | 141,522 | 27,147 | 98,119 | 17,508 | 7,999 | 4,187 |
| EOM | 83 | 929-Duplicate Charges-Credit | LABOR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EOM | 84 | 930.2-Miscellaneous General | LABOR | 48,145 | 32,553 | 27,660 | 4,893 | 12,703 | 1,764 | 554 | 571 |
| EOM | 85 | 932-Maintenance of General Plant | GENLPLT | 33,637 | 22,744 | 19,325 | 3,418 | 8,875 | 1,232 | 387 | 399 |
| EOM | 86 | TOTAL A&G EXPENSE | | 2,148,999 | 1,420,985 | 1,205,600 | 215,384 | 587,075 | 85,418 | 29,368 | 26,153 |
| EOM | 87 | | | | | | | | | | |
| EOM | 88 | **TOTAL OTHER POWER SUPPLY O&M EXPENSES** | | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| EOM | 89 | **TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES** | | 3,230,840 | 2,072,733 | 1,750,096 | 322,637 | 924,804 | 148,300 | 47,890 | 37,112 |
| EOM | 90 | | | | | | | | | | |
| EOM | 91 | **TOTAL OPERATION & MAINTENANCE EXPENSES** | | 3,965,708 | 2,381,469 | 2,000,121 | 381,348 | 1,239,886 | 255,171 | 50,746 | 38,436 |
| EOM | 92 | | | | | | | | | | |
| EOM | 93 | | | | | | | | | | |
| EOM | 94 | | | | | | | | | | |
| EOM | 95 | | | | | | | | | | |
| EOM | 96 | | | | | | | | | | |
| EOM | 97 | | | | | | | | | | |
| EOM | 98 | | | | | | | | | | |
| EOM | 99 | | | | | | | | | | |
| EOM | 100 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | 360-Land & Land Rights | PLT_360 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EDA | 7 | 361-Structures & Improvements | PLT_361 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EDA | 8 | 362-Station Equipment | PLT_362 | 33,470 | 14,069 | 11,393 | 2,675 | 15,233 | 3,971 | 134 | 62 |
| EDA | 9 | 364-Poles,Towers & Fixtures | PLT_364 | 294,582 | 154,217 | 128,226 | 25,991 | 107,985 | 22,894 | 6,629 | 2,857 |
| EDA | 10 | 365-Overhead Conductors & Devices | PLT_365 | 133,474 | 69,875 | 58,099 | 11,776 | 48,927 | 10,373 | 3,003 | 1,295 |
| EDA | 11 | 366-Underground Conduit | PLT_366 | 4,030 | 2,770 | 2,356 | 414 | 961 | 13 | 200 | 85 |
| EDA | 12 | 367-Underground Conductors & Devices | PLT_367 | 13,255 | 9,111 | 7,748 | 1,362 | 3,162 | 43 | 658 | 281 |
| EDA | 13 | 368-Line Transformers | PLT_368 | 114,539 | 79,350 | 67,511 | 11,840 | 26,958 | 0 | 5,767 | 2,463 |
| EDA | 14 | 369-Services | PLT_369 | 83,164 | 39,930 | 32,337 | 7,593 | 43,234 | 0 | 0 | 0 |
| EDA | 15 | 370-Meters | PLT_370 | 69,906 | 23,593 | 20,282 | 3,311 | 43,006 | 3,307 | 0 | 0 |
| EDA | 16 | 373-Street Lighting & Signal Systems | PLT_373 | 22,993 | 0 | 0 | 0 | 0 | 0 | 15,933 | 7,059 |
| EDA | 17 | 374-Asset Retirement Costs for Distribution Plant | DISTPLTXAR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EDA | 18 | TOTAL DISTRIBUTION PLANT EXPENSE | | 769,412 | 392,916 | 327,953 | 64,963 | 289,467 | 40,601 | 32,325 | 14,103 |
| EDA | 19 | | | | | | | | | | |
| EDA | 20 | GENERAL PLANT DEPREC & AMORT EXP | GENLPLT | 57,126 | 38,625 | 32,820 | 5,805 | 15,073 | 2,093 | 658 | 677 |
| EDA | 21 | | | | | | | | | | |
| EDA | 22 | COMMON PLANT DEPREC & AMORT EXP | TOTPLT | 259,833 | 140,121 | 117,088 | 23,034 | 91,336 | 14,706 | 9,402 | 4,268 |
| EDA | 23 | | | | | | | | | | |
| EDA | 24 | Amortization of Unallocated Depreciation Reserve | TOTPLT | 10,579 | 5,705 | 4,767 | 938 | 3,719 | 599 | 383 | 174 |
| EDA | 25 | | | | | | | | | | |
| EDA | 26 | **TOTAL DEPRECIATION / AMORTIZATION EXPENSE** | | 1,096,950 | 577,368 | 482,628 | 94,740 | 399,595 | 57,999 | 42,767 | 19,222 |
| EDA | 27 | | | | | | | | | | |
| EDA | 28 | | | | | | | | | | |
| EDA | 29 | | | | | | | | | | |
| EDA | 30 | | | | | | | | | | |
| EDA | 31 | | | | | | | | | | |
| EDA | 32 | | | | | | | | | | |
| EDA | 33 | | | | | | | | | | |
| EDA | 34 | | | | | | | | | | |
| EDA | 35 | | | | | | | | | | |
| EDA | 36 | | | | | | | | | | |
| EDA | 37 | | | | | | | | | | |
| EDA | 38 | | | | | | | | | | |
| EDA | 39 | | | | | | | | | | |
| EDA | 40 | | | | | | | | | | |
| EDA | 41 | | | | | | | | | | |
| EDA | 42 | | | | | | | | | | |
| EDA | 43 | | | | | | | | | | |
| EDA | 44 | | | | | | | | | | |
| EDA | 45 | | | | | | | | | | |
| EDA | 46 | | | | | | | | | | |
| EDA | 47 | | | | | | | | | | |
| EDA | 48 | | | | | | | | | | |
| EDA | 49 | | | | | | | | | | |
| EDA | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| TXO | 1 | **OTHER OPERATING EXPENSES** | | | | | | | | | |
| TXO | 2 | | | | | | | | | | |
| TXO | 3 | | | | | | | | | | |
| TXO | 4 | **TAXES OTHER THAN INCOME TAXES** | | | | | | | | | |
| TXO | 5 | | | | | | | | | | |
| TXO | 6 | **General Taxes** | | | | | | | | | |
| TXO | 7 | Payroll Related | LABOR | 120,640 | 81,570 | 69,310 | 12,260 | 31,831 | 4,420 | 1,389 | 1,430 |
| TXO | 8 | PA Property Tax | DGPLT | 19,608 | 10,574 | 8,836 | 1,738 | 6,893 | 1,110 | 709 | 322 |
| TXO | 9 | Total General Taxes | | 140,247 | 92,144 | 78,146 | 13,998 | 38,723 | 5,530 | 2,098 | 1,752 |
| TXO | 10 | | | | | | | | | | |
| TXO | 11 | **Gross Receipt Tax** | CLAIMREV | 102,014 | 58,036 | 48,695 | 9,341 | 33,761 | 6,024 | 2,752 | 1,441 |
| TXO | 12 | **Gross Receipt Tax - Purchased Power** | CLAIMREV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXO | 13 | | | 102,014 | 58,036 | 48,695 | 9,341 | 33,761 | 6,024 | 2,752 | 1,441 |
| TXO | 14 | | | | | | | | | | |
| TXO | 15 | **TOTAL TAXES OTHER THAN INCOME** | | 242,261 | 150,180 | 126,841 | 23,339 | 72,484 | 11,554 | 4,850 | 3,193 |
| TXO | 16 | | | | | | | | | | |
| TXO | 17 | | | | | | | | | | |
| TXO | 18 | | | | | | | | | | |
| TXO | 19 | | | | | | | | | | |
| TXO | 20 | | | | | | | | | | |
| TXO | 21 | | | | | | | | | | |
| TXO | 22 | | | | | | | | | | |
| TXO | 23 | | | | | | | | | | |
| TXO | 24 | | | | | | | | | | |
| TXO | 25 | | | | | | | | | | |
| TXO | 26 | | | | | | | | | | |
| TXO | 27 | | | | | | | | | | |
| TXO | 28 | | | | | | | | | | |
| TXO | 29 | | | | | | | | | | |
| TXO | 30 | | | | | | | | | | |
| TXO | 31 | | | | | | | | | | |
| TXO | 32 | | | | | | | | | | |
| TXO | 33 | | | | | | | | | | |
| TXO | 34 | | | | | | | | | | |
| TXO | 35 | | | | | | | | | | |
| TXO | 36 | | | | | | | | | | |
| TXO | 37 | | | | | | | | | | |
| TXO | 38 | | | | | | | | | | |
| TXO | 39 | | | | | | | | | | |
| TXO | 40 | | | | | | | | | | |
| TXO | 41 | | | | | | | | | | |
| TXO | 42 | | | | | | | | | | |
| TXO | 43 | | | | | | | | | | |
| TXO | 44 | | | | | | | | | | |
| TXO | 45 | | | | | | | | | | |
| TXO | 46 | | | | | | | | | | |
| TXO | 47 | | | | | | | | | | |
| TXO | 48 | | | | | | | | | | |
| TXO | 49 | | | | | | | | | | |
| TXO | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| TXI | 1 | **DEVELOPMENT OF DISTRIBUTION INCOME TAXES** | | | | | | | | | |
| TXI | 2 | | | | | | | | | | |
| TXI | 3 | TOTAL DISTRIBUTION OPERATING REVENUES | SCH REV, LN 14 | 7,334,342 | 3,614,220 | 2,947,972 | 666,249 | 3,022,725 | 536,984 | 111,405 | 49,008 |
| TXI | 4 | LESS: | | | | | | | | | |
| TXI | 5 | OPERATION & MAINTAINENCE EXPENSE | SCH EOM, LN 91 | 3,965,708 | 2,381,469 | 2,000,121 | 381,348 | 1,239,886 | 255,171 | 50,746 | 38,436 |
| TXI | 6 | DEPRECIATION & AMORTIZATION EXPENSE | SCH EDA, LN 26 | 1,096,950 | 577,368 | 482,628 | 94,740 | 399,595 | 57,999 | 42,767 | 19,222 |
| TXI | 7 | TAXES OTHER THAN INCOME TAXES | SCH TXO, LN 15 | 242,261 | 150,180 | 126,841 | 23,339 | 72,484 | 11,554 | 4,850 | 3,193 |
| TXI | 8 | **NET OPERATING INCOME BEFORE TAXES** | | 2,029,423 | 505,203 | 338,382 | 166,821 | 1,310,760 | 212,260 | 13,042 | (11,843) |
| TXI | 9 | LESS: | | | | | | | | | |
| TXI | 10 | Interest Expense (incl amort of debt exp) | RATEBASE | 2,453,383 | 1,322,481 | 1,104,126 | 218,355 | 857,456 | 140,278 | 91,762 | 41,406 |
| TXI | 11 | **BASE TAXABLE INCOME** | | (423,960) | (817,278) | (765,744) | (51,533) | 453,304 | 71,982 | (78,720) | (53,248) |
| TXI | 12 | | | | | | | | | | |
| TXI | 13 | **CALCULATION OF PA STATE INCOME TAXES** | | | | | | | | | |
| TXI | 14 | BASE TAXABLE INCOME | SCH TXI, LN 11 | (423,960) | (817,278) | (765,744) | (51,533) | 453,304 | 71,982 | (78,720) | (53,248) |
| TXI | 15 | PLUS: Unallowable Deductions | | | | | | | | | |
| TXI | 16 | Book Depreciation | TOTPLT | 1,096,900 | 591,530 | 494,292 | 97,237 | 385,581 | 62,084 | 39,689 | 18,016 |
| TXI | 17 | Amortization of Storm Costs | TOTPLT | 45,528 | 24,552 | 20,516 | 4,036 | 16,004 | 2,577 | 1,647 | 748 |
| TXI | 18 | Amortization of Rate Case Expenses | CLAIMREV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 19 | Incr in Deferred Purchased Power Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 20 | LESS: Non-Taxable Income & Allowable Deductions | | | | | | | | | |
| TXI | 21 | Tax Depreciation | TOTPLT | 1,560,756 | 841,675 | 703,318 | 138,357 | 548,635 | 88,338 | 56,473 | 25,634 |
| TXI | 22 | Recovery of Prior Deferred Purchased Power Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 23 | PA STATE TAXABLE INCOME | | (842,288) | (1,042,871) | (954,254) | (88,617) | 306,254 | 48,305 | (93,857) | (60,119) |
| TXI | 24 | **PA STATE INCOME TAXES @ Tax Rate 7.99%** | | (67,299) | (83,325) | (76,245) | (7,081) | 24,470 | 3,860 | (7,499) | (4,803) |
| TXI | 25 | Deferred State Income Tax Dr - Acct 410 | | 124,704 | 67,250 | 56,195 | 11,055 | 43,836 | 7,058 | 4,512 | 2,048 |
| TXI | 26 | Deferred State Income Tax Cr - Acct 411 | | (91,280) | (49,225) | (41,133) | (8,092) | (32,087) | (5,166) | (3,303) | (1,499) |
| TXI | 27 | **TOTAL PA INCOME TAX EXPENSE** | | (33,874) | (65,300) | (61,183) | (4,118) | 36,219 | 5,751 | (6,290) | (4,255) |
| TXI | 28 | | | | | | | | | | |
| TXI | 29 | | | | | | | | | | |
| TXI | 30 | **CALCULATION OF FEDERAL INCOME TAXES** | | | | | | | | | |
| TXI | 31 | PA STATE TAXABLE INCOME | SCH TXI, LN 23 | (842,288) | (1,042,871) | (954,254) | (88,617) | 306,254 | 48,305 | (93,857) | (60,119) |
| TXI | 32 | LESS: | | | | | | | | | |
| TXI | 33 | PA State Income Taxes | | (33,874) | (65,300) | (61,183) | (4,118) | 36,219 | 5,751 | (6,290) | (4,255) |
| TXI | 34 | FEDERAL TAXABLE DISTRIBUTION INCOME | | (808,413) | (977,571) | (893,071) | (84,500) | 270,035 | 42,553 | (87,567) | (55,864) |
| TXI | 35 | **FEDERAL INCOME TAXES @ Tax Rate 21.00%** | | (169,767) | (205,290) | (187,545) | (17,745) | 56,707 | 8,936 | (18,389) | (11,731) |
| TXI | 36 | PLUS: | | | | | | | | | |
| TXI | 37 | Book Depreciation | TOTPLT | (230,349) | (124,221) | (103,801) | (20,420) | (80,972) | (13,038) | (8,335) | (3,783) |
| TXI | 38 | Amortization of Storm Costs | TOTPLT | (9,561) | (5,156) | (4,308) | (848) | (3,361) | (541) | (346) | (157) |
| TXI | 40 | Incr in Deferred Purchased Power Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 39 | Tax Depreciation | TOTPLT | 327,759 | 176,752 | 147,697 | 29,055 | 115,213 | 18,551 | 11,859 | 5,383 |
| TXI | 41 | Recovery of Prior Deferred Purchased Power Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 42 | **TOTAL FEDERAL INCOME TAX EXPENSE** | | (81,918) | (157,915) | (147,958) | (9,957) | 87,588 | 13,908 | (15,210) | (10,289) |
| TXI | 43 | | | | | | | | | | |
| TXI | 44 | **TOTAL PA INCOME TAX EXPENSE** | | (33,874) | (65,300) | (61,183) | (4,118) | 36,219 | 5,751 | (6,290) | (4,255) |
| TXI | 45 | **TOTAL FEDERAL INCOME TAX EXPENSE** | | (81,918) | (157,915) | (147,958) | (9,957) | 87,588 | 13,908 | (15,210) | (10,289) |
| TXI | 46 | **TOTAL INCOME TAX EXPENSE** | | (115,792) | (223,216) | (209,141) | (14,075) | 123,807 | 19,660 | (21,500) | (14,543) |
| TXI | 47 | | | | | | | | | | |
| TXI | 48 | | | | | | | | | | |
| TXI | 49 | | | | | | | | | | |
| TXI | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| TXI | 51 | **DEVELOPMENT OF INCOME TAXES** | | | | | | | | | |
| TXI | 52 | | | | | | | | | | |
| TXI | 53 | **TAX RATES & FACTORS** | | | | | | | | | |
| TXI | 54 | GROSS RECEIPTS TAX RATE | 0.05900 | | | | | | | | |
| TXI | 55 | STATE TAX RATE | 0.07990 | | | | | | | | |
| TXI | 56 | EFFECTIVE STATE TAX RATE | 0.09247 | | | | | | | | |
| TXI | 57 | FEDERAL TAX RATE - CURRENT | 0.21000 | | | | | | | | |
| TXI | 58 | 1 - EFFECTIVE TAX RATE | 0.72688 | | | | | | | | |
| TXI | 59 | EFFECTIVE TAX RATE | 0.27312 | | | | | | | | |
| TXI | 60 | EFFECTIVE FEDERAL RATE | 0.17499 | | | | | | | | |
| TXI | 61 | RETENTION FACTOR | 1.46637 | | | | | | | | |
| TXI | 62 | UNCOLLECTIBLES EXPENSE FACTOR | 0.00280 | | | | | | | | |
| TXI | 63 | | | | | | | | | | |
| TXI | 64 | **State Tax Income Adjustment** | | | | | | | | | |
| TXI | 65 | **(For Future Test Year 12 Months Ended September 30 2025)** | | | | | | | | | |
| TXI | 66 | Operating Income Before Income Taxes | | 1,431,530 | 819,243 | 687,208 | 132,035 | 470,987 | 85,930 | 36,183 | 19,188 |
| TXI | 67 | Less Interest Expense (incl amort of debt exp) | RATEBASE | 360,935 | 194,560 | 162,436 | 32,124 | 126,147 | 20,637 | 13,500 | 6,091 |
| TXI | 68 | Pretax Income | | 1,070,594 | 624,683 | 524,772 | 99,911 | 344,840 | 65,292 | 22,683 | 13,096 |
| TXI | 69 | **Add: Additional Taxable Income and Unallowable Deductions** | | | | | | | | | |
| TXI | 70 | Book Depreciation | TOTPLT | 261,300 | 140,912 | 117,749 | 23,164 | 91,852 | 14,789 | 9,455 | 4,292 |
| TXI | 71 | Amortization of Deferred Storm Costs | TOTPLT | 53,100 | 28,635 | 23,928 | 4,707 | 18,666 | 3,005 | 1,921 | 872 |
| TXI | 72 | Amortization of Rate Case Expenditures | CLAIMREV | 29,700 | 16,896 | 14,177 | 2,719 | 9,829 | 1,754 | 801 | 419 |
| TXI | 73 | Increase inDeferred Purchased Gas Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 74 | Total | | 344,100 | 186,444 | 155,854 | 30,590 | 120,347 | 19,549 | 12,177 | 5,583 |
| TXI | 75 | **Deduct: Non-Taxable Income and Allowable Deductions** | | | | | | | | | |
| TXI | 76 | Book Depreciation | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 77 | Rate Case Expenditures | CLAIMREV | 212,500 | 120,892 | 101,434 | 19,457 | 70,325 | 12,548 | 5,733 | 3,001 |
| TXI | 78 | Prior Deferred Purchased Gas Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 79 | Total | | 212,500 | 120,892 | 101,434 | 19,457 | 70,325 | 12,548 | 5,733 | 3,001 |
| TXI | 80 | **State Taxable Income** | | 1,202,194 | 690,235 | 579,191 | 111,044 | 394,862 | 72,293 | 29,127 | 15,678 |
| TXI | 81 | Current Tax Provision - State Taxable Income 7.99% | | 96,055 | 55,150 | 46,277 | 8,872 | 31,549 | 5,776 | 2,327 | 1,253 |
| TXI | 82 | Deferred Income Tax Dr.- Account 410 | | 16,979 | 9,659 | 8,105 | 1,555 | 5,619 | 1,003 | 458 | 240 |
| TXI | 83 | Deferred Income Tax Cr.- Account 411 | | (27,494) | (14,897) | (12,453) | (2,444) | (9,616) | (1,562) | (973) | (446) |
| TXI | 84 | **Total State Income Taxes** | | 85,540 | 49,912 | 41,929 | 7,983 | 27,553 | 5,217 | 1,812 | 1,046 |
| TXI | 85 | | | | | | | | | | |
| TXI | 86 | **Federal Tax Income Adjustment** | | | | | | | | | |
| TXI | 87 | **(For Future Test Year 12 Months Ended September 30 2025)** | | | | | | | | | |
| TXI | 88 | State Taxable Income | | 1,202,194 | 690,235 | 579,191 | 111,044 | 394,862 | 72,293 | 29,127 | 15,678 |
| TXI | 89 | Less State Income Taxes | | 85,540 | 49,912 | 41,929 | 7,983 | 27,553 | 5,217 | 1,812 | 1,046 |
| TXI | 90 | Adjusted Taxable Income | | 1,116,654 | 640,323 | 537,262 | 103,061 | 367,309 | 67,076 | 27,315 | 14,632 |
| TXI | 91 | **Total Federal Income Taxes @ Tax Rate 21.00%** | | 234,497 | 134,468 | 112,825 | 21,643 | 77,135 | 14,086 | 5,736 | 3,073 |
| TXI | 92 | Plus: Deferred Federal Income Tax | | | | | | | | | |
| TXI | 93 | Book/Tax Depreciation | TOTPLT | (54,873) | (29,592) | (24,727) | (4,864) | (19,289) | (3,106) | (1,985) | (901) |
| TXI | 94 | Amortization of Deferred Storm Costs | TOTPLT | (6,237) | (3,363) | (2,811) | (553) | (2,192) | (353) | (226) | (102) |
| TXI | 95 | Amortized/Deferred Rate Case Expenditures | CLAIMREV | 33,474 | 19,043 | 15,978 | 3,065 | 11,078 | 1,977 | 903 | 473 |
| TXI | 96 | Amortized/Deferred Purchased Power Costs | TOTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TXI | 97 | **Total Federal Income Taxes** | | 206,861 | 120,556 | 101,266 | 19,291 | 66,732 | 12,604 | 4,428 | 2,542 |
| TXI | 98 | | | | | | | | | | |
| TXI | 99 | | | | | | | | | | |
| TXI | 100 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| LAB | 1 | **DEVELOPMENT OF LABOR ALLOCATION FACTOR** | | | | | | | | | |
| LAB | 2 | | | | | | | | | | |
| LAB | 3 | **PRODUCTION OTHER LABOR EXPENSE** | | | | | | | | | |
| LAB | 4 | 555-Purchased Power | OX_PROD | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 5 | TOTAL PRODUCTION OTHER LABOR EXP | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 6 | | | | | | | | | | |
| LAB | 7 | **DISTRIBUTION LABOR EXPENSE** | | | | | | | | | |
| LAB | 8 | Operation | | | | | | | | | |
| LAB | 9 | 583-Overhead Lines | OX_583 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 10 | 584-Underground Lines | OX_584 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 11 | 586-Metering | OX_586 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 12 | 587-Customer Installations | OX_587 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 13 | 588-Miscellaneous | OX_588 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 14 | Total Operation | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 15 | Maintenance | | | | | | | | | |
| LAB | 16 | 591-Structures | MX_591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 17 | 592-Station Equipment | MX_592 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 18 | 593-Overhead Lines | MX_593 | 155,866 | 81,598 | 67,846 | 13,752 | 57,136 | 12,113 | 3,507 | 1,512 |
| LAB | 19 | 594-Underground Lines | MX_594 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 20 | 595-Transformers | MX_595 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 21 | 596-Street Lighting | MX_596 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 22 | 598-Miscellaneous | MX_598 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 23 | Total Maintenance | | 155,866 | 81,598 | 67,846 | 13,752 | 57,136 | 12,113 | 3,507 | 1,512 |
| LAB | 24 | TOTAL DISTRIBUTION | | 155,866 | 81,598 | 67,846 | 13,752 | 57,136 | 12,113 | 3,507 | 1,512 |
| LAB | 25 | | | | | | | | | | |
| LAB | 26 | **CUSTOMER ACCOUNTS LABOR EXPENSE** | | | | | | | | | |
| LAB | 27 | 902-Customer Meter Reading | CUSTMTRDG | 3,763 | 3,085 | 2,652 | 433 | 672 | 6 | 0 | 0 |
| LAB | 28 | 903-Customer Records and Collection Expense | CUSTREC | 180,004 | 144,959 | 124,629 | 20,330 | 31,805 | 324 | 402 | 2,514 |
| LAB | 29 | **TOTAL CUSTOMER ACCOUNTS LABOR EXP** | | 183,767 | 148,044 | 127,281 | 20,763 | 32,477 | 330 | 402 | 2,514 |
| LAB | 30 | | | | | | | | | | |
| LAB | 31 | **CUSTOMER SERVICE LABOR EXP** | | | | | | | | | |
| LAB | 32 | 908-Customer Assistance | CUSTASST | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 33 | 909-Advertisement | CUSTADVT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 34 | 910-Miscellaneous CS | CUSTCSM | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 35 | TOTAL CUSTOMER SERVICE LABOR EXP | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 36 | | | | | | | | | | |
| LAB | 37 | **SALES LABOR EXPENSE (ACCT 917)** | OX_CS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 38 | | | | | | | | | | |
| LAB | 39 | ADMINISTRATIVE & GENERAL EXPENSE | | | | | | | | | |
| LAB | 40 | 920-Administrative Salaries | LABORXAG | 57,345 | 38,773 | 32,946 | 5,828 | 15,130 | 2,101 | 660 | 680 |
| LAB | 41 | 921-Office Supplies & Expense | LABORXAG | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LAB | 42 | **ADMIN & GENERAL LABOR EXP** | | 57,345 | 38,773 | 32,946 | 5,828 | 15,130 | 2,101 | 660 | 680 |
| LAB | 43 | **TOT OPER & MAINTENANCE LABOR** | | 396,977 | 268,415 | 228,072 | 40,343 | 104,743 | 14,544 | 4,569 | 4,705 |
| LAB | 44 | | | | | | | | | | |
| LAB | 45 | | | | | | | | | | |
| LAB | 46 | | | | | | | | | | |
| LAB | 47 | | | | | | | | | | |
| LAB | 48 | | | | | | | | | | |
| LAB | 49 | | | | | | | | | | |
| LAB | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AF | 1 | **ALLOCATION FACTOR TABLE** | | | | | | | | | |
| AF | 2 | **EXTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AF | 3 | | | | | | | | | | |
| AF | 4 | **DEMAND** | | | | | | | | | |
| AF | 5 | DEMAND - TRANSMISSION RELATED | | | | | | | | | |
| AF | 6 | | | | | | | | | | |
| AF | 7 | | | | | | | | | | |
| AF | 8 | | | | | | | | | | |
| AF | 9 | | | | | | | | | | |
| AF | 10 | | | | | | | | | | |
| AF | 11 | | | | | | | | | | |
| AF | 12 | | | | | | | | | | |
| AF | 13 | DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand) | | | | | | | | | |
| AF | 14 | Demand Distribution Primary High Tension | DDISPHT | 19,120 | 8,037 | 6,509 | 1,528 | 8,702 | 2,269 | 77 | 36 |
| AF | 15 | Demand Distribution Primary Overhead Lines | DDISTPOL | 19,120 | 8,037 | 6,509 | 1,528 | 8,702 | 2,269 | 77 | 36 |
| AF | 16 | Demand Distribution Primary Underground Lines | DDISTPUL | 19,120 | 8,037 | 6,509 | 1,528 | 8,702 | 2,269 | 77 | 36 |
| AF | 17 | | | | | | | | | | |
| AF | 18 | Demand Distribution Secondary Overhead Lines | DDISTSOL | 18,744 | 9,811 | 7,945 | 1,866 | 8,821 | 0 | 77 | 36 |
| AF | 19 | Demand Distribution Secondary Underground Lines | DDISTSUL | 18,744 | 9,811 | 7,945 | 1,866 | 8,821 | 0 | 77 | 36 |
| AF | 20 | Demand Distribution Line Transformers | DDISTSLT | 18,744 | 9,811 | 7,945 | 1,866 | 8,821 | 0 | 77 | 36 |
| AF | 21 | | | | | | | | | | |
| AF | 22 | | | | | | | | | | |
| AF | 23 | | | | | | | | | | |
| AF | 24 | | | | | | | | | | |
| AF | 25 | **ENERGY** | | | | | | | | | |
| AF | 26 | Energy @ Delivery kWh | ENERGY1 | 81,167,096 | 34,100,228 | 27,615,505 | 6,484,723 | 34,801,134 | 11,804,030 | 315,478 | 146,226 |
| AF | 27 | Energy @ Meter kWh Sales | ENERGY2 | 81,167,096 | 34,100,228 | 27,615,505 | 6,484,723 | 34,801,134 | 11,804,030 | 315,478 | 146,226 |
| AF | 28 | | | | | | | | | | |
| AF | 29 | | | | | | | | | | |
| AF | 30 | | | | | | | | | | |
| AF | 31 | | | | | | | | | | |
| AF | 32 | | | | | | | | | | |
| AF | 33 | | | | | | | | | | |
| AF | 34 | | | | | | | | | | |
| AF | 35 | | | | | | | | | | |
| AF | 36 | | | | | | | | | | |
| AF | 37 | | | | | | | | | | |
| AF | 38 | | | | | | | | | | |
| AF | 39 | | | | | | | | | | |
| AF | 40 | | | | | | | | | | |
| AF | 41 | | | | | | | | | | |
| AF | 42 | | | | | | | | | | |
| AF | 43 | | | | | | | | | | |
| AF | 44 | | | | | | | | | | |
| AF | 45 | | | | | | | | | | |
| AF | 46 | | | | | | | | | | |
| AF | 47 | | | | | | | | | | |
| AF | 48 | | | | | | | | | | |
| AF | 49 | | | | | | | | | | |
| AF | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | | | | | | | | | | |
| AF | 56 | | | | | | | | | | |
| AF | 57 | 364 & 365 - Cust. Dist. Sec Poles, Twrs, Fixt & OH Cond | CDISTSOLC | 69,289 | 51,648 | 44,403 | 7,245 | 11,245 | 0 | 4,484 | 1,912 |
| AF | 58 | 366 & 367 - Cust. Dist. Sec UG Conductors & Devices | CDISTSULC | 69,289 | 51,648 | 44,403 | 7,245 | 11,245 | 0 | 4,484 | 1,912 |
| AF | 59 | 368 - Cust Dist Secondary Line Transformers | CDISTSLT | 69,289 | 51,648 | 44,403 | 7,245 | 11,245 | 0 | 4,484 | 1,912 |
| AF | 60 | | | | | | | | | | |
| AF | 61 | 369-Services | CUSTSERV | 1,280,029 | 614,594 | 497,719 | 116,875 | 665,435 | 0 | 0 | 0 |
| AF | 62 | 370-Meters | CUSTMTR | 956,931 | 322,965 | 277,641 | 45,323 | 588,702 | 45,264 | 0 | 0 |
| AF | 63 | | | | | | | | | | |
| AF | 64 | 373-Street Lighting & Signal Systems | CUSTLTG | 735,150 | 0 | 0 | 0 | 0 | 0 | 509,438 | 225,712 |
| AF | 65 | | | | | | | | | | |
| AF | 66 | Customer Deposits | CUSTDEP | 64,323 | 28,179 | 24,792 | 3,387 | 33,221 | 2,924 | 0 | 0 |
| AF | 67 | | | | | | | | | | |
| AF | 68 | 902-Meter Reading Expense | CUSTMTRDG | 5,250 | 4,304 | 3,700 | 604 | 937 | 9 | 0 | 0 |
| AF | 69 | 903-Customer Records and Collections | CUSTREC | 64,519 | 51,958 | 44,671 | 7,287 | 11,400 | 116 | 144 | 901 |
| AF | 70 | | | | | | | | | | |
| AF | 71 | 908-Customer Assistance | CUSTASST | 1.0000 | 0.6133 | 0.5168 | 0.0965 | 0.3022 | 0.0736 | 0.0031 | 0.0079 |
| AF | 72 | 909-Informational Advertising | CUSTADVT | 1.0000 | 0.6133 | 0.5168 | 0.0965 | 0.3022 | 0.0736 | 0.0031 | 0.0079 |
| AF | 73 | 910-Miscellaneous Customer Service | CUSTCSM | 1.0000 | 0.6133 | 0.5168 | 0.0965 | 0.3022 | 0.0736 | 0.0031 | 0.0079 |
| AF | 74 | 917- Sales Expense | CUSTSALES | 1.0000 | 0.6133 | 0.5168 | 0.0965 | 0.3022 | 0.0736 | 0.0031 | 0.0079 |
| AF | 75 | | | | | | | | | | |
| AF | 76 | Number of Bills | CUSTBILLS | 64,519 | 51,958 | 44,671 | 7,287 | 11,400 | 116 | 144 | 901 |
| AF | 77 | Number of Customers | CUST | 64,044 | 51,648 | 44,403 | 7,245 | 11,245 | 108 | 144 | 899 |
| AF | 78 | Number of Residential Customers | CUSTRES | 51,648 | 51,648 | 44,403 | 7,245 | 0 | 0 | 0 | 0 |
| AF | 79 | Number of Lights (Annual) | CUSTLTGS | 6,396 | 0 | 0 | 0 | 0 | 0 | 4,484 | 1,912 |
| AF | 80 | | | | | | | | | | |
| AF | 81 | | | | | | | | | | |
| AF | 82 | | | | | | | | | | |
| AF | 83 | | | | | | | | | | |
| AF | 84 | | | | | | | | | | |
| AF | 85 | | | | | | | | | | |
| AF | 86 | | | | | | | | | | |
| AF | 87 | | | | | | | | | | |
| AF | 88 | | | | | | | | | | |
| AF | 89 | | | | | | | | | | |
| AF | 90 | | | | | | | | | | |
| AF | 91 | | | | | | | | | | |
| AF | 92 | | | | | | | | | | |
| AF | 93 | | | | | | | | | | |
| AF | 94 | | | | | | | | | | |
| AF | 95 | | | | | | | | | | |
| AF | 96 | | | | | | | | | | |
| AF | 97 | | | | | | | | | | |
| AF | 98 | | | | | | | | | | |
| AF | 99 | | | | | | | | | | |
| AF | 100 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION (a) | ALLOCATION BASIS (b) | TOTAL ELECTRIC COMPANY (c) | Total Residential (d) | Residential SC1 (e) | Residential Space/Water Htg SC1 (f) | Small Commercial & Industrial - Sec SC2-S (g) | Large Commercial & Industrial - Pri SC2-P (h) | Municipal Street Lighting SC3 (i) | Private Lighting SC4 (j) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AF | 101 | **ALLOCATION FACTOR TABLE CONTINUED** | | | | | | | | | |
| AF | 102 | **INTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AF | 103 | | | | | | | | | | |
| AF | 104 | **Plant Related** | | | | | | | | | |
| AF | 105 | Intangible Plant | INTPLT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 106 | Distribution Plant in Service | DISTPLT | 32,200,747 | 16,883,721 | 14,074,838 | 2,808,883 | 11,627,450 | 1,892,740 | 1,251,889 | 544,946 |
| AF | 107 | General Plant in Service | GENLPLT | 3,516,390 | 2,377,600 | 2,020,247 | 357,352 | 927,805 | 128,834 | 40,473 | 41,678 |
| AF | 108 | Total Electric Plant In Service | TOTPLT | 35,717,136 | 19,261,321 | 16,095,085 | 3,166,235 | 12,555,255 | 2,021,574 | 1,292,363 | 586,624 |
| AF | 109 | | | | | | | | | | |
| AF | 110 | Distribution Plant Excl Asset Retirement | DISTPLTXAR | 32,200,747 | 16,883,721 | 14,074,838 | 2,808,883 | 11,627,450 | 1,892,740 | 1,251,889 | 544,946 |
| AF | 111 | Total Distribution and General Plant | DGPLT | 35,717,136 | 19,261,321 | 16,095,085 | 3,166,235 | 12,555,255 | 2,021,574 | 1,292,363 | 586,624 |
| AF | 112 | Rate Base | RATEBASE | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| AF | 113 | | | | | | | | | | |
| AF | 114 | Account 360 | PLT_360 | 1,090,953 | 458,581 | 371,374 | 87,207 | 496,516 | 129,450 | 4,377 | 2,029 |
| AF | 115 | Account 361 | PLT_361 | (2,832) | (1,190) | (964) | (226) | (1,289) | (336) | (11) | (5) |
| AF | 116 | Account 362 | PLT_362 | 1,272,591 | 534,932 | 433,206 | 101,726 | 579,183 | 151,003 | 5,106 | 2,367 |
| AF | 117 | Account 364 | PLT_364 | 13,037,686 | 6,825,381 | 5,675,076 | 1,150,305 | 4,779,222 | 1,013,248 | 293,381 | 126,454 |
| AF | 118 | Account 365 | PLT_365 | 7,090,175 | 3,711,790 | 3,086,229 | 625,561 | 2,599,044 | 551,026 | 159,547 | 68,768 |
| AF | 119 | Account 366 | PLT_366 | 299,714 | 206,011 | 175,207 | 30,804 | 71,508 | 967 | 14,875 | 6,354 |
| AF | 120 | Account 367 | PLT_367 | 656,996 | 451,591 | 384,066 | 67,525 | 156,751 | 2,119 | 32,606 | 13,929 |
| AF | 121 | Account 368 | PLT_368 | 4,619,252 | 3,200,135 | 2,722,642 | 477,492 | 1,087,208 | 0 | 232,570 | 99,339 |
| AF | 122 | Account 369 | PLT_369 | 2,444,132 | 1,173,528 | 950,362 | 223,166 | 1,270,604 | 0 | 0 | 0 |
| AF | 123 | Account 370 | PLT_370 | 956,931 | 322,965 | 277,641 | 45,323 | 588,702 | 45,264 | 0 | 0 |
| AF | 124 | Account 373 | PLT_373 | 735,150 | 0 | 0 | 0 | 0 | 0 | 509,438 | 225,712 |
| AF | 125 | Distribution Overhead Plant in Service | OHDIST | 20,127,861 | 10,537,171 | 8,761,304 | 1,775,866 | 7,378,266 | 1,564,274 | 452,928 | 195,222 |
| AF | 126 | Distribution Underground Plant in Service | UGDIST | 956,710 | 657,601 | 559,273 | 98,329 | 228,260 | 3,085 | 47,481 | 20,283 |
| AF | 127 | Accounts 360 & 361 | PLT_3601 | 1,088,121 | 457,390 | 370,410 | 86,980 | 495,227 | 129,114 | 4,366 | 2,024 |
| AF | 128 | | | | | | | | | | |
| AF | 129 | | | | | | | | | | |
| AF | 130 | | | | | | | | | | |
| AF | 131 | Residential | DPLTRES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 132 | Residential Heating | DPLTRH | 9,320,577 | 9,320,577 | 9,320,577 | 0 | 0 | 0 | 0 | 0 |
| AF | 133 | General Service | DPLTGS | 1,874,195 | 1,874,195 | 0 | 1,874,195 | 0 | 0 | 0 | 0 |
| AF | 134 | Primary Distribution | DPLTPRID | 7,606,526 | 0 | 0 | 0 | 7,606,526 | 0 | 0 | 0 |
| AF | 135 | High Tension | DPLTHT | 1,567,359 | 0 | 0 | 0 | 0 | 1,567,359 | 0 | 0 |
| AF | 136 | Electric Propulsion | DPLTEP | 500,408 | 0 | 0 | 0 | 0 | 0 | 500,408 | 0 |
| AF | 137 | Lighting | DPLTLCUST | 215,505 | 0 | 0 | 0 | 0 | 0 | 0 | 215,505 |
| AF | 138 | | | | | | | | | | |
| AF | 139 | | | | | | | | | | |
| AF | 140 | | | | | | | | | | |
| AF | 141 | | | | | | | | | | |
| AF | 142 | | | | | | | | | | |
| AF | 143 | | | | | | | | | | |
| AF | 144 | | | | | | | | | | |
| AF | 145 | | | | | | | | | | |
| AF | 146 | | | | | | | | | | |
| AF | 147 | | | | | | | | | | |
| AF | 148 | | | | | | | | | | |
| AF | 149 | | | | | | | | | | |
| AF | 150 | | | | | | | | | | |

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

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AF | 151 | **ALLOCATION FACTOR TABLE CONTINUED** | | | | | | | | | |
| AF | 152 | **INTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AF | 153 | | | | | | | | | | |
| AF | 154 | **Production Expense Related** | | | | | | | | | |
| AF | 155 | Account 555 | OX_555 | 734,868 | 308,736 | 250,024 | 58,711 | 315,081 | 106,871 | 2,856 | 1,324 |
| AF | 156 | O&M Expense Production Other | OX_PROD | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 157 | Labor Production Operation | LABORPO | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 158 | | | | | | | | | | |
| AF | 159 | | | | | | | | | | |
| AF | 160 | **Distribution Expense Related** | | | | | | | | | |
| AF | 161 | Account 580 | OX_580 | 6,725 | 3,526 | 2,939 | 587 | 2,428 | 395 | 261 | 114 |
| AF | 162 | Account 581 | OX_581 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 163 | Account 582 | OX_582 | 10,670 | 4,485 | 3,632 | 853 | 4,856 | 1,266 | 43 | 20 |
| AF | 164 | Account 583 | OX_583 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 165 | Account 584 | OX_584 | 5,700 | 3,918 | 3,332 | 586 | 1,360 | 18 | 283 | 121 |
| AF | 166 | Account 585 | OX_585 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 167 | Account 586 | OX_586 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 168 | Account 587 | OX_587 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 169 | Account 588 | OX_588 | 1,962 | 1,029 | 857 | 171 | 708 | 115 | 76 | 33 |
| AF | 170 | Account 589 | OX_589 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 171 | Account 591 | MX_591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 172 | Account 592 | MX_592 | 4,953 | 2,082 | 1,686 | 396 | 2,254 | 588 | 20 | 9 |
| AF | 173 | Account 593 | MX_593 | 724,848 | 379,467 | 315,514 | 63,953 | 265,708 | 56,333 | 16,311 | 7,030 |
| AF | 174 | Account 594 | MX_594 | 5,059 | 3,478 | 2,958 | 520 | 1,207 | 16 | 251 | 107 |
| AF | 175 | Account 595 | MX_595 | 11,262 | 7,802 | 6,638 | 1,164 | 2,651 | 0 | 567 | 242 |
| AF | 176 | Account 596 | MX_596 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 177 | Account 597 | MX_597 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 178 | Account 598 | MX_598 | 2,649 | 1,389 | 1,158 | 231 | 957 | 156 | 103 | 45 |
| AF | 179 | O&M Accounts 581-589 | OX_DIST | 18,332 | 9,432 | 7,822 | 1,610 | 6,925 | 1,400 | 402 | 174 |
| AF | 180 | O&M Accounts 591-598 | MX_DIST | 748,771 | 394,217 | 327,953 | 66,264 | 272,776 | 57,093 | 17,252 | 7,434 |
| AF | 181 | | | | | | | | | | |
| AF | 182 | | | | | | | | | | |
| AF | 183 | | | | | | | | | | |
| AF | 184 | | | | | | | | | | |
| AF | 185 | | | | | | | | | | |
| AF | 186 | | | | | | | | | | |
| AF | 187 | | | | | | | | | | |
| AF | 188 | | | | | | | | | | |
| AF | 189 | | | | | | | | | | |
| 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**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AF | 201 | **ALLOCATION FACTOR TABLE CONTINUED** | | | | | | | | | |
| AF | 202 | **INTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AF | 203 | | | | | | | | | | |
| AF | 204 | **Customer Distribution Expense Related** | | | | | | | | | |
| AF | 205 | Account 902 | OX_902 | 6,521 | 5,346 | 4,596 | 750 | 1,164 | 11 | 0 | 0 |
| AF | 206 | Account 903 | OX_903 | 203,994 | 164,279 | 141,239 | 23,040 | 36,044 | 367 | 455 | 2,849 |
| AF | 207 | Account 904 | OX_904 | 48,341 | 44,802 | 34,544 | 10,258 | 3,539 | 0 | 0 | 0 |
| AF | 208 | O&M Accounts 902-905 | OX_CA | 258,856 | 214,427 | 180,379 | 34,048 | 40,747 | 378 | 455 | 2,849 |
| AF | 209 | | | | | | | | | | |
| AF | 210 | Account908 | OX_908 | 18,567 | 11,387 | 9,595 | 1,792 | 5,610 | 1,366 | 57 | 147 |
| AF | 211 | Account909 | OX_909 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 212 | O&M Accounts 908-910 | OX_CS | 18,567 | 11,387 | 9,595 | 1,792 | 5,610 | 1,366 | 57 | 147 |
| AF | 213 | Accounts 901-910 | X_CACS | 277,423 | 225,814 | 189,974 | 35,840 | 46,357 | 1,744 | 512 | 2,996 |
| AF | 214 | | | | | | | | | | |
| AF | 215 | Total O&M less Purchased Power | OMXPP | 3,200,250 | 2,053,973 | 1,734,288 | 319,685 | 915,561 | 146,050 | 47,796 | 36,870 |
| AF | 216 | Total O&M less PP less Payroll less Pension | OMXPPPP | 2,435,143 | 1,536,648 | 1,294,717 | 241,931 | 713,686 | 118,018 | 38,990 | 27,802 |
| AF | 217 | | | | | | | | | | |
| AF | 218 | **Salaries and Wages Expense Related** | | | | | | | | | |
| AF | 219 | Labor Accounts 581-589 | LABORDO | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 220 | Labor Accounts 591-598 | LABORDM | 155,866 | 81,598 | 67,846 | 13,752 | 57,136 | 12,113 | 3,507 | 1,512 |
| AF | 221 | Labor Accounts 902-905 | LABORCA | 183,767 | 148,044 | 127,281 | 20,763 | 32,477 | 330 | 402 | 2,514 |
| AF | 222 | Labor Accounts 908-910 | LABORCS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AF | 223 | Labor Excluding Admin & Gen | LABORXAG | 339,632 | 229,642 | 195,127 | 34,515 | 89,613 | 12,443 | 3,909 | 4,025 |
| AF | 224 | Total Labor Expense | LABOR | 396,977 | 268,415 | 228,072 | 40,343 | 104,743 | 14,544 | 4,569 | 4,705 |
| AF | 225 | | | | | | | | | | |
| AF | 226 | | | | | | | | | | |
| AF | 227 | | | | | | | | | | |
| AF | 228 | | | | | | | | | | |
| AF | 229 | | | | | | | | | | |
| AF | 230 | | | | | | | | | | |
| AF | 231 | | | | | | | | | | |
| AF | 232 | | | | | | | | | | |
| AF | 233 | | | | | | | | | | |
| AF | 234 | | | | | | | | | | |
| AF | 235 | | | | | | | | | | |
| AF | 236 | | | | | | | | | | |
| AF | 237 | | | | | | | | | | |
| AF | 238 | | | | | | | | | | |
| AF | 239 | | | | | | | | | | |
| AF | 240 | | | | | | | | | | |
| AF | 241 | | | | | | | | | | |
| AF | 242 | | | | | | | | | | |
| AF | 243 | | | | | | | | | | |
| AF | 244 | | | | | | | | | | |
| AF | 245 | | | | | | | | | | |
| AF | 246 | | | | | | | | | | |
| AF | 247 | | | | | | | | | | |
| AF | 248 | | | | | | | | | | |
| AF | 249 | | | | | | | | | | |
| AF | 250 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AF | 251 | **REVENUES AND BILLING DETERMINANTS** | | | | | | | | | |
| AF | 252 | | | | | | | | | | |
| AF | 253 | Base Rate Sales Revenue | SALESREV | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| AF | 254 | | | | | | | | | | |
| AF | 255 | Residential | SREVRES | 2,951,615 | 2,951,615 | 2,951,615 | 0 | 0 | 0 | 0 | 0 |
| AF | 256 | Residential Heating | SREVRH | 665,104 | 665,104 | 0 | 665,104 | 0 | 0 | 0 | 0 |
| AF | 257 | Small Commercial & Industrial | SREVGS | 3,040,902 | 0 | 0 | 0 | 3,040,902 | 0 | 0 | 0 |
| AF | 258 | Large Commercial & Industrial | SREVPRID | 541,308 | 0 | 0 | 0 | 0 | 541,308 | 0 | 0 |
| AF | 259 | Municipal Street Lighting | SREVHT | 112,628 | 0 | 0 | 0 | 0 | 0 | 112,628 | 0 |
| AF | 260 | Lighting | SREVLCUST | 49,527 | 0 | 0 | 0 | 0 | 0 | 0 | 49,527 |
| AF | 261 | | | | | | | | | | |
| AF | 262 | | | | | | | | | | |
| AF | 263 | | | | | | | | | | |
| AF | 264 | | | | | | | | | | |
| AF | 265 | Claimed Rate Sales Revenue | CLAIMREV | 9,504,985 | 5,407,411 | 4,537,090 | 870,321 | 3,145,608 | 561,282 | 256,448 | 134,236 |
| AF | 266 | | | | | | | | | | |
| AF | 267 | | | | | | | | | | |
| AF | 268 | | | | | | | | | | |
| AF | 269 | | | | | | | | | | |
| AF | 270 | | | | | | | | | | |
| AF | 271 | **PRESENT REVENUES/EXPENSES FROM SALES INPUT** | | | | | | | | | |
| AF | 272 | | | | | | | | | | |
| AF | 273 | Total Sales of Electricity Revenues | | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| AF | 274 | Sales of Electricity Revenues - Distribution | | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| AF | 275 | | | | | | | | | | |
| AF | 276 | | | | | | | | | | |
| AF | 277 | | | | | | | | | | |
| AF | 278 | | | | | | | | | | |
| AF | 279 | **12 Months Ended September 30, 2024** | | | | | | | | | |
| AF | 280 | **BILLING DETERMINATE INPUTS** | | | | | | | | | |
| AF | 281 | Annual kWh Sales @ Meter | SCH AF, LN 27 | 81,167,096 | 34,100,228 | 27,615,505 | 6,484,723 | 34,801,134 | 11,804,030 | 315,478 | 146,226 |
| AF | 282 | Annual kW - Billed | | 124,001 | 0 | 0 | 0 | 99,483 | 24,518 | 0 | 0 |
| AF | 283 | Number of Customer Bills | SCH AF, LN 76 | 64,519 | 51,958 | 44,671 | 7,287 | 11,400 | 116 | 144 | 901 |
| AF | 284 | | | | | | | | | | |
| AF | 285 | | | | | | | | | | |
| AF | 286 | **RATE OF RETURN** | | | | | | | | | |
| AF | 287 | Rate of Return (Equalized) | SCH AF, LN 287 | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% |
| AF | 288 | | | | | | | | | | |
| AF | 289 | | | | | | | | | | |
| AF | 290 | | | | | | | | | | |
| AF | 291 | | | | | | | | | | |
| AF | 292 | | | | | | | | | | |
| AF | 293 | **12 Months Ended September 30, 2025** | | | | | | | | | |
| AF | 294 | **BILLING DETERMINATE INPUTS** | | | | | | | | | |
| AF | 295 | Annual kWh Sales @ Meter | | 84,427,347 | 35,464,237 | 28,720,125 | 6,744,112 | 36,193,179 | 12,289,759 | 328,097 | 152,075 |
| AF | 296 | Annual kW - Billed | | 145,539 | 0 | | | 112,368 | 33,172 | | |
| AF | 297 | Number of Customer Bills | | 66,596 | 53,714 | 46,179 | 7,535 | 11,695 | 108 | 144 | 935 |
| AF | 298 | | | | | | | | | | |
| AF | 299 | | | | | | | | | | |
| AF | 300 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AP | 1 | **ALLOCATION PROPORTIONS TABLE** | | | | | | | | | |
| AP | 2 | **EXTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AP | 3 | | | | | | | | | | |
| AP | 4 | | | | | | | | | | |
| AP | 5 | DEMAND - TRANSMISSION RELATED | | | | | | | | | |
| AP | 6 | | | | | | | | | | |
| AP | 7 | | | | | | | | | | |
| AP | 8 | | | | | | | | | | |
| AP | 9 | | | | | | | | | | |
| AP | 10 | | | | | | | | | | |
| AP | 11 | | | | | | | | | | |
| AP | 12 | | | | | | | | | | |
| AP | 13 | DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand) | | | | | | | | | |
| AP | 14 | Demand Distribution Primary High Tension | DDISPHT | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 15 | Demand Distribution Primary Overhead Lines | DDISTPOL | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 16 | Demand Distribution Primary Underground Lines | DDISTPUL | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 17 | | | | | | | | | | |
| AP | 18 | Demand Distribution Secondary Overhead Lines | DDISTSOL | 1.00000 | 0.52341 | 0.42387 | 0.09953 | 0.47060 | 0.00000 | 0.00409 | 0.00190 |
| AP | 19 | Demand Distribution Secondary Underground Lines | DDISTSUL | 1.00000 | 0.52341 | 0.42387 | 0.09953 | 0.47060 | 0.00000 | 0.00409 | 0.00190 |
| AP | 20 | Demand Distribution Line Transformers | DDISTSLT | 1.00000 | 0.52341 | 0.42387 | 0.09953 | 0.47060 | 0.00000 | 0.00409 | 0.00190 |
| AP | 21 | | | | | | | | | | |
| AP | 22 | | | | | | | | | | |
| AP | 23 | | | | | | | | | | |
| AP | 24 | | | | | | | | | | |
| AP | 25 | **ENERGY** | | | | | | | | | |
| AP | 26 | Energy @ Delivery kWh | ENERGY1 | 1.00000 | 0.42012 | 0.34023 | 0.07989 | 0.42876 | 0.14543 | 0.00389 | 0.00180 |
| AP | 27 | Energy @ Meter kWh Sales | ENERGY2 | 1.00000 | 0.42012 | 0.34023 | 0.07989 | 0.42876 | 0.14543 | 0.00389 | 0.00180 |
| AP | 28 | | | | | | | | | | |
| AP | 29 | | | | | | | | | | |
| AP | 30 | | | | | | | | | | |
| AP | 31 | | | | | | | | | | |
| AP | 32 | | | | | | | | | | |
| AP | 33 | | | | | | | | | | |
| AP | 34 | | | | | | | | | | |
| AP | 35 | | | | | | | | | | |
| AP | 36 | | | | | | | | | | |
| AP | 37 | | | | | | | | | | |
| AP | 38 | | | | | | | | | | |
| AP | 39 | | | | | | | | | | |
| AP | 40 | | | | | | | | | | |
| AP | 41 | | | | | | | | | | |
| AP | 42 | | | | | | | | | | |
| AP | 43 | | | | | | | | | | |
| AP | 44 | | | | | | | | | | |
| AP | 45 | | | | | | | | | | |
| AP | 46 | | | | | | | | | | |
| AP | 47 | | | | | | | | | | |
| AP | 48 | | | | | | | | | | |
| AP | 49 | | | | | | | | | | |
| AP | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | | | | | | | | | | |
| AP | 56 | | | | | | | | | | |
| AP | 57 | 364 & 365 - Cust. Dist. Sec Poles, Twrs, Fixt & OH Cond | CDISTSOLC | 1.00000 | 0.74540 | 0.64083 | 0.10456 | 0.16229 | 0.00000 | 0.06472 | 0.02760 |
| AP | 58 | 366 & 367 - Cust. Dist. Sec UG Conductors & Devices | CDISTSULC | 1.00000 | 0.74540 | 0.64083 | 0.10456 | 0.16229 | 0.00000 | 0.06472 | 0.02760 |
| AP | 59 | 368 - Cust Dist Secondary Line Transformers | CDISTSLT | 1.00000 | 0.74540 | 0.64083 | 0.10456 | 0.16229 | 0.00000 | 0.06472 | 0.02760 |
| AP | 60 | | | | | | | | | | |
| AP | 61 | 369-Services | CUSTSERV | 1.00000 | 0.48014 | 0.38883 | 0.09131 | 0.51986 | 0.00000 | 0.00000 | 0.00000 |
| AP | 62 | 370-Meters | CUSTMTR | 1.00000 | 0.33750 | 0.29014 | 0.04736 | 0.61520 | 0.04730 | 0.00000 | 0.00000 |
| AP | 63 | | | | | | | | | | |
| AP | 64 | 373-Street Lighting & Signal Systems | CUSTLTG | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.69297 | 0.30703 |
| AP | 65 | | | | | | | | | | |
| AP | 66 | Customer Deposits | CUSTDEP | 1.00000 | 0.43808 | 0.38542 | 0.05266 | 0.51647 | 0.04545 | 0.00000 | 0.00000 |
| AP | 67 | | | | | | | | | | |
| AP | 68 | 902-Meter Reading Expense | CUSTMTRDG | 1.00000 | 0.81981 | 0.70476 | 0.11505 | 0.17848 | 0.00171 | 0.00000 | 0.00000 |
| AP | 69 | 903-Customer Records and Collections | CUSTREC | 1.00000 | 0.80531 | 0.69237 | 0.11294 | 0.17669 | 0.00180 | 0.00223 | 0.01396 |
| AP | 70 | | | | | | | | | | |
| AP | 71 | 908-Customer Assistance | CUSTASST | 1.00000 | 0.61328 | 0.51678 | 0.09651 | 0.30217 | 0.07356 | 0.00307 | 0.00792 |
| AP | 72 | 909-Informational Advertising | CUSTADVT | 1.00000 | 0.61328 | 0.51678 | 0.09651 | 0.30217 | 0.07356 | 0.00307 | 0.00792 |
| AP | 73 | 910-Miscellaneous Customer Service | CUSTCSM | 1.00000 | 0.61328 | 0.51678 | 0.09651 | 0.30217 | 0.07356 | 0.00307 | 0.00792 |
| AP | 74 | 917- Sales Expense | CUSTSALES | 1.00000 | 0.61328 | 0.51678 | 0.09651 | 0.30217 | 0.07356 | 0.00307 | 0.00792 |
| AP | 75 | | | | | | | | | | |
| AP | 76 | Number of Bills | CUSTBILLS | 1.00000 | 0.80531 | 0.69237 | 0.11294 | 0.17669 | 0.00180 | 0.00223 | 0.01396 |
| AP | 77 | Number of Customers | CUST | 1.00000 | 0.80645 | 0.69332 | 0.11313 | 0.17558 | 0.00169 | 0.00225 | 0.01404 |
| AP | 78 | Number of Residential Customers | CUSTRES | 1.00000 | 1.00000 | 0.85972 | 0.14028 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 79 | Number of Lights (Annual) | CUSTLTGS | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.70106 | 0.29894 |
| AP | 80 | | | | | | | | | | |
| AP | 81 | | | | | | | | | | |
| AP | 82 | | | | | | | | | | |
| AP | 83 | | | | | | | | | | |
| AP | 84 | | | | | | | | | | |
| AP | 85 | | | | | | | | | | |
| AP | 86 | | | | | | | | | | |
| AP | 87 | | | | | | | | | | |
| AP | 88 | | | | | | | | | | |
| AP | 89 | | | | | | | | | | |
| AP | 90 | | | | | | | | | | |
| AP | 91 | | | | | | | | | | |
| AP | 92 | | | | | | | | | | |
| AP | 93 | | | | | | | | | | |
| AP | 94 | | | | | | | | | | |
| AP | 95 | | | | | | | | | | |
| AP | 96 | | | | | | | | | | |
| AP | 97 | | | | | | | | | | |
| AP | 98 | | | | | | | | | | |
| AP | 99 | | | | | | | | | | |
| AP | 100 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AP | 101 | **ALLOCATION PROPORTIONS TABLE CONTINUED** | | | | | | | | | |
| AP | 102 | **INTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AP | 103 | | | | | | | | | | |
| AP | 104 | **Plant Related** | | | | | | | | | |
| AP | 105 | Intangible Plant | INTPLT | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 106 | Distribution Plant in Service | DISTPLT | 1.00000 | 0.52433 | 0.43710 | 0.08723 | 0.36109 | 0.05878 | 0.03888 | 0.01692 |
| AP | 107 | General Plant in Service | GENLPLT | 1.00000 | 0.67615 | 0.57452 | 0.10162 | 0.26385 | 0.03664 | 0.01151 | 0.01185 |
| AP | 108 | Total Electric Plant In Service | TOTPLT | 1.00000 | 0.53927 | 0.45063 | 0.08865 | 0.35152 | 0.05660 | 0.03618 | 0.01642 |
| AP | 109 | | | | | | | | | | |
| AP | 110 | Distribution Plant Excl Asset Retirement | DISTPLTXAR | 1.00000 | 0.52433 | 0.43710 | 0.08723 | 0.36109 | 0.05878 | 0.03888 | 0.01692 |
| AP | 111 | Total Distribution and General Plant | DGPLT | 1.00000 | 0.53927 | 0.45063 | 0.08865 | 0.35152 | 0.05660 | 0.03618 | 0.01642 |
| AP | 112 | Rate Base | RATEBASE | 1.00000 | 0.53904 | 0.45004 | 0.08900 | 0.34950 | 0.05718 | 0.03740 | 0.01688 |
| AP | 113 | | | | | | | | | | |
| AP | 114 | Account 360 | PLT_360 | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 115 | Account 361 | PLT_361 | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 116 | Account 362 | PLT_362 | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 117 | Account 364 | PLT_364 | 1.00000 | 0.52351 | 0.43528 | 0.08823 | 0.36657 | 0.07772 | 0.02250 | 0.00970 |
| AP | 118 | Account 365 | PLT_365 | 1.00000 | 0.52351 | 0.43528 | 0.08823 | 0.36657 | 0.07772 | 0.02250 | 0.00970 |
| AP | 119 | Account 366 | PLT_366 | 1.00000 | 0.68736 | 0.58458 | 0.10278 | 0.23859 | 0.00323 | 0.04963 | 0.02120 |
| AP | 120 | Account 367 | PLT_367 | 1.00000 | 0.68736 | 0.58458 | 0.10278 | 0.23859 | 0.00323 | 0.04963 | 0.02120 |
| AP | 121 | Account 368 | PLT_368 | 1.00000 | 0.69278 | 0.58941 | 0.10337 | 0.23536 | 0.00000 | 0.05035 | 0.02151 |
| AP | 122 | Account 369 | PLT_369 | 1.00000 | 0.48014 | 0.38883 | 0.09131 | 0.51986 | 0.00000 | 0.00000 | 0.00000 |
| AP | 123 | Account 370 | PLT_370 | 1.00000 | 0.33750 | 0.29014 | 0.04736 | 0.61520 | 0.04730 | 0.00000 | 0.00000 |
| AP | 124 | Account 373 | PLT_373 | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.69297 | 0.30703 |
| AP | 125 | Distribution Overhead Plant in Service | OHDIST | 1.00000 | 0.52351 | 0.43528 | 0.08823 | 0.36657 | 0.07772 | 0.02250 | 0.00970 |
| AP | 126 | Distribution Underground Plant in Service | UGDIST | 1.00000 | 0.68736 | 0.58458 | 0.10278 | 0.23859 | 0.00323 | 0.04963 | 0.02120 |
| AP | 127 | Accounts 360 & 361 | PLT_3601 | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 128 | | | | | | | | | | |
| AP | 129 | | | | | | | | | | |
| AP | 130 | | | | | | | | | | |
| AP | 131 | Residential | DPLTRES | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 132 | Residential Heating | DPLTRH | 1.00000 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 133 | General Service | DPLTGS | 1.00000 | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 134 | Primary Distribution | DPLTPRID | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 135 | High Tension | DPLTHT | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 | 0.00000 | 0.00000 |
| AP | 136 | Electric Propulsion | DPLTEP | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 | 0.00000 |
| AP | 137 | Lighting | DPLTLCUST | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 |
| AP | 138 | | | | | | | | | | |
| AP | 139 | | | | | | | | | | |
| AP | 140 | | | | | | | | | | |
| AP | 141 | | | | | | | | | | |
| AP | 142 | | | | | | | | | | |
| AP | 143 | | | | | | | | | | |
| AP | 144 | | | | | | | | | | |
| AP | 145 | | | | | | | | | | |
| AP | 146 | | | | | | | | | | |
| AP | 147 | | | | | | | | | | |
| AP | 148 | | | | | | | | | | |
| AP | 149 | | | | | | | | | | |
| AP | 150 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | Account 555 | OX_555 | 1.00000 | 0.42012 | 0.34023 | 0.07989 | 0.42876 | 0.14543 | 0.00389 | 0.00180 |
| AP | 156 | O&M Expense Production Other | OX_PROD | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 157 | Labor Production Operation | LABORPO | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 158 | | | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 159 | | | | | | | | | | |
| AP | 160 | **Distribution Expense Related** | | | | | | | | | |
| AP | 161 | Account 580 | OX_580 | 1.00000 | 0.52433 | 0.43710 | 0.08723 | 0.36109 | 0.05878 | 0.03888 | 0.01692 |
| AP | 162 | Account 581 | OX_581 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 163 | Account 582 | OX_582 | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 164 | Account 583 | OX_583 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 165 | Account 584 | OX_584 | 1.00000 | 0.68736 | 0.58458 | 0.10278 | 0.23859 | 0.00323 | 0.04963 | 0.02120 |
| AP | 166 | Account 585 | OX_585 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 167 | Account 586 | OX_586 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 168 | Account 587 | OX_587 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 169 | Account 588 | OX_588 | 1.00000 | 0.52433 | 0.43710 | 0.08723 | 0.36109 | 0.05878 | 0.03888 | 0.01692 |
| AP | 170 | Account 589 | OX_589 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 171 | Account 591 | MX_591 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 172 | Account 592 | MX_592 | 1.00000 | 0.42035 | 0.34041 | 0.07994 | 0.45512 | 0.11866 | 0.00401 | 0.00186 |
| AP | 173 | Account 593 | MX_593 | 1.00000 | 0.52351 | 0.43528 | 0.08823 | 0.36657 | 0.07772 | 0.02250 | 0.00970 |
| AP | 174 | Account 594 | MX_594 | 1.00000 | 0.68736 | 0.58458 | 0.10278 | 0.23859 | 0.00323 | 0.04963 | 0.02120 |
| AP | 175 | Account 595 | MX_595 | 1.00000 | 0.69278 | 0.58941 | 0.10337 | 0.23536 | 0.00000 | 0.05035 | 0.02151 |
| AP | 176 | Account 596 | MX_596 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 177 | Account 597 | MX_597 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 178 | Account 598 | MX_598 | 1.00000 | 0.52433 | 0.43710 | 0.08723 | 0.36109 | 0.05878 | 0.03888 | 0.01692 |
| AP | 179 | O&M Accounts 581-589 | OX_DIST | 1.00000 | 0.51450 | 0.42668 | 0.08782 | 0.37773 | 0.07636 | 0.02193 | 0.00949 |
| AP | 180 | O&M Accounts 591-598 | MX_DIST | 1.00000 | 0.52649 | 0.43799 | 0.08850 | 0.36430 | 0.07625 | 0.02304 | 0.00993 |
| AP | 181 | | | | | | | | | | |
| AP | 182 | | | | | | | | | | |
| AP | 183 | | | | | | | | | | |
| AP | 184 | | | | | | | | | | |
| AP | 185 | | | | | | | | | | |
| AP | 186 | | | | | | | | | | |
| AP | 187 | | | | | | | | | | |
| AP | 188 | | | | | | | | | | |
| AP | 189 | | | | | | | | | | |
| AP | 190 | | | | | | | | | | |
| AP | 191 | | | | | | | | | | |
| AP | 192 | | | | | | | | | | |
| AP | 193 | | | | | | | | | | |
| AP | 194 | | | | | | | | | | |
| AP | 195 | | | | | | | | | | |
| AP | 196 | | | | | | | | | | |
| AP | 197 | | | | | | | | | | |
| AP | 198 | | | | | | | | | | |
| AP | 199 | | | | | | | | | | |
| AP | 200 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AP | 201 | **ALLOCATION PROPORTIONS TABLE CONTINUED** | | | | | | | | | |
| AP | 202 | **INTERNALLY DEVELOPED ALLOCATION FACTORS** | | | | | | | | | |
| AP | 203 | | | | | | | | | | |
| AP | 204 | **Customer Distribution Expense Related** | | | | | | | | | |
| AP | 205 | Account 902 | OX_902 | 1.00000 | 0.81981 | 0.70476 | 0.11505 | 0.17848 | 0.00171 | 0.00000 | 0.00000 |
| AP | 206 | Account 903 | OX_903 | 1.00000 | 0.80531 | 0.69237 | 0.11294 | 0.17669 | 0.00180 | 0.00223 | 0.01396 |
| AP | 207 | Account 904 | OX_904 | 1.00000 | 0.92679 | 0.71459 | 0.21221 | 0.07321 | 0.00000 | 0.00000 | 0.00000 |
| AP | 208 | O&M Accounts 902-905 | OX_CA | 1.00000 | 0.82836 | 0.69683 | 0.13153 | 0.15741 | 0.00146 | 0.00176 | 0.01101 |
| AP | 209 | | | | | | | | | | |
| AP | 210 | Account908 | OX_908 | 1.00000 | 0.61328 | 0.51678 | 0.09651 | 0.30217 | 0.07356 | 0.00307 | 0.00792 |
| AP | 211 | Account909 | OX_909 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 212 | O&M Accounts 908-910 | OX_CS | 1.00000 | 0.61328 | 0.51678 | 0.09651 | 0.30217 | 0.07356 | 0.00307 | 0.00792 |
| AP | 213 | Accounts 901-910 | X_CACS | 1.00000 | 0.81397 | 0.68478 | 0.12919 | 0.16710 | 0.00629 | 0.00185 | 0.01080 |
| AP | 214 | | | | | | | | | | |
| AP | 215 | Total O&M less Purchased Power | OMXPP | 1.00000 | 0.64182 | 0.54192 | 0.09989 | 0.28609 | 0.04564 | 0.01494 | 0.01152 |
| AP | 216 | Total O&M less PP less Payroll less Pension | OMXPPPP | 1.00000 | 0.63103 | 0.53168 | 0.09935 | 0.29308 | 0.04846 | 0.01601 | 0.01142 |
| AP | 217 | | | | | | | | | | |
| AP | 218 | **Salaries and Wages Expense Related** | | | | | | | | | |
| AP | 219 | Labor Accounts 581-589 | LABORDO | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 220 | Labor Accounts 591-598 | LABORDM | 1.00000 | 0.52351 | 0.43528 | 0.08823 | 0.36657 | 0.07772 | 0.02250 | 0.00970 |
| AP | 221 | Labor Accounts 902-905 | LABORCA | 1.00000 | 0.80561 | 0.69262 | 0.11299 | 0.17673 | 0.00180 | 0.00219 | 0.01368 |
| AP | 222 | Labor Accounts 908-910 | LABORCS | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 223 | Labor Excluding Admin & Gen | LABORXAG | 1.00000 | 0.67615 | 0.57452 | 0.10162 | 0.26385 | 0.03664 | 0.01151 | 0.01185 |
| AP | 224 | Total Labor Expense | LABOR | 1.00000 | 0.67615 | 0.57452 | 0.10162 | 0.26385 | 0.03664 | 0.01151 | 0.01185 |
| AP | 225 | | | | | | | | | | |
| AP | 226 | | | | | | | | | | |
| AP | 227 | | | | | | | | | | |
| AP | 228 | | | | | | | | | | |
| AP | 229 | | | | | | | | | | |
| AP | 230 | | | | | | | | | | |
| AP | 231 | | | | | | | | | | |
| AP | 232 | | | | | | | | | | |
| AP | 233 | | | | | | | | | | |
| AP | 234 | | | | | | | | | | |
| AP | 235 | | | | | | | | | | |
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| AP | 237 | | | | | | | | | | |
| AP | 238 | | | | | | | | | | |
| AP | 239 | | | | | | | | | | |
| AP | 240 | | | | | | | | | | |
| AP | 241 | | | | | | | | | | |
| AP | 242 | | | | | | | | | | |
| AP | 243 | | | | | | | | | | |
| AP | 244 | | | | | | | | | | |
| AP | 245 | | | | | | | | | | |
| AP | 246 | | | | | | | | | | |
| AP | 247 | | | | | | | | | | |
| AP | 248 | | | | | | | | | | |
| AP | 249 | | | | | | | | | | |
| AP | 250 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| AP | 251 | **REVENUES AND BILLING DETERMINANTS** | | | | | | | | | |
| AP | 252 | | | | | | | | | | |
| AP | 253 | Base Rate Sales Revenue | SALESREV | 1.00000 | 0.49133 | 0.40098 | 0.09035 | 0.41311 | 0.07354 | 0.01530 | 0.00673 |
| AP | 254 | | | | | | | | | | |
| AP | 255 | Residential | SREVRES | 1.00000 | 1.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 256 | Residential Heating | SREVRH | 1.00000 | 1.00000 | 0.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 257 | Small Commercial & Industrial | SREVGS | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 | 0.00000 | 0.00000 | 0.00000 |
| AP | 258 | Large Commercial & Industrial | SREVPRID | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 | 0.00000 | 0.00000 |
| AP | 259 | Municipal Street Lighting | SREVHT | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 | 0.00000 |
| AP | 260 | Lighting | SREVLCUST | 1.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | 1.00000 |
| AP | 261 | | | | | | | | | | |
| AP | 262 | | | | | | | | | | |
| AP | 263 | | | | | | | | | | |
| AP | 264 | | | | | | | | | | |
| AP | 265 | Claimed Rate Sales Revenue | CLAIMREV | 1.00000 | 0.56890 | 0.47734 | 0.09156 | 0.33094 | 0.05905 | 0.02698 | 0.01412 |
| AP | 266 | | | | | | | | | | |
| AP | 267 | | | | | | | | | | |
| AP | 268 | | | | | | | | | | |
| AP | 269 | | | | | | | | | | |
| AP | 270 | | | | | | | | | | |
| AP | 271 | **PRESENT REVENUES/EXPENSES FROM SALES INPUT** | | | | | | | | | |
| AP | 272 | | | | | | | | | | |
| AP | 273 | Total Sales of Electricity Revenues | | 1.00000 | 0.49133 | 0.40098 | 0.09035 | 0.41311 | 0.07354 | 0.01530 | 0.00673 |
| AP | 274 | Sales of Electricity Revenues - Distribution | | 1.00000 | 0.49133 | 0.40098 | 0.09035 | 0.41311 | 0.07354 | 0.01530 | 0.00673 |
| AP | 275 | | | | | | | | | | |
| AP | 276 | | | | | | | | | | |
| AP | 277 | | | | | | | | | | |
| AP | 278 | | | | | | | | | | |
| AP | 279 | | | | | | | | | | |
| AP | 280 | | | | | | | | | | |
| AP | 281 | | | | | | | | | | |
| AP | 282 | | | | | | | | | | |
| AP | 283 | | | | | | | | | | |
| AP | 284 | | | | | | | | | | |
| AP | 285 | | | | | | | | | | |
| AP | 286 | | | | | | | | | | |
| AP | 287 | | | | | | | | | | |
| AP | 288 | | | | | | | | | | |
| AP | 289 | | | | | | | | | | |
| AP | 290 | | | | | | | | | | |
| AP | 291 | | | | | | | | | | |
| AP | 292 | | | | | | | | | | |
| AP | 293 | | | | | | | | | | |
| AP | 294 | | | | | | | | | | |
| AP | 295 | | | | | | | | | | |
| AP | 296 | | | | | | | | | | |
| AP | 297 | | | | | | | | | | |
| AP | 298 | | | | | | | | | | |
| AP | 299 | | | | | | | | | | |
| AP | 300 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | **904-Uncollectible Accounts Expense** | | | | | | | | | |
| ADA | 5 | Residential | SREVRES | 18,161 | 18,161 | 18,161 | 0 | 0 | 0 | 0 | 0 |
| ADA | 6 | Residential Heating | SREVRH | 5,393 | 5,393 | 0 | 5,393 | 0 | 0 | 0 | 0 |
| ADA | 7 | Small Commercial & Industrial | SREVGS | 1,860 | 0 | 0 | 0 | 1,860 | 0 | 0 | 0 |
| ADA | 8 | Large Commercial & Industrial | SREVPRID | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADA | 9 | Municipal Street Lighting | SREVHT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADA | 10 | Lighting | SREVLCUST | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADA | 11 | | | | | | | | | | |
| ADA | 12 | | | | | | | | | | |
| ADA | 13 | Total Uncollectible Accounts Expense | EXP_904 | 25,415 | 23,554 | 18,161 | 5,393 | 1,860 | 0 | 0 | 0 |
| ADA | 14 | | | | | | | | | | |
| ADA | 15 | Total Uncollectible Accounts Expense | EXP_904 | 1.00000 | 0.92679 | 0.71459 | 0.21221 | 0.07321 | 0.00000 | 0.00000 | 0.00000 |
| ADA | 16 | | | | | | | | | | |
| ADA | 17 | | | | | | | | | | |
| ADA | 18 | | | | | | | | | | |
| ADA | 19 | | | | | | | | | | |
| ADA | 20 | | | | | | | | | | |
| ADA | 21 | **450-Late Payment Charges** | | | | | | | | | |
| ADA | 22 | Residential | SREVRES | 18,069 | 18,069 | 18,069 | 0 | 0 | 0 | 0 | 0 |
| ADA | 23 | Residential Heating | SREVRH | 4,539 | 4,539 | 0 | 4,539 | 0 | 0 | 0 | 0 |
| ADA | 24 | Small Commercial & Industrial | SREVGS | 9,005 | 0 | 0 | 0 | 9,005 | 0 | 0 | 0 |
| ADA | 25 | Large Commercial & Industrial | SREVPRID | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADA | 26 | Municipal Street Lighting | SREVHT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADA | 27 | Lighting | SREVLCUST | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADA | 28 | | | | | | | | | | |
| ADA | 29 | | | | | | | | | | |
| ADA | 30 | Late Payment Charges | REV_450 | 31,613 | 22,608 | 18,069 | 4,539 | 9,005 | 0 | 0 | 0 |
| ADA | 31 | | | | | | | | | | |
| ADA | 32 | Late Payment Charges | REV_450 | 1.00000 | 0.71516 | 0.57158 | 0.14358 | 0.28484 | 0.00000 | 0.00000 | 0.00000 |
| ADA | 33 | | | | | | | | | | |
| ADA | 34 | | | | | | | | | | |
| ADA | 35 | | | | | | | | | | |
| ADA | 36 | | | | | | | | | | |
| ADA | 37 | | | | | | | | | | |
| ADA | 38 | | | | | | | | | | |
| ADA | 39 | | | | | | | | | | |
| ADA | 40 | | | | | | | | | | |
| ADA | 41 | | | | | | | | | | |
| ADA | 42 | | | | | | | | | | |
| ADA | 43 | | | | | | | | | | |
| ADA | 44 | | | | | | | | | | |
| ADA | 45 | | | | | | | | | | |
| ADA | 46 | | | | | | | | | | |
| ADA | 47 | | | | | | | | | | |
| ADA | 48 | | | | | | | | | | |
| ADA | 49 | | | | | | | | | | |
| ADA | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| RRW | 6 | Net Operating Income (Present Rates) | | 2,145,215 | 728,419 | 547,523 | 180,896 | 1,186,953 | 192,600 | 34,542 | 2,701 |
| RRW | 7 | Rate of Return @ Present Rates | | 6.30% | 3.97% | 3.58% | 5.97% | 9.98% | 9.90% | 2.71% | 0.47% |
| RRW | 8 | Relative Rate of Return | | 1.00 | 0.63 | 0.57 | 0.95 | 1.58 | 1.57 | 0.43 | 0.07 |
| RRW | 9 | Sales Revenue at Present Rates | | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| RRW | 10 | Revenue Present Rates $/kWh | | $0.0872 | $0.1020 | $0.1028 | $0.0986 | $0.0840 | $0.0440 | $0.3433 | $0.3257 |
| RRW | 11 | Revenue Required - $/Month/Customer | | $114.09 | $69.61 | $66.07 | $91.27 | $266.75 | $4,666.45 | $782.14 | $54.97 |
| RRW | 12 | Revenue Present Rates $/kW | | $59.36 | $0.00 | $0.00 | $0.00 | $30.57 | $22.08 | $0.00 | $0.00 |
| RRW | 13 | | | | | | | | | | |
| RRW | 14 | CLAIMED RATE OF RETURN | | | | | | | | | |
| RRW | 15 | ------------------------------------------------------------ | | | | | | | | | |
| RRW | 16 | Claimed Rate of Return | | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% |
| RRW | 17 | Return Required for Claimed Rate of Return | | 3,267,197 | 1,756,851 | 1,466,687 | 290,165 | 1,145,532 | 186,982 | 122,654 | 55,177 |
| RRW | 18 | Sales Revenue Required @ Claimed ROR | | 9,504,985 | 5,407,411 | 4,537,090 | 870,321 | 3,145,608 | 561,282 | 256,448 | 134,236 |
| RRW | 19 | Sales Revenue Deficiency | | 2,143,900 | 1,790,692 | 1,585,475 | 205,217 | 104,706 | 19,974 | 143,820 | 84,708 |
| RRW | 20 | Percent Increase Required | | 29.12% | 49.51% | 53.72% | 30.85% | 3.44% | 3.69% | 127.70% | 171.03% |
| RRW | 21 | Annual Booked kWh Sales | | 84,427,347 | 35,464,237 | 28,720,125 | 6,744,112 | 36,193,179 | 12,289,759 | 328,097 | 152,075 |
| RRW | 22 | Sales Revenue Required $/kWh | | $0.1126 | $0.1525 | $0.1580 | $0.1290 | $0.0869 | $0.0457 | $0.7816 | $0.8827 |
| RRW | 23 | Revenue Deficiency $/kWh | | $0.0254 | $0.0505 | $0.0552 | $0.0304 | $0.0029 | $0.0016 | $0.4383 | $0.5570 |
| RRW | 24 | | | | | | | | | | |
| RRW | 25 | | | | | | | | | | |
| RRW | 26 | PROPOSED RATE OF RETURN | | | | | | | | | |
| RRW | 27 | ------------------------------------------------------------ | | | | | | | | | |
| RRW | 28 | Rate Base at Future Test Year 09/30/2025 | | 39,033,500 | 20,989,261 | 17,522,639 | 3,466,622 | 13,685,770 | 2,233,894 | 1,465,364 | 659,210 |
| RRW | 29 | Proposed Base Electric Sales Revenues | | 9,504,979 | 4,775,423 | 3,896,239 | 879,184 | 3,833,137 | 682,313 | 148,711 | 65,395 |
| RRW | 30 | Base Sales Revenue Deficiency | | 2,143,894 | 1,158,704 | 944,624 | 214,080 | 792,235 | 141,005 | 36,083 | 15,867 |
| RRW | 31 | Return Required for Proposed Revenue | | 3,267,191 | 1,124,864 | 825,836 | 299,028 | 1,833,060 | 308,013 | 14,917 | (13,664) |
| RRW | 32 | Percent Increase Required at Proposed Rates | | 29.12% | 32.04% | 32.00% | 32.19% | 26.05% | 26.05% | 32.04% | 32.04% |
| RRW | 33 | Proposed Rate of Return | | 8.37% | 5.36% | 4.71% | 8.63% | 13.39% | 13.79% | 1.02% | -2.07% |
| RRW | 34 | Relative Rate of Return | | 1.00 | 0.64 | 0.56 | 1.03 | 1.60 | 1.65 | 0.12 | -0.25 |
| RRW | 35 | | | | | | | | | | |
| RRW | 36 | | | | | | | | | | |
| RRW | 37 | | | | | | | | | | |
| RRW | 38 | | | | | | | | | | |
| RRW | 39 | | | | | | | | | | |
| RRW | 40 | | | | | | | | | | |
| RRW | 41 | | | | | | | | | | |
| RRW | 42 | | | | | | | | | | |
| RRW | 43 | | | | | | | | | | |
| RRW | 44 | | | | | | | | | | |
| RRW | 45 | | | | | | | | | | |
| RRW | 46 | | | | | | | | | | |
| RRW | 47 | | | | | | | | | | |
| RRW | 48 | | | | | | | | | | |
| RRW | 49 | | | | | | | | | | |
| RRW | 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| LINE NO. | DESCRIPTION | | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1 | **PRESENT RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS** | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | **RATE OF RETURN** | | 6.30% | 3.97% | 3.58% | 5.97% | 9.98% | 9.90% | 2.71% | 0.47% |
| 4 | | | | | | | | | | |
| 5 | **REVENUES REQUIRED** | | | | | | | | | |
| 6 | **DEMAND COMPONENTS** | 3,265,568 | 3,265,568 | 1,047,665 | 807,791 | 239,874 | 1,790,449 | 416,186 | 8,417 | 2,851 |
| 7 | AVAILABLE COMPONENT | | 0 | 0 | (0) | (0) | 0 | 0 | 0 | 0 |
| 8 | AVAILABLE COMPONENT | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | DEMAND DISTRIBUTION COMPONENT | 3,265,568 | 3,265,568 | 1,047,665 | 807,791 | 239,874 | 1,790,449 | 416,186 | 8,417 | 2,851 |
| 10 | DEMAND DISTRIBUTION HT | | 2,964,186 | 932,287 | 720,070 | 212,218 | 1,605,403 | 416,186 | 7,677 | 2,632 |
| 11 | DEMAND DISTRIBUTION PRIMARY | | 0 | 0 | (0) | (0) | 0 | 0 | 0 | 0 |
| 12 | DEMAND DISTRIBUTION SECONDARY | | 183,481 | 74,922 | 57,815 | 17,106 | 107,884 | 0 | 504 | 172 |
| 13 | DEMAND DISTRIBUTION TRANSFORMERS | | 117,901 | 40,456 | 29,906 | 10,550 | 77,162 | 0 | 236 | 47 |
| 14 | **ENERGY COMPONENTS** | 772,697 | 772,697 | 325,389 | 263,399 | 61,991 | 330,791 | 112,137 | 2,993 | 1,387 |
| 15 | ENERGY OTHER & PUR PWR | | 772,697 | 325,389 | 263,399 | 61,991 | 330,791 | 112,137 | 2,993 | 1,387 |
| 16 | **CUSTOMER COMPONENTS** | 3,322,819 | 3,322,819 | 2,243,664 | 1,880,426 | 363,239 | 919,662 | 12,985 | 101,218 | 45,290 |
| 17 | AVAILABLE COMPONENT | | 0 | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 18 | CUSTOMER DISTR SECONDARY COMPONENT | | 1,360,079 | 927,136 | 765,412 | 161,724 | 343,761 | (0) | 68,817 | 20,365 |
| 19 | AVAILABLE COMPONENT | | 0 | 0 | (0) | (0) | 0 | 0 | 0 | 0 |
| 20 | CUSTOMER SERVICES INVESTMENT | | 288,063 | 90,712 | 67,690 | 23,022 | 197,351 | 0 | (0) | 0 |
| 21 | CUSTOMER METER INVESTMENT | | 149,481 | 36,180 | 30,052 | 6,128 | 105,254 | 8,047 | 0 | 0 |
| 22 | CUSTOMER ACCOUNT EXPENSE | | 1,463,844 | 1,162,247 | 993,871 | 168,376 | 277,142 | 2,812 | 3,075 | 18,568 |
| 23 | CUSTOMER SERVICE EXPENSES | | 51,958 | 31,803 | 26,773 | 5,030 | 15,758 | 3,833 | 158 | 406 |
| 24 | CUSTOMER OTHER | | 9,394 | (4,413) | (3,371) | (1,042) | (19,604) | (1,708) | 29,168 | 5,951 |
| 25 | **TOTAL COMPANY** | 7,361,084 | 7,361,084 | 3,616,719 | 2,951,615 | 665,104 | 3,040,902 | 541,308 | 112,628 | 49,527 |
| 26 | | | | | | | | | | |
| 27 | | | | | | | | | | |
| 28 | | | | | | | | | | |
| 29 | | | | | | | | | | |
| 30 | Annual kWh Sales @ Meter | | 81,167,096 | 34,100,228 | 27,615,505 | 6,484,723 | 34,801,134 | 11,804,030 | 315,478 | 146,226 |
| 31 | Annual kW - Billed | | 124,001 | 0 | 0 | 0 | 99,483 | 24,518 | 0 | 0 |
| 32 | Number of Customer Bills | | 64,519 | 51,958 | 44,671 | 7,287 | 11,400 | 116 | 144 | 901 |
| 33 | | | | | | | | | | |
| 34 | kWh Use per Month per Customer | | 1,258.03 | 656.30 | 618.20 | 889.90 | 3,052.73 | 101,758.88 | 2,190.82 | 162.29 |
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**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| LINE NO. | DESCRIPTION | | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1 | **PRESENT RATE OF RETURN SUMMARY SCHEDULE - UNIT COST** | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | **RATE OF RETURN** | | 6.30% | 3.97% | 3.58% | 5.97% | 9.98% | 9.90% | 2.71% | 0.47% |
| 4 | | | | | | | | | | |
| 5 | **$/KWH** | | | | | | | | | |
| 6 | **DEMAND COMPONENTS** | $0.0387 | $0.0387 | $0.0295 | $0.0281 | $0.0356 | $0.0495 | $0.0339 | $0.0257 | $0.0187 |
| 7 | AVAILABLE COMPONENT | | $0.0000 | $0.0000 | ($0.0000) | ($0.0000) | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| 8 | AVAILABLE COMPONENT | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| 9 | DEMAND DISTRIBUTION COMPONENT | | $0.0387 | $0.0295 | $0.0281 | $0.0356 | $0.0495 | $0.0339 | $0.0257 | $0.0187 |
| 10 | DEMAND DISTRIBUTION HT | | $0.0351 | $0.0263 | $0.0251 | $0.0315 | $0.0444 | $0.0339 | $0.0234 | $0.0173 |
| 11 | DEMAND DISTRIBUTION PRIMARY | | $0.0000 | $0.0000 | ($0.0000) | ($0.0000) | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| 12 | DEMAND DISTRIBUTION SECONDARY | | $0.0022 | $0.0021 | $0.0020 | $0.0025 | $0.0030 | $0.0000 | $0.0015 | $0.0011 |
| 14 | DEMAND DISTRIBUTION TRANSFORMERS | | $0.0014 | $0.0011 | $0.0010 | $0.0016 | $0.0021 | $0.0000 | $0.0007 | $0.0003 |
| 13 | **ENERGY COMPONENTS** | $0.0092 | $0.0092 | $0.0092 | $0.0092 | $0.0092 | $0.0091 | $0.0091 | $0.0091 | $0.0091 |
| 15 | ENERGY OTHER & PUR PWR | | $0.0092 | $0.0092 | $0.0092 | $0.0092 | $0.0091 | $0.0091 | $0.0091 | $0.0091 |
| 16 | **CUSTOMER COMPONENTS** | $0.0394 | $0.0394 | $0.0633 | $0.0655 | $0.0539 | $0.0254 | $0.0011 | $0.3085 | $0.2978 |
| 17 | AVAILABLE COMPONENT | | $0.0000 | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) |
| 18 | CUSTOMER DISTR SECONDARY COMPONENT | | $0.0161 | $0.0261 | $0.0267 | $0.0240 | $0.0095 | $0.0000 | $0.2097 | $0.1339 |
| 19 | AVAILABLE COMPONENT | | $0.0000 | $0.0000 | ($0.0000) | ($0.0000) | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| 20 | CUSTOMER SERVICES INVESTMENT | | $0.0034 | $0.0026 | $0.0024 | $0.0034 | $0.0055 | $0.0000 | $0.0000 | $0.0000 |
| 21 | CUSTOMER METER INVESTMENT | | $0.0018 | $0.0010 | $0.0010 | $0.0009 | $0.0029 | $0.0007 | $0.0000 | $0.0000 |
| 22 | CUSTOMER ACCOUNT EXPENSE | | $0.0173 | $0.0328 | $0.0346 | $0.0250 | $0.0077 | $0.0002 | $0.0094 | $0.1221 |
| 23 | CUSTOMER SERVICE EXPENSES | | $0.0006 | $0.0009 | $0.0009 | $0.0007 | $0.0004 | $0.0003 | $0.0005 | $0.0027 |
| 24 | CUSTOMER OTHER | | $0.0001 | ($0.0001) | ($0.0001) | ($0.0002) | ($0.0005) | ($0.0001) | $0.0889 | $0.0391 |
| 25 | **TOTAL COMPANY** | $0.0872 | $0.0872 | $0.1020 | $0.1028 | $0.0986 | $0.0840 | $0.0440 | $0.3433 | $0.3257 |
| 26 | | | | | | | | | | |
| 27 | **$/KW** | | | | | | | | | |
| 28 | **DEMAND COMPONENTS** | $26.33 | $26.33 | $0.00 | $0.00 | $0.00 | $18.00 | $16.97 | $0.00 | $0.00 |
| 29 | AVAILABLE COMPONENT | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 30 | AVAILABLE COMPONENT | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 31 | DEMAND DISTRIBUTION COMPONENT | | $26.33 | $0.00 | $0.00 | $0.00 | $18.00 | $16.97 | $0.00 | $0.00 |
| 32 | DEMAND DISTRIBUTION HT | | $23.90 | $0.00 | $0.00 | $0.00 | $16.14 | $16.97 | $0.00 | $0.00 |
| 33 | DEMAND DISTRIBUTION PRIMARY | | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 34 | DEMAND DISTRIBUTION SECONDARY | | $1.48 | $0.00 | $0.00 | $0.00 | $1.08 | $0.00 | $0.00 | $0.00 |
| 35 | | | | | | | | | | |
| 36 | **$/MONTH/CUSTOMER** | | | | | | | | | |
| 37 | **CUSTOMER COMPONENTS** | $51.50 | $51.50 | $43.18 | $42.09 | $49.85 | $80.67 | $111.94 | $702.90 | $50.27 |
| 38 | AVAILABLE COMPONENT | | $0.00 | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) |
| 39 | CUSTOMER DISTR SECONDARY COMPONENT | | $21.08 | $17.84 | $17.13 | $22.19 | $30.15 | ($0.00) | $477.90 | $22.60 |
| 40 | AVAILABLE COMPONENT | | $0.00 | $0.00 | ($0.00) | ($0.00) | $0.00 | $0.00 | $0.00 | $0.00 |
| 41 | CUSTOMER SERVICES INVESTMENT | | $4.46 | $1.75 | $1.52 | $3.16 | $17.31 | $0.00 | ($0.00) | $0.00 |
| 42 | CUSTOMER METER INVESTMENT | | $2.32 | $0.70 | $0.67 | $0.84 | $9.23 | $69.37 | $0.00 | $0.00 |
| 43 | CUSTOMER ACCOUNT EXPENSE | | $22.69 | $22.37 | $22.25 | $23.11 | $24.31 | $24.24 | $21.35 | $20.61 |
| 44 | CUSTOMER SERVICE EXPENSES | | $0.81 | $0.61 | $0.60 | $0.69 | $1.38 | $33.05 | $1.10 | $0.45 |
| 45 | CUSTOMER OTHER | | $0.15 | ($0.08) | ($0.08) | ($0.14) | ($1.72) | ($14.72) | $202.56 | $6.60 |
| 46 | | | | | | | | | | |
| 47 | | | | | | | | | | |
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| 50 | | | | | | | | | | |

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| LINE NO. | DESCRIPTION | | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1 | **CLAIMED RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS** | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | **RATE OF RETURN** | | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% |
| 4 | | | | | | | | | | |
| 5 | **REVENUES REQUIRED** | | | | | | | | | |
| 6 | **DEMAND COMPONENTS** | 4,033,417 | 4,033,417 | 1,766,211 | 1,432,795 | 333,416 | 1,818,605 | 424,330 | 16,533 | 7,739 |
| 7 | AVAILABLE COMPONENT | | 0 | 0 | (0) | (0) | (0) | (0) | (0) | 0 |
| 8 | AVAILABLE COMPONENT | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 9 | DEMAND DISTRIBUTION COMPONENT | | 4,033,417 | 1,766,211 | 1,432,795 | 333,416 | 1,818,605 | 424,330 | 16,533 | 7,739 |
| 10 | DEMAND DISTRIBUTION HT | | 3,620,511 | 1,546,815 | 1,254,768 | 292,047 | 1,627,626 | 424,330 | 14,810 | 6,931 |
| 11 | DEMAND DISTRIBUTION PRIMARY | | 0 | 0 | (0) | (0) | (0) | 0 | 0 | 0 |
| 12 | DEMAND DISTRIBUTION SECONDARY | | 236,430 | 125,419 | 101,741 | 23,678 | 109,567 | (0) | 984 | 460 |
| 14 | DEMAND DISTRIBUTION TRANSFORMERS | | 176,476 | 93,976 | 76,286 | 17,691 | 81,413 | 0 | 739 | 347 |
| 13 | **ENERGY COMPONENTS** | 845,232 | 845,232 | 355,900 | 288,154 | 67,746 | 361,847 | 122,687 | 3,279 | 1,520 |
| 15 | ENERGY OTHER & PUR PWR | | 845,232 | 355,900 | 288,154 | 67,746 | 361,847 | 122,687 | 3,279 | 1,520 |
| 16 | **CUSTOMER COMPONENTS** | 4,626,335 | 4,626,335 | 3,285,300 | 2,816,140 | 469,159 | 965,156 | 14,266 | 236,636 | 124,977 |
| 17 | AVAILABLE COMPONENT | | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| 18 | CUSTOMER DISTR SECONDARY COMPONENT | | 2,225,377 | 1,666,053 | 1,434,278 | 231,774 | 351,701 | 0 | 145,102 | 62,521 |
| 19 | AVAILABLE COMPONENT | | 0 | 0 | (0) | (0) | (0) | 0 | 0 | 0 |
| 20 | CUSTOMER SERVICES INVESTMENT | | 408,390 | 199,703 | 162,088 | 37,615 | 208,687 | 0 | 0 | (0) |
| 21 | CUSTOMER METER INVESTMENT | | 186,485 | 64,066 | 55,138 | 8,927 | 113,679 | 8,740 | 0 | 0 |
| 22 | CUSTOMER ACCOUNT EXPENSE | | 1,656,243 | 1,336,531 | 1,149,234 | 187,297 | 290,503 | 2,951 | 3,612 | 22,646 |
| 23 | CUSTOMER SERVICE EXPENSES | | 53,915 | 33,124 | 27,907 | 5,217 | 16,246 | 3,953 | 165 | 426 |
| 24 | CUSTOMER OTHER | | 95,925 | (14,177) | (12,506) | (1,671) | (15,660) | (1,379) | 87,757 | 39,384 |
| 25 | **TOTAL COMPANY** | 9,504,985 | 9,504,985 | 5,407,411 | 4,537,090 | 870,321 | 3,145,608 | 561,282 | 256,448 | 134,236 |
| 26 | | | | | | | | | | |
| 27 | | | | | | | | | | (0) |
| 28 | | | | | | | | | | |
| 29 | | | | | | | | | | |
| 30 | Annual kWh Sales @ Meter | | 84,427,347 | 35,464,237 | 28,720,125 | 6,744,112 | 36,193,179 | 12,289,759 | 328,097 | 152,075 |
| 31 | Annual kW - Billed | | 145,539 | 0 | | | 112,368 | 33,172 | | |
| 32 | Number of Customer Bills | | 66,596 | 53,714 | 46,179 | 7,535 | 11,695 | 108 | 144 | 935 |
| 33 | | | | | | | | | | |
| 34 | kWh Use per Month per Customer | | 1,267.76 | 660.24 | 621.93 | 895.06 | 3,094.81 | 113,794.06 | 2,278.45 | 162.65 |
| 35 | | | | | | | 10 | 307 | | |
| 36 | | | | | | | | | | |
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**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| LINE NO. | DESCRIPTION | | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1 | **CLAIMED RATE OF RETURN SUMMARY SCHEDULE - UNIT COSTS** | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | **RATE OF RETURN** | | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% | 8.37% |
| 4 | | | | | | | | | | |
| 5 | **$/KWH** | | | | | | | | | |
| 6 | **DEMAND COMPONENTS** | $0.0478 | $0.0478 | $0.0498 | $0.0499 | $0.0494 | $0.0502 | $0.0345 | $0.0504 | $0.0509 |
| 7 | AVAILABLE COMPONENT | | $0.0000 | $0.0000 | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | $0.0000 |
| 8 | AVAILABLE COMPONENT | | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 | $0.0000 |
| 9 | DEMAND DISTRIBUTION COMPONENT | | $0.0478 | $0.0498 | $0.0499 | $0.0494 | $0.0502 | $0.0345 | $0.0504 | $0.0509 |
| 10 | DEMAND DISTRIBUTION HT | | $0.0429 | $0.0436 | $0.0437 | $0.0433 | $0.0450 | $0.0345 | $0.0451 | $0.0456 |
| 11 | DEMAND DISTRIBUTION PRIMARY | | $0.0000 | $0.0000 | ($0.0000) | ($0.0000) | ($0.0000) | $0.0000 | $0.0000 | $0.0000 |
| 12 | DEMAND DISTRIBUTION SECONDARY | | $0.0028 | $0.0035 | $0.0035 | $0.0035 | $0.0030 | $0.0000 | $0.0030 | $0.0030 |
| 14 | DEMAND DISTRIBUTION TRANSFORMERS | | $0.0021 | $0.0026 | $0.0027 | $0.0026 | $0.0022 | $0.0000 | $0.0023 | $0.0023 |
| 13 | **ENERGY COMPONENTS** | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 |
| 15 | ENERGY OTHER & PUR PWR | | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 | $0.0100 |
| 16 | **CUSTOMER COMPONENTS** | $0.0548 | $0.0548 | $0.0926 | $0.0981 | $0.0696 | $0.0267 | $0.0012 | $0.7212 | $0.8218 |
| 17 | AVAILABLE COMPONENT | | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) | ($0.0000) |
| 18 | CUSTOMER DISTR SECONDARY COMPONENT | | $0.0264 | $0.0470 | $0.0499 | $0.0344 | $0.0097 | $0.0000 | $0.4423 | $0.4111 |
| 19 | AVAILABLE COMPONENT | | $0.0000 | $0.0000 | ($0.0000) | ($0.0000) | ($0.0000) | $0.0000 | $0.0000 | $0.0000 |
| 20 | CUSTOMER SERVICES INVESTMENT | | $0.0048 | $0.0056 | $0.0056 | $0.0056 | $0.0058 | $0.0000 | $0.0000 | $0.0000 |
| 21 | CUSTOMER METER INVESTMENT | | $0.0022 | $0.0018 | $0.0019 | $0.0013 | $0.0031 | $0.0007 | $0.0000 | $0.0000 |
| 22 | CUSTOMER ACCOUNT EXPENSE | | $0.0196 | $0.0377 | $0.0400 | $0.0278 | $0.0080 | $0.0002 | $0.0110 | $0.1489 |
| 23 | CUSTOMER SERVICE EXPENSES | | $0.0006 | $0.0009 | $0.0010 | $0.0008 | $0.0004 | $0.0003 | $0.0005 | $0.0028 |
| 24 | CUSTOMER OTHER | | $0.0011 | ($0.0004) | ($0.0004) | ($0.0002) | ($0.0004) | ($0.0001) | $0.2675 | $0.2590 |
| 25 | **TOTAL COMPANY** | $0.1126 | $0.1126 | $0.1525 | $0.1580 | $0.1290 | $0.0869 | $0.0457 | $0.7816 | $0.8827 |
| 26 | | | | | | | | | | |
| 27 | **$/KW** | | | | | | | | | |
| 28 | **DEMAND COMPONENTS** | $27.71 | $27.71 | $0.00 | | | $16.18 | $12.79 | | |
| 29 | AVAILABLE COMPONENT | | $0.00 | $0.00 | | | ($0.00) | ($0.00) | | |
| 30 | AVAILABLE COMPONENT | | $0.00 | $0.00 | | | $0.00 | $0.00 | | |
| 31 | DEMAND DISTRIBUTION COMPONENT | | $27.71 | $0.00 | | | $16.18 | $12.79 | | |
| 32 | DEMAND DISTRIBUTION HT | | $24.88 | $0.00 | | | $14.48 | $12.79 | | |
| 33 | DEMAND DISTRIBUTION PRIMARY | | $0.00 | $0.00 | | | ($0.00) | $0.00 | | |
| 34 | DEMAND DISTRIBUTION SECONDARY | | $1.62 | $0.00 | | | $0.98 | $0.00 | | |
| 35 | | | | | | | | | | |
| 36 | **$/MONTH/CUSTOMER** | | | | | | | | | |
| 37 | **CUSTOMER COMPONENTS** | $69.47 | $69.47 | $61.16 | $60.98 | $62.27 | $82.53 | $132.09 | $1,643.30 | $133.67 |
| 38 | AVAILABLE COMPONENT | | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) | ($0.00) |
| 39 | CUSTOMER DISTR SECONDARY COMPONENT | | $33.42 | $31.02 | $31.06 | $30.76 | $30.07 | $0.00 | $1,007.65 | $66.87 |
| 40 | AVAILABLE COMPONENT | | $0.00 | $0.00 | ($0.00) | ($0.00) | ($0.00) | $0.00 | $0.00 | $0.00 |
| 41 | CUSTOMER SERVICES INVESTMENT | | $6.13 | $3.72 | $3.51 | $4.99 | $17.84 | $0.00 | $0.00 | $0.00 |
| 42 | CUSTOMER METER INVESTMENT | | $2.80 | $1.19 | $1.19 | $1.18 | $9.72 | $80.93 | $0.00 | $0.00 |
| 43 | CUSTOMER ACCOUNT EXPENSE | | $24.87 | $24.88 | $24.89 | $24.86 | $24.84 | $27.33 | $25.08 | $24.22 |
| 44 | CUSTOMER SERVICE EXPENSES | | $0.81 | $0.62 | $0.60 | $0.69 | $1.39 | $36.60 | $1.15 | $0.46 |
| 45 | CUSTOMER OTHER | | $1.44 | ($0.26) | ($0.27) | ($0.22) | ($1.34) | ($12.77) | $609.43 | $42.12 |
| 46 | | | | | | | | | | |
| 47 | | | | | | | | | | |
| 48 | Total of Lines 39, 41 & 42 | | $42.35 | $35.93 | $35.76 | $36.94 | $57.64 | $80.93 | $1,007.65 | $66.87 |
| 49 | | | | | | | | | | |
| 50 | | | | | | | | | | |

The listing of all external allocation factors shown are in pages 14 to 15 of the Allocation Factor Table and pages 20 to 21 of the Ratio Table of Exhibit E-6, Schedule PMN-4-E of the Pike County Light & Power Company embedded electric cost of service study.

**External Allocators – Demand Related, Page 20**

1. DDISPHT – Demand Distribution Primary High Tension Allocator. High Tension allocation factor is based on the Non-coincident maximum high tension class demand at generating stations. Allocator Ratio is on Page 20, line 14.

2. DDISTPOL – Demand Distribution Primary Overhead Lines Allocator. Low Tension Overhead allocation factor was based on the associated book costs using the average of non-coincident maximum 60 cycle class demands and individual customer billing demands for summer and winter seasons. Allocator Ratio is on Page 20, line 15.

3. DDISTPUL – Demand Distribution Primary Underground Lines Allocator. Low Tension Underground allocation factor was based on the associated book costs using the average of non-coincident maximum 60 cycle class demands and individual customer billing demands for summer and winter seasons. Allocator Ratio is on Page 20, line 16.

4. DDISTSLT – Demand Distribution Line Transformers. Allocator Ratio is on Page 20, line 20.

**External Allocators – Energy Related, Page 20**

5. ENERGY1 – Commodity Allocator
Energy at Delivery (kWh). Allocator Ratio is on Page 20, line 26.

6. ENERGY2 – Commodity Allocator
Energy at Meter (kWh Sales). Annual kilowatt-hour sales for Pike's service classes. Allocator Ratio is on Page 20, line 27.

**External Allocators – Customer Related, Page 21**

7. CDISTSOLC – Acct 364 & 366 - Poles, Towers, Fixtures & Conductors – Customer Distribution Secondary Function.
This allocator represents the annual number of customers by rate class. Allocation Ratio is on Page 21, line 57.

8. CDISTSULC – Acct 365 & 367 - Conductors & Devices - Customer Distribution Secondary Function.
This allocator represents the annual number of customers by rate class. Allocation Ratio is on Page 21, line 58.

9. CDISTSLT - Acct 368 – Customer Distribution Secondary Function. Line Transformers. Allocation Ratio is on Page 21, line 59.

10. CUSTSERV – Acct 369 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 21, line 61.

11. CUSTMTR – Acct 370 Meter Investment – 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 21, line 62.

12. CUSTLTG - Acct 373 – Street Lighting & Signal Systems – Customer Other Function.
This allocator represents the assignment of plant to the lighting classes. Allocation Ratio is on Page 21, line 64

13. CUSTDEP - Customer Deposits – Customer Other Function
This allocator represents the assignment of customer deposits to the Residential and Small General customer classes based on the number of customers. See Workpapers for detail. Allocation Ratio is on Page 21, line 66.

14. CUSTMTRDG – Acct 902 Meter Reading Expense – Customer Accounts Expense Function
This allocator was based on the number of meters by rate class with a weighting factor applied to daily read meters. Allocation Ratio is on Page 21, line 68.

15. 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 21, line 69.

**External Allocators – Customer Related, Page 21, continued**

16. 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 21, line 77) and a 50% weighting on the total annual kWh sales at the meter (Page 20, line 27). Allocation Ratio is on Page 21, line 71.

17. 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 21, line 72.

18. 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 21, line 73.

19. 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 21, line 74.

**External Allocators – Revenue Related, Page 267**

16. EXP_904 – Account 904 – Uncollectible Accounts
This allocator is a direct assignment allocator that was developed using write-offs by class. Allocation Ratio is on Page 26, line 15.

17. REV_487 – Account 487 – Late Payment Charges
This allocator is a direct assignment allocator that was developed using the forfeited discounts by class. Allocation Ratio is on Page 26, line 32.

**Pike County Light & Power Company**
**Electric Class Cost of Service Study**
**12 Months Ended September 30, 2024**

| SCH NO. | LINE NO. | DESCRIPTION | ALLOCATION BASIS | TOTAL ELECTRIC COMPANY | Total Residential | Residential SC1 | Residential Space/Water Htg SC1 | Small Commercial & Industrial - Sec SC2-S | Large Commercial & Industrial - Pri SC2-P | Municipal Street Lighting SC3 | Private Lighting SC4 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (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 | **OPERATING INCOME (RETURN) @ PRESENT RATES** | | 2,145,215 | 728,419 | 547,523 | 180,896 | 1,186,953 | 192,600 | 34,542 | 2,701 |
| SUM | 4 | **LESS Historical and Future Year Differences:** | | | | | | | | | |
| SUM | 5 | Retail Sales Revenue | CLAIMREV | 2,169,043 | 1,233,974 | 1,035,367 | 198,608 | 717,830 | 128,085 | 58,522 | 30,633 |
| SUM | 6 | 450-Late Payment Charges | EXP_904 | (17,100) | (15,848) | (12,219) | (3,629) | (1,252) | 0 | 0 | 0 |
| SUM | 7 | 454-Rent from Electric Property | PLT_364 | 171,900 | 89,992 | 74,825 | 15,167 | 63,013 | 13,360 | 3,868 | 1,667 |
| SUM | 8 | 456-Other Electric Revenues (Prov for FIT Refund) | CLAIMREV | (3,000) | (1,707) | (1,432) | (275) | (993) | (177) | (81) | (42) |
| SUM | 9 | **PLUS Historical and Future Year Differences:** | | | | | | | | | |
| SUM | 10 | Purchased Power | ENERGY1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SUM | 11 | Other Power Supply Expenses (Base Rate) | ENERGY1 | 36,700 | 15,419 | 12,486 | 2,932 | 15,735 | 5,337 | 143 | 66 |
| SUM | 12 | O&M Expense - Labor Related | LABOR | 123,600 | 83,572 | 71,011 | 12,561 | 32,612 | 4,528 | 1,423 | 1,465 |
| SUM | 13 | O&M Expense - Distribution Plant Related | DISTPLT | 56,500 | 29,624 | 24,696 | 4,929 | 20,402 | 3,321 | 2,197 | 956 |
| SUM | 14 | O&M Expense - 904-Uncollectible Accounts | EXP_904 | (21,508) | (19,934) | (15,369) | (4,564) | (1,575) | 0 | 0 | 0 |
| SUM | 15 | O&M Expense - Regulatory Commission/SBC Exp | CLAIMREV | 39,800 | 22,642 | 18,998 | 3,644 | 13,172 | 2,350 | 1,074 | 562 |
| SUM | 16 | Depreciation Expense | TOTPLT | 261,300 | 140,912 | 117,749 | 23,164 | 91,852 | 14,789 | 9,455 | 4,292 |
| SUM | 17 | TOIT - Base Payroll Taxes | LABOR | (80,556) | (54,468) | (46,281) | (8,186) | (21,255) | (2,951) | (927) | (955) |
| SUM | 18 | TOIT - PA Property Tax | DGPLT | (1,270) | (685) | (572) | (113) | (446) | (72) | (46) | (21) |
| SUM | 19 | TOIT - Gross Receipt Tax | CLAIMREV | 474,747 | 270,085 | 226,615 | 43,470 | 157,114 | 28,034 | 12,809 | 6,705 |
| SUM | 20 | State Income Taxes | CLAIMREV | 85,540 | 49,912 | 41,929 | 7,983 | 27,553 | 5,217 | 1,812 | 1,046 |
| SUM | 21 | Federal Income Taxes | CLAIMREV | 206,861 | 120,556 | 101,266 | 19,291 | 66,732 | 12,604 | 4,428 | 2,542 |
| SUM | 22 | **OPERATING INCOME @ PRESENT RATES WITH DIFFERENCES** | | 3,284,343 | 1,377,193 | 1,091,536 | 285,657 | 1,563,656 | 260,709 | 64,484 | 18,300 |
| SUM | 23 | Operating Income Before Taxes (adjustments only) | | 1,431,530 | 819,243 | 687,208 | 132,035 | 470,987 | 85,930 | 36,183 | 19,188 |
| SUM | 24 | **RATE BASE** | SCH SUM, LN 28 | 34,027,461 | 18,342,295 | 15,313,802 | 3,028,493 | 11,892,578 | 1,945,602 | 1,272,706 | 574,279 |
| SUM | 25 | **Historical and Future Year Difference Adjustments:** | | | | | | | | | |
| SUM | 26 | Gas Utility Plant & Reserves Adjustments | TOTPLT | 5,634,539 | 3,038,560 | 2,539,072 | 499,488 | 1,980,648 | 318,912 | 203,876 | 92,543 |
| SUM | 27 | Additions: | | | | | | | | | |
| SUM | 28 | Cash Working Capital | OMXPP | (478,200) | (306,917) | (259,147) | (47,769) | (136,808) | (21,824) | (7,142) | (5,509) |
| SUM | 29 | Materials and Supplies | TOTPLT | 32,700 | 17,634 | 14,735 | 2,899 | 11,495 | 1,851 | 1,183 | 537 |
| SUM | 30 | Prepayments | TOTPLT | (100) | (54) | (45) | (9) | (35) | (6) | (4) | (2) |
| SUM | 31 | Deferred Debits (Net of Tax) | TOTPLT | (32,400) | (17,472) | (14,600) | (2,872) | (11,389) | (1,834) | (1,172) | (532) |
| SUM | 32 | Deductions: | | | | | | | | | |
| SUM | 33 | Deferred Credits (Net of Tax) | TOTPLT | 12,700 | 6,849 | 5,723 | 1,126 | 4,464 | 719 | 460 | 209 |
| SUM | 34 | Customer Deposits | CUSTDEP | 3,500 | 1,533 | 1,349 | 184 | 1,808 | 159 | 0 | 0 |
| SUM | 35 | Deferred Income Taxes and Credits | CLAIMREV | 134,300 | 76,404 | 64,106 | 12,297 | 44,446 | 7,931 | 3,623 | 1,897 |
| SUM | 36 | **RATE BASE WITH ADJUSTMENTS** | | 39,033,500 | 20,989,261 | 17,522,639 | 3,466,622 | 13,685,770 | 2,233,894 | 1,465,364 | 659,210 |
| SUM | 37 | | | | | | | | | | |
| SUM | 38 | **DEVELOPMENT OF RETURN (RATE BASE * 8.37% ROR)** | | 3,267,197 | 1,756,851 | 1,466,687 | 290,165 | 1,145,532 | 186,982 | 122,654 | 55,177 |
| SUM | 39 | **PLUS OPERATING EXPENSES** | | | | | | | | | |
| SUM | 40 | Other Power Supply Exp | | 771,568 | 324,154 | 262,511 | 61,643 | 330,817 | 112,208 | 2,999 | 1,390 |
| SUM | 41 | Operation and Maintenance Expense | | 3,429,161 | 2,190,197 | 1,850,972 | 339,225 | 987,698 | 158,197 | 52,822 | 40,247 |
| SUM | 42 | Depreciation and Amortization Expense | | 1,358,250 | 718,280 | 600,376 | 117,904 | 491,447 | 72,789 | 52,221 | 23,513 |
| SUM | 43 | Taxes Other Than Income Taxes | | 633,700 | 397,959 | 339,059 | 58,900 | 171,723 | 30,187 | 21,719 | 12,112 |
| SUM | 44 | State Income Taxes | | 49,781 | 26,344 | 21,984 | 4,361 | 17,811 | 2,864 | 1,917 | 845 |
| SUM | 45 | Federal Income Taxes | | 120,385 | 63,563 | 53,031 | 10,531 | 43,172 | 6,914 | 4,681 | 2,056 |
| SUM | 46 | **TOTAL OPERATING EXPENSES** | | 6,362,846 | 3,396,344 | 3,127,934 | 592,564 | 2,042,668 | 383,158 | 136,358 | 80,164 |
| SUM | 47 | **EQUALS TOTAL COST OF SERVICE** | | 9,630,042 | 5,477,349 | 4,594,620 | 882,729 | 3,188,200 | 570,140 | 259,012 | 135,341 |
| SUM | 48 | **LESS: Other Operating Revenues** | | 125,058 | 69,938 | 57,530 | 12,408 | 42,591 | 8,858 | 2,565 | 1,105 |
| SUM | 49 | **BASE RATE SALES @ EQUALIZED ROR 8.37%** | | 9,504,985 | 5,407,411 | 4,537,090 | 870,321 | 3,145,608 | 561,282 | 256,448 | 134,236 |
| SUM | 50 | **BASE RATE SALES REVENUE INCREASE** | | 2,143,900 | 1,790,692 | 1,585,475 | 205,217 | 104,706 | 19,974 | 143,820 | 84,708 |

**Pike County Light & Power**
**Electric 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 | Total Current Base Sales Revenue | | Total Sales Revenue | Increase Target Base Revenue Increase @ Uniform ROR 8.37% | Revenue Increase Capped at 1.29% of Uniform ROR 8.37% 10.81% | Capped Revenue Increase | Total To Redistribute | Redistributed Capped Revenue |
|---|---|---|---|---|---|---|---|---|---|
| | ( A ) | ( B ) | ( C ) | (D ) | ( E ) | ( F ) | ( G ) | (H) | (I) |
| | | | | (col B + col C) | (2) | | | (total col E - total col G) | |
| 1 | **Rate Schedule:** | | | | | | | | |
| 2 | SC-1 Residential 301 & X3E | $2,951,615 | | $2,951,615 | $1,585,475 | $319,070 | $945,617 | | |
| 3 | SC-1 Residential Space & Water Heating | $665,104 | | $665,104 | $205,217 | $71,898 | $213,081 | | |
| 4 | SC-2 Small Comm & Ind Secondary | $3,040,902 | | $3,040,902 | $104,706 | $328,722 | | | $792,252 |
| 5 | SC-2 Large Comm & Ind Primary 502,702,X5D,X7D | $541,308 | | $541,308 | $19,974 | $58,515 | | | $141,000 |
| 6 | Municipal Street Lighting | $112,628 | | $112,628 | $143,820 | $12,175 | $36,083 | | |
| 7 | Private Lighting | $49,527 | | $49,527 | $84,708 | $5,354 | $15,867 | | |
| 11 | **Total** | $7,361,084 | $0 | $7,361,084 | **$2,143,900** | | $1,210,648 | $933,252 | $933,252 |
| 12 | | $7,361,084 | | | | | | | |
| 13 | | | | | | 29.1% | 32.0% | Res Increase | |
| 14 | | | | | | Base Increase | 32.0% | Ltg Increase | |
| 15 | **Notes** | | | | | | | | |
| 16 | (1) Source for columns B and C is file | | | | | | | | |
| 17 | Pike Electric Revenue Proof 9-30-24 Test Year Rev 11-19-24.xlsx | | | | | | | | |
| 18 | (2) Source for column E is Exhibit E-6, Sch PMN-3-E, line 19. | | | | | | | | |
| 19 | (3) Overall Increase is based on col D base sales revenue | | | | | | | | |
| 20 | calculated using historical volumes & demands and col L | | | | | | | | |
| 21 | proposed base revenues are calculated using test year volumes. | | | | | | | | |
| 22 | | | | | | | | | |

**Pike County Light & Power**
**Electric 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 | Target Base Revenue Proposed Increase | Target Proposed Base Revenue | Proposed Total Base Sales Revenue | Base Sales Percent Increase | Overall Increase |
|---|---|---|---|---|---|---|
| | ( A ) | (J) | (K) | (L) | (M) | (N) |
| | | (col G + col I) | (col B + col J) | | | |
| 1 | **Rate Schedule:** | | | | | |
| 2 | SC-1 Residential 301 & X3E | $945,617 | $3,897,232 | $3,896,239 | 32.0% | 32.0% |
| 3 | SC-1 Residential Space & Water Heating | $213,081 | $878,185 | $879,184 | 32.2% | 32.2% |
| 4 | SC-2 Small Comm & Ind Secondary | $792,252 | $3,833,154 | $3,833,137 | 26.1% | 26.1% |
| 5 | SC-2 Large Comm & Ind Primary 502,702,X5D,X7D | $141,000 | $682,308 | $682,313 | 26.0% | 26.0% |
| 6 | Municipal Street Lighting | $36,083 | $148,711 | $148,711 | 32.0% | 32.0% |
| 7 | Private Lighting | $15,867 | $65,395 | $65,395 | 32.0% | 32.0% |
| 11 | **Total** | $2,143,900 | $9,504,985 | $9,504,979 | 29.1% | 29.1% |
| 12 | | | | -$6 diff | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | **Notes** | | | | | |
| 16 | (1) Source for columns B and C is file | | | | | |
| 17 | Pike Electric Revenue Proof 9-30-24 Test Year Rev 11-19-24.xlsx | | | | | |
| 18 | (2) Source for column E is Exhibit E-6, Sch PMN-3-E, line 19. | | | | | |
| 19 | (3) Overall Increase is based on col D base sales revenue | | | | | |
| 20 | calculated using historical volumes & demands and col L | | | | | |
| 21 | proposed base revenues are calculated using test year volumes. | | | | | |
| 22 | | | | | | |

**Pike County Light & Power**
**Electric 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**

**WITHOUT PURCHASED POWER COSTS**

| | Present Rates | | | | Proposed Rates | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Schedule & Cost Component** | **Quantity** | **Units** | **Base Margin Rate** | **Revenue** | **Quantity** | **Units** | **Rate** | **Base Margin Revenue** | **Change** |
| | **SC-1 Residential 301 & X3E** | | | | **SC-1 Residential 301 & X3E** | | | | |
| **SC-1 Residential 301 & X3E** | | | | | | | | | |
| Customer Charge | 44,403 | Cust | $8.80 | $ 390,746 | 46,179 | Cust | $10.80 | $ 498,734 | |
| Energy Charge - All kWh | 27,615,505 | kWh | $0.092733 | $ 2,560,869 | 28,720,125 | kWh | $0.118297 | $ 3,397,505 | |
| **Total Revenues** | | | | **$ 2,951,615** | | | | **$ 3,896,239** | **32.0%** |
| **Monthly Use Per Customer (1)** | | | | | | | 622 | $ 3,897,232 | Target |
| **Monthly $ per Customers @ Proposed Equalized ROR (2)** | | | | | | | $60.98 | | |
| | **SC-1 Residential Space & Water Heating** | | | | **SC-1 Residential Space & Water Heating** | | | | |
| **SC-1 Residential Space & Water Heating (601,701,801,X6E,X7E,X8E)** | | | | | | | | | |
| Customer Charge | 7,245 | Cust | $8.80 | $ 63,756 | 7,535 | Cust | $10.80 | $ 81,376 | |
| Energy Charge - All kWh | 6,484,723 | kWh | $0.092733 | 601,348 | 6,744,112 | kWh | $0.118297 | $ 797,808 | |
| **Total Revenues** | | | | **$ 665,104** | | | | **$ 879,184** | **32.2%** |
| **Monthly Use Per Customer (1)** | | | | | | | 895 | $ 878,185 | Target |
| **Monthly $ per Customers @ Proposed Equalized ROR (2)** | | | | | | | $62.27 | | |

**Pike County Light & Power**
**Electric 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**

**WITHOUT PURCHASED POWER COSTS**

| | Present Rates | | | | Proposed Rates | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Schedule & Cost Component** | **Quantity** | **Units** | **Base Margin Rate** | **Revenue** | **Quantity** | **Units** | **Rate** | **Base Margin Revenue** | **Change** |
| | **SC-2 Small Comm & Ind Secondary** | | | | **SC-2 Small Comm & Ind Secondary** | | | | |
| **SC-2 Small Comm & Ind Secondary** | | | | | | | | | |
| **(102,402,802,902,X1D,X4D,X8D,X9D)** | | | | | | | | | |
| Customer Charge (Excl 402 &X4D) | 11,113 | Cust | $17.26 | $ 191,810 | 11,558 | Cust | $21.50 | $ 248,487 | |
| Customer Charge (402 &X4D) (min charge) | 132 | Cust | $17.26 | 2,278 | 137 | Cust | $21.50 | 2,952 | |
| | 11,245 | | | 194,089 | 11,695 | | | | |
| kWh Volume Demand Meters | | | | | | | | | |
| First 100 Hours Use | 10,451,663 | kWh | $0.079086 | 826,580 | 10,869,729 | kWh | $0.094594 | 1,028,211 | |
| Next 100 Hours Use | 8,575,995 | kWh | $0.065488 | 561,625 | 8,919,034 | kWh | $0.078330 | 698,628 | |
| Over 200 Hours Use | 14,387,514 | kWh | $0.064263 | 924,585 | 14,963,014 | kWh | $0.076864 | 1,150,117 | |
| Total Hours Use kWh | 33,415,171 | | | 2,312,790 | 34,751,778 | | | 2,876,956 | |
| Ener Spc Htg KWH 402 & X4D | 525,394 | kWh | $0.066731 | 35,060 | 546,410 | kWh | $0.079824 | 43,617 | |
| Ener No Demand or Unmetered | | | | | | | | | |
| Rate Code 802,902,X8D,X9D | 860,569 | kWh | $0.094726 | 81,518 | 894,992 | kWh | $0.113302 | 101,404 | |
| | 34,801,134 | | | 2,429,368 | 36,193,179 | | | | |
| Demand Charge All kW | | | | | | | | | |
| First 5 kW | 25,894 | kW | $1.21 | 31,331 | 26,930 | kW | $1.56 | 42,010 | |
| Over 5 kW | 82,152 | kW | $4.70 | 386,114 | 85,438 | kW | $6.06 | 517,712 | |
| | 108,046 | | | 417,445 | 112,368 | | | 559,722 | |
| **Total Revenues** | | | | **$ 3,040,902** | | | | **$ 3,833,137** | **26.1%** |
| **Monthly Use Per Customer (1)** | | | | | | | 3,095 | $ 3,833,154 | Target |
| **Monthly $ per Customers @ Proposed Equalized ROR (2)** | | | | | | | $82.53 | | |

| | Present Rates | | | | Proposed Rates | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **SC-2 Large Comm & Ind Primary 502,702,X5D,X7D** | | | | **SC-2 Large Comm & Ind Primary 502,702,X5D,X7D** | | | | |
| **SC-2 Large Comm & Ind Primary** | | | | | | | | | |
| Customer Charge | 108 | Cust | $140.00 | $ 15,120 | 108 | Cust | $175.00 | $ 18,900 | |
| Demand Charge | 31,861 | kW | $10.60 | 337,725 | 33,172 | kW | $13.00 | 431,235 | |
| Energy Charge | 11,804,030 | kWh | $0.015966 | 188,463 | 12,289,759 | kWh | $0.018892 | 232,178 | |
| **Total Revenues** | | | | **$ 541,308** | | | | **$ 682,313** | **26.0%** |
| **Monthly Use Per Customer (1)** | | | | | | | 113,794 | $ 682,308 | Target |
| **Monthly $ per Customers @ Proposed Equalized ROR (2)** | | | | | | | $1,643.30 | | |
| **Municipal Street Lighting** | | | | **$ 112,628** | | | | **$ 148,711** | |
| **Private Lighting** | | | | **$ 49,527** | | | | **$ 65,395** | |

**Pike County Light & Power**
**Electric 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**

**WITHOUT PURCHASED POWER COSTS**

| | Schedule & Cost Component | Present Rates Quantity | Present Rates Units | Present Rates Base Margin Rate | Present Rates Revenue | Proposed Rates Quantity | Proposed Rates Units | Proposed Rates Rate | Proposed Rates Base Margin Revenue | Change |
|---|---|---|---|---|---|---|---|---|---|---|
| 74 | | | | | | | | | | |
| 75 | *TOTAL SYSTEM REVENUES* | | | | *$ 7,361,084* | | | | *$ 9,504,979* | *29.1%* |
| 76 | | | | | | | | | | |

77 ***Notes:***
78 (1) Source for Use per Customer is Exhibit E-6, Schedule PMN-5-E, page 3, line 34.
79 (2) Source for $/Month/Customer is Schedule Exhibit E-6, Schedule PMN-6-E, page 4, line 37.
80

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

**PIKE COUNTY LIGHT AND POWER COMPANY**

Present and Proposed Rates

| Present SC1 | | | Proposed SC1 | | |
|---|---|---|---|---|---|
| Customer Charge | $8.80 | / Month | Customer Charge | $10.80 | / Month |
| Delivery All kWh | 9.2733 | ¢/kWh | Delivery All kWh | 11.8297 | ¢/kWh |
| Electric Supply | 8.6475 | ¢/kWh | Electric Supply | 8.6475 | ¢/kWh |
| Electric Supply Adjustment | 0.1452 | ¢/kWh | Electric Supply Adjustment | 0.1452 | ¢/kWh |
| **All kWh** | 18.0660 | ¢/kWh | All kWh | 20.6224 | ¢/kWh |
| Plus: Res System Benefit Charge | 0.0390 | ¢/kWh | Plus: Res System Benefit Charge | 0.0390 | ¢/kWh |
| Plus: Delivery State Tax Adjustment | -0.1600% | | Plus: Delivery State Tax Adjustment | -0.2700% | |
| Plus: DISC | 5.0000% | | Plus: DISC | 0.0000% | |
| Minimum Charge: | $8.80 | / Month | Minimum Charge: | $10.80 | / Month |

# PIKE COUNTY LIGHT AND POWER COMPANY

Present and Proposed Rates

| Present SC2 - Secondary Demand | | | Proposed SC2 - Secondary Demand | | |
|---|---|---|---|---|---|
| Customer Charge | $17.26 | / Month | Customer Charge | $21.50 | / Month |
| First 5 kW | $1.21 | /kW | First 5 kW | $1.56 | /kW |
| Over 5 kW | $4.70 | /kW | Over 5 kW | $6.06 | /kW |
| Hours Use of Billing Demand | | | First 100 HU | | |
| First 100 Hours Use | 7.9086 | ¢/kWh | First 100 Hours Use | 9.4594 | ¢/kWh |
| Next 100 Hours Use | 6.5488 | ¢/kWh | Next 100 Hours Use | 7.8330 | ¢/kWh |
| Over 200 Hours Use | 6.4263 | ¢/kWh | Over 200 Hours Use | 7.6864 | ¢/kWh |
| Electric Supply | 8.2263 | ¢/kWh | Electric Supply | 8.2263 | ¢/kWh |
| Electric Supply Adjustment | 0.2934 | ¢/kWh | Electric Supply Adjustment | 0.2934 | ¢/kWh |
| Plus: Delivery State Tax Adjustment | -0.1600% | | Plus: Delivery State Tax Adjustment | -0.2700% | |
| Plus: DISC | 5.0000% | | Plus: DISC | 0.0000% | |
| Sales Tax on Total Bill | 6.0000% | | Sales Tax on Total Bill | 6.0000% | |
| Minimum Charge: | $17.26 | / Month | Minimum Charge: | $21.50 | / Month |

| Present SC2 - Secondary Non-Demand & Non Metered | | | Proposed SC2 - Secondary Non-Demand & Non Metered | | |
|---|---|---|---|---|---|
| Customer Charge | $17.26 | / Month | Customer Charge | $21.50 | / Month |
| All kWh | 9.4726 | ¢/kWh | All kWh | 11.3302 | ¢/kWh |
| Separately Metered Space Heating: | | | Separately Metered Space Heating: | | |
| All kWh | 6.6731 | ¢/kWh | All kWh | 7.9824 | ¢/kWh |
| Electric Supply | 8.2263 | ¢/kWh | Electric Supply | 8.2263 | ¢/kWh |
| Electric Supply Adjustment | 0.2934 | ¢/kWh | Electric Supply Adjustment | 0.2934 | ¢/kWh |
| Plus: Delivery State Tax Adjustment | -0.1600% | | Plus: Delivery State Tax Adjustment | -0.2700% | |
| Plus: DISC | 5.0000% | | Plus: DISC | 0.0000% | |
| Sales Tax on Total Bill | 6.0000% | | Sales Tax on Total Bill | 6.0000% | |
| Min Chrg Non Demand & Non Meter | $17.26 | / Month | Min Chrg Non Demand & Non Meter | $21.50 | / Month |

**PIKE COUNTY LIGHT AND POWER COMPANY**

Present and Proposed Rates

| Present SC2 - Primary | | | Proposed SC2 - Primary | | |
|---|---|---|---|---|---|
| Customer Charge | $140.00 | / Month | Customer Charge | $175.00 | / Month |
| All kW | $10.60 | /kW | All kW | $13.00 | /kW |
| All kWh | 1.5966 | ¢/kWh | All kWh | 1.8892 | ¢/kWh |
| Electric Supply | 7.5922 | ¢/kWh | Electric Supply | 7.5922 | ¢/kWh |
| Electric Supply Adjustment | 0.1275 | ¢/kWh | Electric Supply Adjustment | 0.1275 | ¢/kWh |
| Plus: Delivery State Tax Adjustment | -0.1600% | | Plus: Delivery State Tax Adjustment | -0.2700% | |
| Plus: DISC | 5.0000% | | Plus: DISC | 0.0000% | |
| Sales Tax on Total Bill excl Exempt | 6.0000% | | Sales Tax on Total Bill excl Exempt | 6.0000% | |
| Minimum Charge: | $140.00 | / Month | Minimum Charge: | $175.00 | / Month |

**PIKE COUNTY LIGHT AND POWER COMPANY**

Present and Proposed Rates

| Present SC3 (Municipal Street Lighting - Monthly) | | | | | Proposed SC3 (Municipal Street Lighting - Monthly) | | | |
|---|---|---|---|---|---|---|---|---|
| Lumens | Luminaire Type | Charge | | | Lumens | Luminaire Type | Charge | |
| Street Lighting Luminaries: | | | | | Street Lighting Luminaries: | | | |
| 5,800 | Sodium Vapor | $24.73 | | | 5,800 | Sodium Vapor | $32.65 | |
| 9,500 | Sodium Vapor | 27.09 | | | 9,500 | Sodium Vapor | $35.77 | |
| 16,000 | Sodium Vapor | 30.76 | | | 16,000 | Sodium Vapor | $40.61 | |
| 27,500 | Sodium Vapor | 39.49 | | | 27,500 | Sodium Vapor | $52.14 | |
| 46,000 | Sodium Vapor | 51.95 | | | 46,000 | Sodium Vapor | $68.59 | |
| 3,900 | LED | 28.65 | | | 3,900 | LED | $37.83 | |
| 5,000 | LED | 28.74 | | | 5,000 | LED | $37.95 | |
| 5,890 | LED | 29.16 | | | 5,890 | LED | $38.50 | |
| 9,365 | LED | 35.79 | | | 9,365 | LED | $47.26 | |
| 16,000 | LED | 30.52 | | | 16,000 | LED | $40.30 | |
| 22,000 | LED | 31.11 | | | 22,000 | LED | $41.08 | |
| Flood Lighting Luminaries: | | | | | Flood Lighting Luminaries: | | | |
| 14,500 | LED | 28.91 | | | 14,500 | LED | $38.17 | |
| 28,700 | LED | 31.36 | | | 28,700 | LED | $41.41 | |

**The following luminaires will no longer be installed. Charges are for existing installations only:**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 46,000 | Sodium Vapor | 43.60 | | | 46,000 | Sodium Vapor | $57.57 | |
| 27,500 | Sodium Vapor | 39.46 | | | 27,500 | Sodium Vapor | $52.10 | |
| 4,000 | Mercury Vapor | 17.54 | | | 4,000 | Mercury Vapor | $23.16 | |
| 7,900 | Mercury Vapor | 21.25 | | | 7,900 | Mercury Vapor | $28.06 | |
| 12,000 | Mercury Vapor | 27.68 | | | 12,000 | Mercury Vapor | $36.55 | |
| MUNI OVERHEAD - 15 FOOT POLE | | 0.60 | | | MUNI OVERHEAD - 15 FOOT POLE | | $0.79 | |
| Underground Service Company Owns & Maintains | | 274.68 | | | Underground Service Company Owns & Maintains | | $362.68 | |
| Underground Service Customer Owns & Maintains | | 66.48 | | | Underground Service Customer Owns & Maintains | | $87.78 | |
| Electric Supply | 7.9033 | ¢/kWh | | | Electric Supply | 7.9033 | ¢/kWh | |
| Electric Supply Adjustment | 1.1961 | ¢/kWh | | | Electric Supply Adjustment | 1.1961 | ¢/kWh | |
| Plus: Delivery State Tax Adjustment | -0.1600% | | | | Plus: Delivery State Tax Adjustment | -0.2700% | | |
| Plus: DISC | 5.0000% | | | | Plus: DISC | 0.0000% | | |
| Sales Tax on Total Bill excl Exempt | 6.0000% | | | | Sales Tax on Total Bill excl Exempt | 6.0000% | | |

**PIKE COUNTY LIGHT AND POWER COMPANY**

Present and Proposed Rates

| Present SC4 (Private Area Lighting - Monthly) | | | Proposed SC4 (Private Area Lighting - Monthly) | | |
|---|---|---|---|---|---|
| Lumens | Luminaire Type | Charge | Lumens | Luminaire Type | Charge |
| Private Lighting Luminaries | | | Private Lighting Luminaries | | |
| 5,800 | Sodium Vapor | $24.73 | 5,800 | Sodium Vapor | $32.65 |
| 16,000 | Sodium Vapor | 30.76 | 16,000 | Sodium Vapor | $40.61 |
| 3,900 | LED | 32.47 | 3,900 | LED | $42.87 |
| 5,000 | LED | 32.56 | 5,000 | LED | $42.99 |
| 7,250 | LED | 32.97 | 7,250 | LED | $43.53 |
| 9,365 | LED | 33.66 | 9,365 | LED | $44.44 |
| Flood Light Luminaries | | | | | |
| 14,500 | LED | 35.31 | 14,500 | LED | $46.62 |
| 28,700 | LED | 37.76 | 28,700 | LED | $49.86 |
| **The following luminaires will no longer be installed. Charges are for existing installations only:** | | | | | |
| 4,000 | Mercury Vapor | 13.66 | 4,000 | Mercury Vapor | $18.04 |
| 4,000 | Mercury Vapor | 12.26 | 4,000 | Mercury Vapor | $16.19 |
| 7,900 | Mercury Vapor | 16.55 | 7,900 | Mercury Vapor | $21.85 |
| 7,900 | Mercury Vapor | 15.10 | 7,900 | Mercury Vapor | $19.94 |
| 12,000 | Mercury Vapor | 21.56 | 12,000 | Mercury Vapor | $28.47 |
| 22,500 | Mercury Vapor | 28.02 | 22,500 | Mercury Vapor | $37.00 |
| 27,500 | Sodium Vapor | 39.46 | 27,500 | Sodium Vapor | $52.10 |
| 46,000 | Sodium Vapor | 43.60 | 46,000 | Sodium Vapor | $57.57 |
| PRIVATE OVERHEAD - 15 FOOT POLE | | 0.60 | PRIVATE OVERHEAD - 15 FOOT POLE | | $0.79 |
| Electric Supply | 7.9316 ¢/kWh | | Electric Supply | 7.9316 ¢/kWh | |
| Electric Supply Adjustment | 1.8760 ¢/kWh | | Electric Supply Adjustment | 1.8760 ¢/kWh | |
| Plus: Delivery State Tax Adjustment | -0.1600% | | Plus: Delivery State Tax Adjustment | -0.2700% | |
| Plus: DISC | 5.0000% | | Plus: DISC | 0.0000% | |
| Sales Tax on Total Bill excl Exempt | 6.0000% | | Sales Tax on Total Bill excl Exempt | 6.0000% | |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC1 Residential***

| Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|
| 0 | $9.23 | $10.77 | $1.54 | 16.7 | $0.00 | 16.7 |
| 50 | 14.11 | $16.69 | 2.58 | 18.3 | $4.40 | 14.0 |
| 100 | 18.99 | $22.61 | 3.62 | 19.1 | $8.79 | 13.0 |
| 200 | $28.75 | $34.44 | $5.69 | 19.8 | $17.59 | 12.3 |
| 250 | 33.63 | $40.36 | 6.73 | 20.0 | $21.98 | 12.1 |
| 300 | 38.51 | $46.28 | 7.77 | 20.2 | $26.38 | 12.0 |
| 400 | $48.28 | $58.12 | $9.84 | 20.4 | $35.17 | 11.8 |
| 500 | 58.04 | $69.95 | 11.91 | 20.5 | $43.96 | 11.7 |
| 750 | 82.45 | $99.55 | 17.10 | 20.7 | $65.95 | 11.5 |
| 1,000 | $106.86 | $129.14 | $22.28 | 20.9 | $87.93 | 11.4 |
| 1,500 | 155.67 | $188.32 | 32.65 | 21.0 | $131.89 | 11.4 |
| 2,000 | 204.49 | $247.50 | 43.02 | 21.0 | $175.85 | 11.3 |
| 2,500 | 253.30 | $306.69 | 53.39 | 21.1 | $219.82 | 11.3 |
| 3,000 | 302.12 | $365.87 | 63.75 | 21.1 | $263.78 | 11.3 |
| 3,500 | 350.93 | $425.05 | 74.12 | 21.1 | $307.74 | 11.3 |
| 4,000 | 399.75 | $484.24 | 84.49 | 21.1 | $351.71 | 11.2 |
| 4,500 | 448.56 | $543.42 | 94.86 | 21.1 | $395.67 | 11.2 |
| 5,000 | 497.38 | $602.60 | 105.23 | 21.2 | $439.63 | 11.2 |
| **Average Use** | | | | | | |
| 674 | $75.03 | $90.55 | 15.52 | 20.7 | $59.26 | 11.6 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service - Non-Demand Billed***

| Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|
| 0 | $19.13 | $22.73 | $3.60 | 18.8 | $0.00 | 18.8 |
| 100 | $29.63 | $34.71 | 5.08 | 17.1 | $9.03 | 13.1 |
| 200 | $40.13 | $46.68 | 6.56 | 16.3 | $18.06 | 11.3 |
| 300 | $50.62 | $58.66 | $8.04 | 15.9 | $27.09 | 10.3 |
| 400 | $61.12 | $70.64 | 9.52 | 15.6 | $36.12 | 9.8 |
| 500 | $71.62 | $82.62 | 10.99 | 15.4 | $45.15 | 9.4 |
| 750 | $97.87 | $112.56 | $14.69 | 15.0 | $67.73 | 8.9 |
| 1,000 | $124.11 | $142.50 | 18.39 | 14.8 | $90.31 | 8.6 |
| 1,250 | $150.36 | $172.45 | 22.09 | 14.7 | $112.89 | 8.4 |
| 1,500 | $176.61 | $202.39 | $25.79 | 14.6 | $135.46 | 8.3 |
| 1,750 | $202.85 | $232.34 | 29.48 | 14.5 | $158.04 | 8.2 |
| 2,000 | $229.10 | $262.28 | 33.18 | 14.5 | $180.62 | 8.1 |
| 2,500 | $281.59 | $322.17 | 40.58 | 14.4 | $225.77 | 8.0 |
| 3,000 | $334.08 | $382.06 | 47.97 | 14.4 | $270.93 | 7.9 |
| 3,500 | $386.58 | $441.94 | 55.37 | 14.3 | $316.08 | 7.9 |
| 4,000 | $439.07 | $501.83 | 62.76 | 14.3 | $361.23 | 7.8 |
| 4,500 | $491.56 | $561.72 | 70.16 | 14.3 | $406.39 | 7.8 |
| 5,000 | $544.06 | $621.61 | 77.55 | 14.3 | $451.54 | 7.8 |

**Percent Increase Seperatly Metered Space Heating**

| | |
|---|---|
| All Usage | 19.6 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service Secondary***

| Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|---|
| 7 | 0 | $36.25 | $43.79 | $7.53 | 20.8 | $0.00 | 20.8 |
| 7 | 511 | $81.04 | $94.89 | $13.84 | 17.1 | $46.15 | 10.9 |
| 7 | 1,022 | $120.98 | $140.45 | 19.47 | 16.1 | $92.30 | 9.1 |
| 7 | 1,533 | $157.89 | $182.56 | 24.67 | 15.6 | $138.44 | 8.3 |
| 7 | 2,044 | $194.28 | $224.08 | 29.79 | 15.3 | $184.59 | 7.9 |
| 7 | 2,555 | $230.68 | $265.60 | 34.92 | 15.1 | $230.74 | 7.6 |
| 7 | 3,066 | $267.07 | $307.12 | 40.05 | 15.0 | $276.89 | 7.4 |
| 7 | 3,577 | $303.47 | $348.64 | 45.18 | 14.9 | $323.03 | 7.2 |
| 7 | 4,088 | $339.86 | $390.16 | 50.30 | 14.8 | $369.18 | 7.1 |
| 7 | 4,599 | $376.26 | $431.69 | 55.43 | 14.7 | $415.33 | 7.0 |
| 7 | 5,110 | $412.65 | $473.21 | 60.56 | 14.7 | $461.48 | 6.9 |
| 10 | 0 | $51.88 | $63.00 | $11.12 | 21.4 | $0.00 | 21.4 |
| 10 | 730 | $115.87 | $136.00 | $20.14 | 17.4 | $65.93 | 11.1 |
| 10 | 1,460 | $172.92 | $201.09 | 28.17 | 16.3 | $131.85 | 9.2 |
| 10 | 2,190 | $225.64 | $261.25 | 35.60 | 15.8 | $197.78 | 8.4 |
| 10 | 2,920 | $277.64 | $320.56 | 42.93 | 15.5 | $263.70 | 7.9 |
| 10 | 3,650 | $329.63 | $379.88 | 50.25 | 15.2 | $329.63 | 7.6 |
| 10 | 4,380 | $381.62 | $439.20 | 57.57 | 15.1 | $395.55 | 7.4 |
| 10 | 5,110 | $433.61 | $498.51 | 64.90 | 15.0 | $461.48 | 7.3 |
| 10 | 5,840 | $485.61 | $557.83 | 72.22 | 14.9 | $527.40 | 7.1 |
| 10 | 6,570 | $537.60 | $617.15 | 79.55 | 14.8 | $593.33 | 7.0 |
| 10 | 7,300 | $589.59 | $676.46 | 86.87 | 14.7 | $659.25 | 7.0 |
| 25 | 0 | $130.02 | $159.09 | $29.07 | 22.4 | $0.00 | 22.4 |
| 25 | 1,825 | $289.98 | $341.59 | $51.61 | 17.8 | $164.81 | 11.3 |
| 25 | 3,650 | $432.61 | $504.31 | 71.70 | 16.6 | $329.63 | 9.4 |
| 25 | 5,475 | $564.43 | $654.70 | 90.27 | 16.0 | $494.44 | 8.5 |
| 25 | 7,300 | $694.41 | $802.99 | 108.58 | 15.6 | $659.25 | 8.0 |
| 25 | 9,125 | $824.39 | $951.28 | 126.89 | 15.4 | $824.07 | 7.7 |
| 25 | 10,950 | $954.37 | $1,099.57 | 145.20 | 15.2 | $988.88 | 7.5 |
| 25 | 12,775 | $1,084.35 | $1,247.86 | 163.51 | 15.1 | $1,153.69 | 7.3 |
| 25 | 14,600 | $1,214.34 | $1,396.16 | 181.82 | 15.0 | $1,318.51 | 7.2 |
| 25 | 16,425 | $1,344.32 | $1,544.45 | 200.13 | 14.9 | $1,483.32 | 7.1 |
| 25 | 18,250 | $1,474.30 | $1,692.74 | 218.44 | 14.8 | $1,648.13 | 7.0 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service Secondary***

| Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|---|
| 50 | 0 | $260.24 | $319.23 | $58.99 | 22.7 | $0.00 | 22.7 |
| 50 | 3,650 | $580.17 | $684.23 | $104.06 | 17.9 | $329.63 | 11.4 |
| 50 | 7,300 | $865.43 | $1,009.68 | 144.25 | 16.7 | $659.25 | 9.5 |
| 50 | 10,950 | $1,129.06 | $1,310.45 | 181.39 | 16.1 | $988.88 | 8.6 |
| 50 | 14,600 | $1,389.03 | $1,607.03 | 218.01 | 15.7 | $1,318.51 | 8.1 |
| 50 | 18,250 | $1,648.99 | $1,903.62 | 254.63 | 15.4 | $1,648.13 | 7.7 |
| 50 | 21,900 | $1,908.95 | $2,200.20 | 291.25 | 15.3 | $1,977.76 | 7.5 |
| 50 | 25,550 | $2,168.92 | $2,496.78 | 327.87 | 15.1 | $2,307.39 | 7.3 |
| 50 | 29,200 | $2,428.88 | $2,793.37 | 364.49 | 15.0 | $2,637.01 | 7.2 |
| 50 | 32,850 | $2,688.84 | $3,089.95 | 401.11 | 14.9 | $2,966.64 | 7.1 |
| 50 | 36,500 | $2,948.81 | $3,386.53 | 437.73 | 14.8 | $3,296.27 | 7.0 |
| | | | | | | | |
| 100 | 0 | $520.69 | $639.52 | $118.83 | 22.8 | $0.00 | 22.8 |
| 100 | 7,300 | $1,160.55 | $1,369.51 | $208.96 | 18.0 | $659.25 | 11.5 |
| 100 | 14,600 | $1,731.08 | $2,020.41 | 289.34 | 16.7 | $1,318.51 | 9.5 |
| 100 | 21,900 | $2,258.34 | $2,621.95 | 363.61 | 16.1 | $1,977.76 | 8.6 |
| 100 | 29,200 | $2,778.26 | $3,215.12 | 436.86 | 15.7 | $2,637.01 | 8.1 |
| 100 | 36,500 | $3,298.19 | $3,808.29 | 510.10 | 15.5 | $3,296.27 | 7.7 |
| 100 | 43,800 | $3,818.12 | $4,401.45 | 583.34 | 15.3 | $3,955.52 | 7.5 |
| 100 | 51,100 | $4,338.05 | $4,994.62 | 656.58 | 15.1 | $4,614.78 | 7.3 |
| 100 | 58,400 | $4,857.97 | $5,587.79 | 729.82 | 15.0 | $5,274.03 | 7.2 |
| 100 | 65,700 | $5,377.90 | $6,180.96 | 803.06 | 14.9 | $5,933.28 | 7.1 |
| 100 | 73,000 | $5,897.83 | $6,774.12 | 876.30 | 14.9 | $6,592.54 | 7.0 |
| | | | | | | | |
| 150 | 0 | $781.14 | $959.81 | $178.66 | 22.9 | $0.00 | 22.9 |
| 150 | 10,950 | $1,740.93 | $2,054.79 | $313.87 | 18.0 | $988.88 | 11.5 |
| 150 | 21,900 | $2,596.72 | $3,031.15 | 434.43 | 16.7 | $1,977.76 | 9.5 |
| 150 | 32,850 | $3,387.61 | $3,933.45 | 545.84 | 16.1 | $2,966.64 | 8.6 |
| 150 | 43,800 | $4,167.50 | $4,823.20 | 655.70 | 15.7 | $3,955.52 | 8.1 |
| 150 | 54,750 | $4,947.39 | $5,712.96 | 765.57 | 15.5 | $4,944.40 | 7.7 |
| 150 | 65,700 | $5,727.28 | $6,602.71 | 875.43 | 15.3 | $5,933.28 | 7.5 |
| 150 | 76,650 | $6,507.17 | $7,492.46 | 985.29 | 15.1 | $6,922.16 | 7.3 |
| 150 | 87,600 | $7,287.06 | $8,382.21 | 1,095.15 | 15.0 | $7,911.04 | 7.2 |
| 150 | 98,550 | $8,066.96 | $9,271.96 | 1,205.01 | 14.9 | $8,899.93 | 7.1 |
| 150 | 109,500 | $8,846.85 | $10,161.71 | 1,314.87 | 14.9 | $9,888.81 | 7.0 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service Secondary***

| Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|---|
| 200 | 0 | $1,041.60 | $1,280.09 | $238.50 | 22.9 | $0.00 | 22.9 |
| 200 | 14,600 | $2,321.30 | $2,740.08 | $418.77 | 18.0 | $1,318.51 | 11.5 |
| 200 | 29,200 | $3,462.36 | $4,041.88 | 579.52 | 16.7 | $2,637.01 | 9.5 |
| 200 | 43,800 | $4,516.88 | $5,244.95 | 728.07 | 16.1 | $3,955.52 | 8.6 |
| 200 | 58,400 | $5,556.74 | $6,431.29 | 874.55 | 15.7 | $5,274.03 | 8.1 |
| 200 | 73,000 | $6,596.59 | $7,617.63 | 1,021.03 | 15.5 | $6,592.54 | 7.7 |
| 200 | 87,600 | $7,636.45 | $8,803.96 | 1,167.52 | 15.3 | $7,911.04 | 7.5 |
| 200 | 102,200 | $8,676.30 | $9,990.30 | 1,314.00 | 15.1 | $9,229.55 | 7.3 |
| 200 | 116,800 | $9,716.16 | $11,176.63 | 1,460.48 | 15.0 | $10,548.06 | 7.2 |
| 200 | 131,400 | $10,756.01 | $12,362.97 | 1,606.96 | 14.9 | $11,866.57 | 7.1 |
| 200 | 146,000 | $11,795.87 | $13,549.30 | 1,753.44 | 14.9 | $13,185.07 | 7.0 |
| **Average Use** | | | | | | | |
| 9 | 2,776 | $260.39 | $300.43 | $40.03 | 15.4 | $250.70 | 7.8 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service Primary***

| Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|---|
| 100 | 0 | $1,329.96 | $1,559.28 | $229.31 | 17.2 | $0.00 | 17.2 |
| 100 | 7,300 | $1,459.14 | $1,705.07 | $245.93 | 16.9 | $597.35 | 12.0 |
| 100 | 14,600 | $1,588.31 | $1,850.86 | 262.55 | 16.5 | $1,194.71 | 9.4 |
| 100 | 21,900 | $1,717.49 | $1,996.65 | 279.16 | 16.3 | $1,792.06 | 8.0 |
| 100 | 29,200 | $1,846.66 | $2,142.44 | 295.78 | 16.0 | $2,389.41 | 7.0 |
| 100 | 36,500 | $1,975.84 | $2,288.24 | 312.40 | 15.8 | $2,986.77 | 6.3 |
| 100 | 43,800 | $2,105.01 | $2,434.03 | 329.01 | 15.6 | $3,584.12 | 5.8 |
| 100 | 51,100 | $2,234.19 | $2,579.82 | 345.63 | 15.5 | $4,181.47 | 5.4 |
| 100 | 58,400 | $2,363.36 | $2,725.61 | 362.25 | 15.3 | $4,778.83 | 5.1 |
| 100 | 65,700 | $2,492.54 | $2,871.40 | 378.86 | 15.2 | $5,376.18 | 4.8 |
| 100 | 73,000 | $2,621.71 | $3,017.19 | 395.48 | 15.1 | $5,973.54 | 4.6 |
| 150 | 0 | $1,917.37 | $2,246.42 | $329.05 | 17.2 | $0.00 | 17.2 |
| 150 | 10,950 | $2,111.13 | $2,465.11 | $353.98 | 16.8 | $896.03 | 11.8 |
| 150 | 21,900 | $2,304.89 | $2,683.79 | 378.90 | 16.4 | $1,792.06 | 9.2 |
| 150 | 32,850 | $2,498.65 | $2,902.48 | 403.83 | 16.2 | $2,688.09 | 7.8 |
| 150 | 43,800 | $2,692.41 | $3,121.17 | 428.75 | 15.9 | $3,584.12 | 6.8 |
| 150 | 54,750 | $2,886.18 | $3,339.86 | 453.68 | 15.7 | $4,480.15 | 6.2 |
| 150 | 65,700 | $3,079.94 | $3,558.54 | 478.60 | 15.5 | $5,376.18 | 5.7 |
| 150 | 76,650 | $3,273.70 | $3,777.23 | 503.53 | 15.4 | $6,272.21 | 5.3 |
| 150 | 87,600 | $3,467.46 | $3,995.92 | 528.45 | 15.2 | $7,168.24 | 5.0 |
| 150 | 98,550 | $3,661.23 | $4,214.60 | 553.38 | 15.1 | $8,064.27 | 4.7 |
| 150 | 109,500 | $3,854.99 | $4,433.29 | 578.30 | 15.0 | $8,960.30 | 4.5 |
| 200 | 0 | $2,504.77 | $2,933.56 | $428.79 | 17.1 | $0.00 | 17.1 |
| 200 | 14,600 | $2,763.12 | $3,225.14 | $462.02 | 16.7 | $1,194.71 | 11.7 |
| 200 | 29,200 | $3,021.47 | $3,516.72 | 495.26 | 16.4 | $2,389.41 | 9.2 |
| 200 | 43,800 | $3,279.82 | $3,808.31 | 528.49 | 16.1 | $3,584.12 | 7.7 |
| 200 | 58,400 | $3,538.17 | $4,099.89 | 561.73 | 15.9 | $4,778.83 | 6.8 |
| 200 | 73,000 | $3,796.52 | $4,391.47 | 594.96 | 15.7 | $5,973.54 | 6.1 |
| 200 | 87,600 | $4,054.86 | $4,683.06 | 628.19 | 15.5 | $7,168.24 | 5.6 |
| 200 | 102,200 | $4,313.21 | $4,974.64 | 661.43 | 15.3 | $8,362.95 | 5.2 |
| 200 | 116,800 | $4,571.56 | $5,266.22 | 694.66 | 15.2 | $9,557.66 | 4.9 |
| 200 | 131,400 | $4,829.91 | $5,557.81 | 727.89 | 15.1 | $10,752.36 | 4.7 |
| 200 | 146,000 | $5,088.26 | $5,849.39 | 761.13 | 15.0 | $11,947.07 | 4.5 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service Primary***

| Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|---|
| 500 | 0 | $6,029.17 | $7,056.40 | $1,027.22 | 17.0 | $0.00 | 17.0 |
| 500 | 36,500 | $6,675.05 | $7,785.35 | $1,110.31 | 16.6 | $2,986.77 | 11.5 |
| 500 | 73,000 | $7,320.92 | $8,514.31 | 1,193.39 | 16.3 | $5,973.54 | 9.0 |
| 500 | 109,500 | $7,966.80 | $9,243.27 | 1,276.47 | 16.0 | $8,960.30 | 7.5 |
| 500 | 146,000 | $8,612.67 | $9,972.23 | 1,359.56 | 15.8 | $11,947.07 | 6.6 |
| 500 | 182,500 | $9,258.54 | $10,701.19 | 1,442.64 | 15.6 | $14,933.84 | 6.0 |
| 500 | 219,000 | $9,904.42 | $11,430.14 | 1,525.73 | 15.4 | $17,920.61 | 5.5 |
| 500 | 255,500 | $10,550.29 | $12,159.10 | 1,608.81 | 15.2 | $20,907.37 | 5.1 |
| 500 | 292,000 | $11,196.17 | $12,888.06 | 1,691.89 | 15.1 | $23,894.14 | 4.8 |
| 500 | 328,500 | $11,842.04 | $13,617.02 | 1,774.98 | 15.0 | $26,880.91 | 4.6 |
| 500 | 365,000 | $12,487.92 | $14,345.98 | 1,858.06 | 14.9 | $29,867.68 | 4.4 |
| 750 | 0 | $8,966.18 | $10,492.09 | $1,525.92 | 17.0 | $0.00 | 17.0 |
| 750 | 54,750 | $9,934.99 | $11,585.53 | $1,650.54 | 16.6 | $4,480.15 | 11.5 |
| 750 | 109,500 | $10,903.80 | $12,678.97 | 1,775.17 | 16.3 | $8,960.30 | 8.9 |
| 750 | 164,250 | $11,872.61 | $13,772.41 | 1,899.79 | 16.0 | $13,440.45 | 7.5 |
| 750 | 219,000 | $12,841.42 | $14,865.84 | 2,024.42 | 15.8 | $17,920.61 | 6.6 |
| 750 | 273,750 | $13,810.24 | $15,959.28 | 2,149.04 | 15.6 | $22,400.76 | 5.9 |
| 750 | 328,500 | $14,779.05 | $17,052.72 | 2,273.67 | 15.4 | $26,880.91 | 5.5 |
| 750 | 383,250 | $15,747.86 | $18,146.15 | 2,398.30 | 15.2 | $31,361.06 | 5.1 |
| 750 | 438,000 | $16,716.67 | $19,239.59 | 2,522.92 | 15.1 | $35,841.21 | 4.8 |
| 750 | 492,750 | $17,685.48 | $20,333.03 | 2,647.55 | 15.0 | $40,321.36 | 4.6 |
| 750 | 547,500 | $18,654.29 | $21,426.46 | 2,772.17 | 14.9 | $44,801.51 | 4.4 |
| 1,000 | 0 | $11,903.18 | $13,927.79 | $2,024.61 | 17.0 | $0.00 | 17.0 |
| 1,000 | 73,000 | $13,194.93 | $15,385.71 | $2,190.78 | 16.6 | $5,973.54 | 11.4 |
| 1,000 | 146,000 | $14,486.68 | $16,843.63 | 2,356.94 | 16.3 | $11,947.07 | 8.9 |
| 1,000 | 219,000 | $15,778.43 | $18,301.54 | 2,523.11 | 16.0 | $17,920.61 | 7.5 |
| 1,000 | 292,000 | $17,070.18 | $19,759.46 | 2,689.28 | 15.8 | $23,894.14 | 6.6 |
| 1,000 | 365,000 | $18,361.93 | $21,217.37 | 2,855.45 | 15.6 | $29,867.68 | 5.9 |
| 1,000 | 438,000 | $19,653.67 | $22,675.29 | 3,021.61 | 15.4 | $35,841.21 | 5.4 |
| 1,000 | 511,000 | $20,945.42 | $24,133.20 | 3,187.78 | 15.2 | $41,814.75 | 5.1 |
| 1,000 | 584,000 | $22,237.17 | $25,591.12 | 3,353.95 | 15.1 | $47,788.28 | 4.8 |
| 1,000 | 657,000 | $23,528.92 | $27,049.04 | 3,520.12 | 15.0 | $53,761.82 | 4.6 |
| 1,000 | 730,000 | $24,820.67 | $28,506.95 | 3,686.28 | 14.9 | $59,735.35 | 4.4 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC2 General Service Primary***

| Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Base Rate Change Amount | Base Rate Change Percent | Supply Costs | Total Bill Percent Change |
|---|---|---|---|---|---|---|---|
| 1,500 | 0 | $17,777.20 | $20,799.19 | $3,021.99 | 17.0 | $0.00 | 17.0 |
| 1,500 | 109,500 | $19,714.82 | $22,986.06 | $3,271.25 | 16.6 | $8,960.30 | 11.4 |
| 1,500 | 219,000 | $21,652.44 | $25,172.94 | 3,520.50 | 16.3 | $17,920.61 | 8.9 |
| 1,500 | 328,500 | $23,590.06 | $27,359.81 | 3,769.75 | 16.0 | $26,880.91 | 7.5 |
| 1,500 | 438,000 | $25,527.69 | $29,546.69 | 4,019.00 | 15.7 | $35,841.21 | 6.5 |
| 1,500 | 547,500 | $27,465.31 | $31,733.56 | 4,268.25 | 15.5 | $44,801.51 | 5.9 |
| 1,500 | 657,000 | $29,402.93 | $33,920.43 | 4,517.50 | 15.4 | $53,761.82 | 5.4 |
| 1,500 | 766,500 | $31,340.55 | $36,107.31 | 4,766.75 | 15.2 | $62,722.12 | 5.1 |
| 1,500 | 876,000 | $33,278.18 | $38,294.18 | 5,016.01 | 15.1 | $71,682.42 | 4.8 |
| 1,500 | 985,500 | $35,215.80 | $40,481.06 | 5,265.26 | 15.0 | $80,642.72 | 4.5 |
| 1,500 | 1,095,000 | $37,153.42 | $42,667.93 | 5,514.51 | 14.8 | $89,603.03 | 4.4 |
| | | | | | | | |
| 2,000 | 0 | $23,651.21 | $27,670.59 | $4,019.38 | 17.0 | $0.00 | 17.0 |
| 2,000 | 146,000 | $26,234.70 | $30,586.42 | $4,351.72 | 16.6 | $11,947.07 | 11.4 |
| 2,000 | 292,000 | $28,818.20 | $33,502.25 | 4,684.05 | 16.3 | $23,894.14 | 8.9 |
| 2,000 | 438,000 | $31,401.70 | $36,418.08 | 5,016.39 | 16.0 | $35,841.21 | 7.5 |
| 2,000 | 584,000 | $33,985.19 | $39,333.91 | 5,348.72 | 15.7 | $47,788.28 | 6.5 |
| 2,000 | 730,000 | $36,568.69 | $42,249.75 | 5,681.06 | 15.5 | $59,735.35 | 5.9 |
| 2,000 | 876,000 | $39,152.19 | $45,165.58 | 6,013.39 | 15.4 | $71,682.42 | 5.4 |
| 2,000 | 1,022,000 | $41,735.68 | $48,081.41 | 6,345.73 | 15.2 | $83,629.49 | 5.1 |
| 2,000 | 1,168,000 | $44,319.18 | $50,997.24 | 6,678.06 | 15.1 | $95,576.56 | 4.8 |
| 2,000 | 1,314,000 | $46,902.68 | $53,913.07 | 7,010.40 | 14.9 | $107,523.63 | 4.5 |
| 2,000 | 1,460,000 | $49,486.17 | $56,828.91 | 7,342.73 | 14.8 | $119,470.70 | 4.3 |
| | | | | | | | |
| **Average Use** | | | | | | | |
| 256 | 105,514 | $5,029.75 | $5,810.42 | 780.68 | 15.5 | $8,634.13 | 5.7 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC3 Municipal Street Lighting***

| Lumens | Luminaire Type | Present Rate | Proposed Rate | Base Rate Change Amount | Base Rate Change Percent |
|---|---|---|---|---|---|
| Street Lighting Luminaries: | | | | | |
| 5,800 | Sodium Vapor | $24.73 | $32.65 | $7.92 | 32.0 |
| 9,500 | Sodium Vapor | $27.09 | $35.77 | $8.68 | 32.0 |
| 16,000 | Sodium Vapor | $30.76 | $40.61 | $9.85 | 32.0 |
| 27,500 | Sodium Vapor | $39.49 | $52.14 | $12.65 | 32.0 |
| 46,000 | Sodium Vapor | $51.95 | $68.59 | $16.64 | 32.0 |
| 3,900 | LED | $28.65 | $37.83 | $9.18 | 32.0 |
| 5,000 | LED | $28.74 | $37.95 | $9.21 | 32.0 |
| 5,890 | LED | $29.16 | $38.50 | $9.34 | 32.0 |
| 9,365 | LED | $35.79 | $47.26 | $11.47 | 32.0 |
| 16,000 | LED | $30.52 | $40.30 | $9.78 | 32.0 |
| 22,000 | LED | $31.11 | $41.08 | $9.97 | 32.0 |
| Flood Lighting Luminaries: | | | | | |
| 14,500 | LED | $28.91 | $38.17 | $9.26 | 32.0 |
| 28,700 | LED | $31.36 | $41.41 | $10.05 | 32.0 |
| The following luminaires will no longer be installed. Charges are for existing installations only: | | | | | |
| 46,000 | Sodium Vapor | $43.60 | $57.57 | $13.97 | 32.0 |
| 27,500 | Sodium Vapor | $39.46 | $52.10 | $12.64 | 32.0 |
| 4,000 | Mercury Vapor | $17.54 | $23.16 | $5.62 | 32.0 |
| 7,900 | Mercury Vapor | $21.25 | $28.06 | $6.81 | 32.0 |
| 12,000 | Mercury Vapor | $27.68 | $36.55 | $8.87 | 32.0 |
| MUNI OVERHEAD - 15 FOOT POLE | | $0.60 | $0.79 | $0.19 | 32.0 |
| Underground Service Company Owns & Maintains | | $274.68 | $362.68 | $88.00 | 32.0 |
| Underground Service Customer Owns & Maintains | | $66.48 | $87.78 | $21.30 | 32.0 |

# PIKE COUNTY LIGHT & POWER COMPANY

Monthly Billing Comparison
Reflecting Proposed Rate Changes

***SC4 Private Area Lighting***

| Present SC4 (Private Area Lighting - Monthly) | | | Proposed | Base Rate Change | |
|---|---|---|---|---|---|
| Lumens | Luminaire Type | Charge | Rate | Amount | Percent |
| Private Lighting Luminaries | | | | | |
| 5,800 | Sodium Vapor | $24.73 | $32.65 | $7.92 | 32.0 |
| 16,000 | Sodium Vapor | $30.76 | $40.61 | $9.85 | 32.0 |
| 3,900 | LED | $32.47 | $42.87 | $10.40 | 32.0 |
| 5,000 | LED | $32.56 | $42.99 | $10.43 | 32.0 |
| 7,250 | LED | $32.97 | $43.53 | $10.56 | 32.0 |
| 9,365 | LED | $33.66 | $44.44 | $10.78 | 32.0 |
| Flood Light Luminaries | | | | | |
| 14,500 | LED | $35.31 | $46.62 | $11.31 | 32.0 |
| 28,700 | LED | $37.76 | $49.86 | $12.10 | 32.0 |
| The following luminaires will no longer be installed. Charges are for existing installations only: | | | | | |
| 4,000 | Mercury Vapor | $13.66 | $18.04 | $4.38 | 32.0 |
| 4,000 | Mercury Vapor | $12.26 | $16.19 | $3.93 | 32.0 |
| 7,900 | Mercury Vapor | $16.55 | $21.85 | $5.30 | 32.0 |
| 7,900 | Mercury Vapor | $15.10 | $19.94 | $4.84 | 32.0 |
| 12,000 | Mercury Vapor | $21.56 | $28.47 | $6.91 | 32.0 |
| 22,500 | Mercury Vapor | $28.02 | $37.00 | $8.98 | 32.0 |
| 27,500 | Sodium Vapor | $39.46 | $52.10 | $12.64 | 32.0 |

**PIKE COUNTY LIGHT AND POWER COMPANY**

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

| Customer Classification | Base Rate Revenue ($) | Supply Costs & Other Charges Revenue ($) | Total Revenue ($) |
|---|---|---|---|
| SC 1 - Residential | $3,761,388 | $3,314,806 | $7,076,193 |
| Secondary - Customer Charges | $201,852 | 21,861 | $223,714 |
| SC No. 2 - Secondary - Demand | 2,839,444 | 3,445,912 | 6,285,357 |
| SC No. 2 - Secondary - Non Demand | 121,241 | 143,302 | 264,544 |
| SC No. 2 Primary | 562,960 | 1,066,633 | 1,629,593 |
| SC 3 - Municipal Street Lighting | 117,133 | 44,332 | 161,465 |
| SC 4 - Private Area Lighting | 51,509 | 21,388 | 72,897 |
| Total | $7,655,528 | $8,058,234 | $15,713,762 |

Note: Pike has other operating revenues of $125,100

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

| | |
|---|---|
| SC 1 - Residential | 4,476 |
| SC No. 2 - Secondary - Demand | 963 |
| SC No. 2 - Secondary - Non Demand | 11 |
| SC No. 2 Primary | 9 |
| SC 3 - Municipal Street Lighting | 12 |
| SC 4 - Private Area Lighting | 78 |
| Total | 5,550 |

**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 electric customers whose bills will be increased and the annual increase in dollars.

| Customer Classification | Customers @ September 30, 2025 | Annual Increase ($) |
|---|---|---|
| SC 1 - Residential | 4,476 | $818,384 |
| SC No. 2 - Secondary - Customer Charges | | 42,091 |
| SC No. 2 - Secondary - Demand | 963 | 486,075 |
| SC No. 2 - Secondary - Non Demand | 11 | 18,935 |
| SC No. 2 Primary | 9 | 97,368 |
| SC 3 - Municipal Street Lighting | 12 | 27,389 |
| SC 4 - Private Area Lighting | 78 | 12,044 |
| Total | 5,550 | $1,502,286 |

53.52(b)(5) to (6) -- Statement of the number of gas customers whose bills will be decreased and the annual decrease in dollars.

| Customer Classification | Customers @ September 30, 2025 | Annual Decrease ($) |
|---|---|---|
| SC 1 - Residential | 0 | $0 |
| SC No. 2 - Secondary - Demand | 0 | 0 |
| SC No. 2 - Secondary - Non Demand | 0 | 0 |
| SC No. 2 Primary | 0 | 0 |
| SC 3 - Municipal Street Lighting | 0 | 0 |
| SC 4 - Private Area Lighting | 0 | 0 |
| Total | 0 | $0 |

**PIKE COUNTY LIGHT & POWER COMPANY**

Bill Comparison Rate Year

***Summary of Proposed Increases***

| | Sales | Delivery Charges | SBC | FTA | Delivery STAS | Default Svc | Default Svc Sales Tax | Delivery Sales Tax | Total |
|---|---|---|---|---|---|---|---|---|---|
| Revenue: | | | | | | | | | |
| Service Classification No. 1 | 35,464,237 | $1,014,036 | $0 | ($188,761) | ($6,891) | $0 | $0 | $0 | $818,384 |
| Service Classification No. 2 | | | | | | | | | |
| Secondary - Customer Charges | | $49,586 | $0 | ($10,093) | ($356) | $0 | $0 | $2,954 | $42,091 |
| Secondary - Demand Billed | 34,751,778 | $597,234 | $0 | ($141,972) | ($4,736) | $0 | $0 | $35,550 | $486,075 |
| Secondary - Non-Demand Billed | 1,441,402 | $23,780 | $0 | ($6,062) | ($198) | $0 | $0 | $1,415 | $18,935 |
| Primary | 12,289,759 | $119,352 | $0 | ($28,148) | ($942) | $0 | $0 | $7,105 | $97,368 |
| Service Classification No. 2 | 48,482,938 | 789,951 | 0 | (186,275) | (6,231) | 0 | 0 | 47,023 | 644,469 |
| Service Classification No. 3 | 328,097 | $31,578 | $0 | ($5,857) | ($214) | $0 | $0 | $1,882 | $27,389 |
| Service Classification No. 4 | 152,075 | $13,886 | $0 | ($2,575) | ($94) | $0 | $0 | $828 | $12,044 |
| Total | 84,427,347 | $1,849,451 | $0 | ($383,468) | ($13,430) | $0 | $0 | $49,733 | $1,502,286 |
| Average Price per kWh (cents per kWh): | | | | | | | | | |
| Service Classification No. 1 | | 2.859 | 0.000 | -0.532 | -0.019 | 0.000 | 0.000 | 0.000 | 2.308 |
| Service Classification No. 2 | | | | | | | | | |
| Secondary - Demand Billed | | 1.719 | 0.000 | -0.409 | -0.014 | 0.000 | 0.000 | 0.102 | 1.399 |
| Secondary - Non-Demand Billed | | 1.650 | 0.000 | -0.421 | -0.014 | 0.000 | 0.000 | 0.098 | 1.314 |
| Primary | | 0.971 | 0.000 | -0.229 | -0.008 | 0.000 | 0.000 | 0.058 | 0.792 |
| Service Classification No. 2 | | 1.629 | 0.000 | -0.384 | -0.013 | 0.000 | 0.000 | 0.097 | 1.329 |
| Service Classification No. 3 | | 9.625 | 0.000 | -1.785 | -0.065 | 0.000 | 0.000 | 0.574 | 8.348 |
| Service Classification No. 4 | | 9.131 | 0.000 | -1.694 | -0.062 | 0.000 | 0.000 | 0.544 | 7.920 |
| Total | | 2.191 | 0.000 | -0.454 | -0.016 | 0.000 | 0.000 | 0.059 | 1.779 |
| Percentage Increases | | | | | | | | | |
| Service Classification No. 1 | | 27.0% | 0.0% | -100.0% | 111.8% | 0.0% | 0.0% | 0.0% | 11.6% |
| Service Classification No. 2 | | | | | | | | | |
| Secondary - Demand Billed | | 21.0% | 0.0% | -100.0% | 107.7% | 0.0% | 0.0% | 20.9% | 7.7% |
| Secondary - Non-Demand Billed | | 19.6% | 0.0% | -100.0% | 107.7% | 0.0% | 0.0% | 19.4% | 7.2% |
| Primary | | 21.2% | 0.0% | -100.0% | 114.3% | 0.0% | 0.0% | 21.2% | 6.0% |
| Service Classification No. 2 | | 21.2% | 0.0% | -100.0% | 108.3% | 0.0% | 0.0% | 21.1% | 7.7% |
| Service Classification No. 3 | | 27.0% | 0.0% | -100.0% | 114.0% | 0.0% | 0.0% | 26.8% | 17.0% |
| Service Classification No. 4 | | 27.0% | 0.0% | -100.0% | 114.8% | 0.0% | 0.0% | 26.8% | 16.5% |
| Total | | 24.2% | 0.0% | -100.0% | 106.7% | 0.0% | 0.0% | 21.4% | 9.6% |

**PIKE COUNTY LIGHT & POWER COMPANY**

Rate Year

***Revenue Summary at Current Rates***

| Revenue: | Sales | Delivery Charges | SBC | DISC | Delivery STAS | Default Svc | Default Serv Sales Tax | Delivery Sales Tax | Total |
|---|---|---|---|---|---|---|---|---|---|
| Service Classification No. 1 | 35,464,237 | $3,761,388 | $13,830 | $188,761 | ($6,040) | $3,118,255 | $0 | $0 | $7,076,193 |
| Service Classification No. 2 | | | | | | | | | |
| Secondary - Customer Charges | | 201,852 | | 10,093 | (323) | | | $12,092 | 223,714 |
| Secondary - Demand Billed | 34,751,778 | 2,839,444 | 0 | 141,972 | (4,543) | $2,960,744 | $177,645 | $170,094 | 6,285,357 |
| Secondary - Non-Demand Billed | 1,441,402 | 121,241 | 0 | 6,062 | (194) | $122,803 | $7,368 | $7,263 | 264,544 |
| Primary | 12,289,759 | 562,960 | 0 | 28,148 | (901) | $948,737 | $56,924 | $33,724 | 1,629,593 |
| Service Classification No. 2 | 48,482,938 | 3,725,499 | 0 | 186,275 | (5,961) | 4,032,285 | 241,937 | 223,172 | 8,403,207 |
| Service Classification No. 3 | 328,097 | 117,133 | 0 | 5,857 | (187) | $29,855 | $1,791 | $7,017 | 161,465 |
| Service Classification No. 4 | 152,075 | 51,509 | 0 | 2,575 | (82) | $14,915 | $895 | $3,086 | 72,897 |
| Total | 84,427,347 | $7,655,528 | $13,830 | $383,468 | ($12,271) | $7,195,309 | $244,623 | $233,275 | $15,713,762 |

| Average Price per kWh (cents per kWh): | Delivery Charges | SBC | DISC | Delivery STAS | Default Svc | Default Serv Sales Tax | Delivery Sales Tax | Total |
|---|---|---|---|---|---|---|---|---|
| Service Classification No. 1 | 10.606 | 0.039 | 0.532 | -0.017 | 8.793 | 0.000 | 0.000 | 19.953 |
| Service Classification No. 2 | | | | | | | | |
| Secondary - Demand Billed | 8.171 | 0.000 | 0.409 | -0.013 | 8.520 | 0.511 | 0.489 | 18.086 |
| Secondary - Non-Demand Billed | 8.411 | 0.000 | 0.421 | -0.013 | 8.520 | 0.511 | 0.504 | 18.353 |
| Primary | 4.581 | 0.000 | 0.229 | -0.007 | 7.720 | 0.463 | 0.274 | 13.260 |
| Service Classification No. 2 | 7.684 | 0.000 | 0.384 | -0.012 | 8.317 | 0.499 | 0.460 | 17.332 |
| Service Classification No. 3 | 35.701 | 0.000 | 1.785 | -0.057 | 9.099 | 0.546 | 2.139 | 49.212 |
| Service Classification No. 4 | 33.871 | 0.000 | 1.694 | -0.054 | 9.808 | 0.588 | 2.029 | 47.935 |
| Total | 9.068 | 0.016 | 0.454 | -0.015 | 8.522 | 0.290 | 0.276 | 18.612 |

**PIKE COUNTY LIGHT & POWER COMPANY**

Rate Year

***Revenue Summary at Proposed Rates***

| Revenue: | Sales | Delivery Charges | SBC | DISC | Delivery STAS | Default Svc | Default Serv Sales Tax | Delivery Sales Tax | Total |
|---|---|---|---|---|---|---|---|---|---|
| Service Classification No. 1 | 35,464,237 | $4,775,423 | $13,830 | $0 | ($12,931) | $3,118,255 | $0 | $0 | $7,894,577 |
| Service Classification No. 2 | | | | | | | | | |
| Secondary - Customer Charges | | 251,438 | | 0 | (679) | | | $15,046 | $265,805 |
| Secondary - Demand Billed | 34,751,778 | 3,436,678 | 0 | 0 | (9,279) | $2,960,744 | $177,645 | $205,644 | 6,771,432 |
| Secondary - Non-Demand Billed | 1,441,402 | 145,021 | 0 | 0 | (392) | $122,803 | $7,368 | $8,678 | 283,478 |
| Primary | 12,289,759 | 682,313 | 0 | 0 | (1,842) | $948,737 | $56,924 | $40,828 | 1,726,961 |
| Service Classification No. 2 | 48,482,938 | 4,515,450 | 0 | 0 | (11,513) | 4,032,285 | 241,937 | 255,150 | 9,047,676 |
| Service Classification No. 3 | 328,097 | 148,711 | 0 | 0 | (402) | $29,855 | $1,791 | $8,899 | 188,854 |
| Service Classification No. 4 | 152,075 | 65,395 | 0 | 0 | (177) | $14,915 | $895 | $3,913 | 84,941 |
| Total | 84,427,347 | $9,504,979 | $13,830 | $0 | ($25,022) | $7,195,309 | $244,623 | $267,962 | $17,216,048 |

Average Price per kWh (cents per kWh):

| | Delivery Charges | SBC | DISC | Delivery STAS | Default Svc | Default Serv Sales Tax | Delivery Sales Tax | Total |
|---|---|---|---|---|---|---|---|---|
| Service Classification No. 1 | 13.465 | 0.039 | 0.000 | -0.036 | 8.793 | 0.000 | 0.000 | 22.261 |
| Service Classification No. 2 | | | | | | | | |
| Secondary - Demand Billed | 9.889 | 0.000 | 0.000 | -0.027 | 8.520 | 0.511 | 0.592 | 19.485 |
| Secondary - Non-Demand Billed | 10.061 | 0.000 | 0.000 | -0.027 | 8.520 | 0.511 | 0.602 | 19.667 |
| Primary | 5.552 | 0.000 | 0.000 | -0.015 | 7.720 | 0.463 | 0.332 | 14.052 |
| Service Classification No. 2 | 9.313 | 0.000 | 0.000 | -0.024 | 8.317 | 0.499 | 0.526 | 18.662 |
| Service Classification No. 3 | 45.325 | 0.000 | 0.000 | -0.122 | 9.099 | 0.546 | 2.712 | 57.560 |
| Service Classification No. 4 | 43.002 | 0.000 | 0.000 | -0.116 | 9.808 | 0.588 | 2.573 | 55.855 |
| Total | 11.258 | 0.016 | 0.000 | -0.030 | 8.522 | 0.290 | 0.317 | 20.392 |

**PIKE COUNTY LIGHT & POWER COMPANY**

Monthly Billing Comparison*
Reflecting Proposed Delivery Rate Changes
Includes Supply Costs

| SC | Demand (kW) | Monthly Usage (kWh) | Bill at Present Rates | Bill at Proposed Rates | Change Amount | Percent |
|---|---|---|---|---|---|---|
| 1 | n/a | 674 | 134.29 | 149.81 | 15.52 | 11.6 |
| 2 | 9.0 | 2,776 | 511.09 | 551.12 | 40.03 | 7.8 |

* Basis for bill impacts used in the "Notice of Proposed Changes".

**PIKE COUNTY LIGHT AND POWER COMPANY**

Impact of Proposed Rate Change on Total Billed Revenue
For the 12 Months Ending September 2025

| | | | | Total Revenue at: | | Increase: | |
|---|---|---|---|---|---|---|---|
| Service Class | Type of Service | Annual Bills | Total Sales (kWh) | Present Rates | Proposed Rates | Rev Change | Percent Change |
| 1 | Residential Service | 53,714 | 35,464,237 | 7,076,193 | 7,894,577 | 818,384 | 11.6% |
| 2 | General Sec - Customer Charge | | | 223,714 | 265,805 | 42,091 | 18.8% |
| 3 | General Secondary - Demand | 11,558 | 34,751,778 | 6,285,357 | 6,771,432 | 486,075 | 7.7% |
| 4 | General Secondary - Non-Demand | 137 | 1,441,402 | 264,544 | 283,478 | 18,935 | 7.2% |
| 5 | General Primary Service | 108 | 12,289,759 | 1,629,593 | 1,726,961 | 97,368 | 6.0% |
| 6 | Municipal Street Lighting | 144 | 328,097 | 161,465 | 188,854 | 27,389 | 17.0% |
| 7 | Private Area Lighting | 935 | 152,075 | 72,897 | 84,941 | 12,044 | 16.5% |
| Total | | 66,596 | 84,427,347 | 15,713,762 | 17,216,048 | 1,502,286 | 9.6% |

* For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues.

**PIKE COUNTY LIGHT AND POWER COMPANY**

Impact of Proposed Rate Change on Delivery Billed Revenue
For the 12 Months Ending September 2025

| | | | | Delivery Revenue at: | | Increase: | |
|---|---|---|---|---|---|---|---|
| Service Class | Type of Service | Annual Bills | Total Sales (kWh) | Present Rates | Proposed Rates | Rev Change | Percent Change |
| 1 | Residential Service | 53,714 | 35,464,237 | 3,761,388 | 4,775,423 | 1,014,036 | 27.0% |
| 2 | | | | 201,852 | 251,438 | 49,586 | 24.6% |
| 3 | General Secondary - Demand | 11,558 | 34,751,778 | 2,839,444 | 3,436,678 | 597,234 | 21.0% |
| 4 | General Secondary - Non-Demand | 137 | 1,441,402 | 121,241 | 145,021 | 23,780 | 19.6% |
| 5 | General Primary Service | 108 | 12,289,759 | 562,960 | 682,313 | 119,352 | 21.2% |
| 6 | Municipal Street Lighting | 144 | 328,097 | 117,133 | 148,711 | 31,578 | 27.0% |
| 7 | Private Area Lighting | 935 | 152,075 | 51,509 | 65,395 | 13,886 | 27.0% |
| Total | | 66,596 | 84,427,347 | 7,655,528 | 9,504,979 | 1,849,451 | 24.2% |

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

| | | |
|---|---|---|
| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | DOCKET NO. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company (electric) | : | |

**Pike County Light and Power Company (Electric)**
**Statement No. 2**
**Direct Testimony of**
**Accounting Panel**

**Charles Lenns and Matthew Lenns**

**Q. Would the members of the Accounting Panel 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, NY 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 the 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 the Accounting Panel's testimony in this proceeding?**

A. We will address the following topics:

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

**Q. Are you sponsoring any exhibits in this filing?**

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

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

- Historic and forecast electric sales and revenues (Exhibit E-5).

## COSTS DRIVING RATE INCREASE

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

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

**Q. Please explain why Pike is seeking an electric 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, ensure continued safety, and modernize its electrical system in order to better serve its customers. Additionally, interest rates on debt incurred in order to make capital investments has doubled since Pike's last electric rate filing. Supply chain issues and inflation for materials and supplies, especially for transformer purchases, has also contributed to the increase in Pike's operating and capital costs. Assuming new rates go into effect in the fourth quarter of 2025, it will be over four 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 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 $1,874,600.

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

A. The increase of $1,874,600 can be attributed to the following:

- Change in Rate Base - $1,775,255

| | | |
|---|---|---|
| • Change in Return | - | 461,248 |
| • Revenue Growth | - | (1,379,319) |
| • O&M Expenses | - | 503,600 |
| • Depreciation & Amortization Expense | - | 457,700 |
| • Income Taxes and Other | - | 56,116 |
| Total Net Increase | | $1,874,600 |

**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 electric commodity purchase price with electric suppliers?**

A. No, Pike operates under an electric supply and transportation agreement with Orange & Rockland Utilities, Inc. ("O&R"). The Company purchases all of its electricity from O&R on a "full services contract" basis, meaning that O&R is required to sell to Pike all of the electricity that Pike needs to serve its customers.

**Q. Is Pike able to purchase electricity from other suppliers?**

A. Currently, Pike cannot purchase electricity from other suppliers because Pike is unable to transport electricity over the O&R system. No other electricity is available to Pike. However, Pike and O&R are currently negotiating an amendment to Pike's electric supply and transportation agreement with O&R that would allow Pike to purchase electricity from electric marketing companies to be delivered on O&R's system to Pike's electric distribution wires in the middle of the Matamoras bridge in Port Jervis, New York.

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

A. Yes, Pike expects to negotiate a contract with O&R that would allow Pike to purchase electricity either from O&R or from electric marketers. As noted above, O&R will continue to transport electric to Pike's distribution system in Port Jervis, New York. The ability to competitively bid Pike's electric commodity cost should reduce its electric commodity price. The savings resulting from Pike's renegotiated contract will be passed on to Pike's electric customers. Pike will seek Commission approval for the amended contract and any potential changes to how Pike purchases energy in its next default service proceeding.

**Q. Can you describe other changes and improvements that Pike is exploring relative to its electric purchasing plan and its electric distribution system?**

A. Yes. As part of the Commission-approved Settlement at Docket Nos. A-2021-3025659 *et al.* regarding Pike's acquisition by a company controlled by Argo Infrastructures, LP, Pike is required to undertake a study to determine the feasibility of connecting to the PJM grid so that it could purchase its electric power in Pennsylvania. The Company is currently conducting this study and considering its several inter-connect options in Pennsylvania. The Company expects to file its study results with the PAPUC in July of 2025.

**Q. Can you explain the changes the Company is requesting with respect to circumstances where customers are disconnected from electric power, and then later reconnected to electric power?**

A. Yes. Pike disconnects, and then reconnects, electric power most commonly in three circumstances. The first circumstance is where customer power is shut off for failure by customers to pay their electric bill. If a customer either pays their bill in full, or, in the alternative, makes a down payment on their bill and enters into a payment plan with the Company, the Company will reconnect the customer's electric power and charge a reconnect fee of $37 for each reconnect. The Company plans no changes with respect to these customers. The second circumstance is the relatively rare circumstance where the customer requests a power disconnect because the customer will be away from home for an extended period of time. The third circumstance is where a landlord of rental property requests a disconnect for rental units that are vacant because that rental unit may be in between tenants. In both the second and third circumstances, the customer will request a reconnect when they return from an extended stay away from their residence or place of business (circumstance 2), or will request an electric reconnect when the rental unit is occupied (circumstance 3). In both cases, the disconnect and reconnect services are currently provided to Pike customers free of charge. However, the Company incurs significant costs in disconnecting and then reconnecting customers who purchase electric power from Pike. These costs include electric technicians labor costs, materials and supplies, auto expenses, and often, employee overtime costs. In order to discourage these ever-increasing customer requests, and in order to control related operating costs, the Company proposes to charge customers a $50 fee to disconnect from electric service, and a $50 fee to re-connect to electric service. This fee would discourage company customers from frequent disconnect and reconnect requests, and consequently would reduce costs for all of Pike's customers.

## EXHIBIT E-1 HISTORICAL FINANCIAL DATA

**Q. Please describe Exhibit E-1.**

A. Exhibit E-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 electric and electric operations for the year ended September 30, 2024. Schedule 4 is a comparative income statement for Pike’s electric 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 E-1, Schedule 5 in more detail.**

A. Exhibit E-1, Schedule 5, "Statement of Charges Made by Corning Natural Gas Corporation to Pike County Light & Power Company's Electric Operations" is submitted in support of the charges for electric 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 E-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 E-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 E-2 CAPITALIZATION

**Q. Please describe Exhibit E-2.**

A. Exhibit E-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 for September 30, 2025 as shown below:

| | Ratio |
|---|---|
| Long-Term Debt | 40.81% |

| | |
|---|---|
| Short-Term Debt | 8.66% |
| Common Equity | 50.52% |
| 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 forecast ratios of capital being employed by Pike, as set forth on Exhibit E-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 E-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 50.52 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 E-2, Schedule 3, the cost of equity return is 9.75 percent. For revenue requirement purposes, we rounded the return on equity from the Electric 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 E-2, Schedule 3, the overall ROR is 8.37 percent.

## Exhibit E-3 ELECTRIC RATE BASE

**Q. Please describe Exhibit E-3.**

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

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

A. We began with actual electric 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 electric rate base.

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

A. We began with the actual electric 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 E-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 Grandinali provided us with the budgeted electric distribution expenditures and additions scheduled for October 1, 2024 through March 31, 2026 (18 month lookforward) shown on Exhibit E-3, Schedules 10 and 11. Retirements were projected through March 31, 2026. For distribution plant retirements were based on historic levels. The calculated adjustment for distribution plant of $8,792,239 is shown on Exhibit E-3, Schedule 1, page 1 of 4. The adjustment for common general plant allocated to gas of $552,500 is shown on Exhibit E-3, Schedule 1, page 2 of 4.

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

A. Exhibit E-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., 3.32%). Furniture, equipment, and computers were also allocated on that basis.

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

A. As discussed above Exhibit E-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 E-3, Schedule 1, page 1 of 4.

**Q. Please describe the calculation of the accumulated provision for depreciation of electric 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 $1,163,700 for the electric plant reserve is shown on Exhibit E-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 $183,300 is shown on Exhibit E-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 E-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 $548,495 for the twelve months ended September 30, 2025 as shown on Exhibit E-3, Schedule 3, pages 2 and 2. We would note that the working capital requirement for the Twelve Months Ended September 30, 2024 is shown on Exhibit E-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 party provides a product or service, and when that providing party 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 would note that 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 power 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. How was the System Benefits Charge ("SBC") expense reflected?**

A. For purposes of the lead lag calculation both the SBC recoveries and offsetting expense have the same number of lag days (i.e., 30 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 8.0 day lag. Pennsylvania's gross receipts tax and 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 E-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 these items.

**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 mid-point of 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 electric 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 E-3, Schedule 4.

**Q. How did you calculate the prepayments component of electric 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 E-3, Schedule 5.

**Q. Please describe Exhibit E-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. $212,500 of these costs was allocated to electric operations based on a net plant split. On Schedule 6, we calculated the after-tax amount for this item to be approximately $154,500.

**Q. Please describe Exhibit E-3, Schedule 7.**

A. At September 30, 2024, the Company had a negative deferred credit of $15,133 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 movement for this item is forecast to be

$12,700 at September 30, 2025 and is reflected as a rate base addition in Exhibit E-3, Summary.

**Q. Please describe the calculation of customer deposits as shown on E-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 June 30, 2021?**

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

## EXHIBIT E-4 ELECTRIC COST OF SERVICE

**Q. Please describe Exhibit E-4.**

A. Exhibit E-4 consists of a summary and fourteen schedules containing the historic and future electric cost of service. The Accounting Panel supports all schedules with the exception of Schedule 8, which addresses the annual allowance for tree trimming and is supported by Mr. Grandinali. 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 E-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 $1,874,600 shown on page 2 of the Summary was calculated?**

A. We began with the projected September 30, 2025 rate base from Exhibit E-3, Summary. To this balance we applied the overall rate of return shown on Exhibit E-2, Schedule 3. This produced a return of $3,267,107. We compared this number to the earned return projected on page 1, column 4 of the Summary, which was $1,988,700. The difference between these two amounts is $1,278,407, which we factored up for the Pennsylvania gross earnings tax, customer uncollectibles, and income taxes to arrive at a revenue requirement of $1,874,613, which was rounded to $1,874,600.

**Q. Please describe Exhibit E-4, Schedule 1, Page 1 of 3.**

A. Exhibit E-4, Schedule 1, Page 1 of 3 compares the forecast billed electric sales and revenues for the Twelve Months Ended September 30, 2025 to the actual electric sales and revenues for the Twelve Months Ended September 30, 2024. The calculation of the forecast delivery revenues, fuel recoveries, System Benefit Charge and Gross Receipts Tax for the Twelve Months Ended September 30, 2025 come from Exhibit E-5, Schedule 6.

**Q. Please continue with page 2 of Schedule 1.**

A. Exhibit E-3 Schedule 1, page 2 of 3 shows Other Operating Revenues for the Twelve Months Ended September 30, 2024 and 2025. The forecast of Late Payment Charge (“LPC”) and rent from electric property was obtained from our internal forecast of other income for pole billings and other revenues.

**Q. Please continue.**

A. Exhibit E-4, Schedule 1, page 3 of 3, is necessary to match the level of expense associated with the SBC surcharge for the Twelve Months Ended September 30, 2025 to the level included in the Twelve Months Ended September 30, 2024.

**Q. Please describe Exhibit E-4, Schedule 2.**

A. Exhibit E-4, Schedule 2 reflects the change in purchased power expenses and matches projected energy cost recoveries through base rates and the Electric Supply Adjustment Charge ("ECR") for the Twelve Months Ended September 30, 2025.

**Q. Please describe the adjustment to other Purchased Power Cost shown in Exhibit E-4, Schedule 3.**

A. The estimated increase in other Purchased Power Costs shown on Exhibit E-4, Schedule 3 was calculated by applying the actual increase in this expense realized directly from the Orange & Rockland electric bills between the Twelve Months Ended September 30, 2024 and September 30, 2025 of $36,700.

**Q. Please explain the increases in salaries shown in Exhibit E-4, Schedule 4.**

A. Page 1 of Exhibit E-4, Schedule 4 contains the calculation of the annual wage increases. We took both direct and allocated payroll that was charged to Pike's electric 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 E-4, Schedule 4 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, overseeing customer service, and reporting to corporate management on a regular basis. 37.5 percent of the expense portion of the salary for this position

($50,000) was allocated to Pike's electric operations based on the current gas vs. electric customer split. $20,000 will be allocated to Pike Gas 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. The Systems Planner will perform several tasks including planning, scheduling and implementing maintenance and inspection programs on the electric system facilities, approving operations & maintenance contractor time sheets and invoices, designing and coordinating meter operations technician primary and secondary metering for three phase new business or state line metering projects, and serving as a liaison with electric new business and street light applicants and contractors. The estimated annual wages for this employee would be $100,000. 10.0 percent of the expense portion of the salary for this position ($10,000) was allocated to Pike's electric operation, and the remaining $90,000 will be allocated to capital for Pike Electric. There will be no allocation to Pike Gas for this employee.

**Q. Please continue with a description of Adjustment No. (5), Changes in Operation and Maintenance Expense to Reflect the Estimated Increase in Payroll Ancillary Costs and Adjustment No. (13), Changes in Taxes Other Than Income Taxes to Reflect Increases in Payroll Taxes, as shown on Exhibit E-4, Summary, as well as on Exhibit E-4, Schedule 5 and Schedule 13, Page 1, respectively.**

A. The estimated increase in payroll ancillary costs, which amounts to $30,700, was calculated by applying a fringe benefit rate of 36.05% to the forecasted wage increase amounts shown on Exhibit E-4, Schedule 4, Pages 1 and 2, and which were discussed above. 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 increase in Payroll Taxes was calculated by applying the payroll tax rate of 7.65% to the forecasted wage increase amount. 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. (7), Changes in Operation and Maintenance Expenses to reflect the amortization of Storm Deferrals, as shown in Exhibit E-4, Schedule 7.**

A. Adjustment No. (7) in the amount of $29,700 reflects the increase in amortization expense for storm cost over four-years. At September 30, 2025, the Company projects that the deferred Hurricane Riley and other minor storm balance will be approximately $300,865. The annual amortization expense of $75,216 was compared to the level of storm costs charged to expense in the Test Year of $45,528 to calculate the adjustment of $29,688 or $29,700 when rounded.

**Q. Please describe Adjustment No. (8), Changes in Operation and Maintenance (O&M) Expense to Related to Tree Trimming, as shown on Exhibit E-4, Summary, as well as on Exhibit E-4, Schedule 8.**

A. Adjustment No. (8) provides for an increase in O&M expense of $26,800 to normalize the level of contractor tree trimming costs. In the test year, the Company had tree trimming costs of $146,252. The Company is on a five-year cycle for tree trimming and the adjustment increases the Test Year level to reflect the average annual spending for the twelve months ended September 30, 2022, 2023 and 2024 of $173,081.

**Q. Please describe Adjustment No. (9), Changes in Operation and Maintenance Expense to reflect the amortization of estimated rate case expenses, as shown on Exhibit E-4, Schedule 9.**

A. Adjustment No. (9) Represents an increase in O&M expense of $53,100 to reflect a four-year amortization of estimated incremental costs associated with this rate case. As shown on Schedule 9, Pike Electric estimates that it will incur $212,500 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. (10), for intercompany administrative and operating charges, as shown on Exhibit E-4, Summary, as well as on Exhibit E-4, Schedule 10.**

A. The 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 on the Exhibit to $7,800.

**Q. Please address Adjustment No. (11), Exhibit E-4, Schedule 11.**

A. Adjustment No. (11) adjusts the uncollectible expense recorded on the Company's books to reflect the actual 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 $44,997. This expense was compared to the uncollectible accruals recorded during the twelve months ended September 30, 2024, which was an amount of $82,022 to arrive at the negative adjustment of $37,025 or $37,000 rounded.

**Q. Please explain Adjustment (12) to depreciation expense, Exhibit E-4, Schedule 12.**

A. Exhibit E-4, Schedule 12 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 electric 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-2008-2046518.

**Q. Please explain how the adjustment to depreciation expense shown on page of Schedule 12 was calculated.**

A. We started with the electric distribution and common general plant balances allocated to electric at September 30, 2024. To these balances we eliminated non-depreciable plant. We then reflected the plant additions and retirement as shown on Exhibit E-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 $1,358,200. This level was compared to the Test Year level of $1,096,900 and resulted in the depreciation adjustment of $261,300.

**Q. What is the purpose of the depreciation reserve calculations shown at the bottom of page 1 of Exhibit E-4, Schedule 12?**

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

**Q. Are the depreciation, amortization, and net salvage rates shown on pages 2 through 4 the same as contained in the Settlement Agreement approved by the PAPUC in Case R-2013-2397237?**

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 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 enough data at this time. The current allowance of $35,148 is shown on Exhibit E-4, Schedule 12, 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 excess of $16,000, shown on the bottom of Exhibit E-4, Schedule 12, Page 4.**

A. As a result of a previous electric base rate case (Docket No. R-2008-2046518), the Company moved an excess 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 returning that excess depreciation reserve to customers.

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

A. No, we are not.

**Q. Please describe Adjustment No. (13), Changes in Taxes Other, as shown Exhibit E-4, Schedule 13, Page 1.**

A. Adjustment No. (13), in addition to the change to payroll taxes discussed above, reflects the change in the Pennsylvania Gross Earnings Tax for the Twelve Months Ending September 30, 2025 and property taxes. The Gross Earnings Tax was calculated by multiplying electric revenues shown on Exhibit E-4, Summary, page 1, Column 4 by the Gross Receipt tax rate of 5.9 percent. Property tax expense was based on the latest actual tax bills.

**Q. Please describe Adjustment No. (14), Calculation of Income Tax Expense for the Twelve Months Ending June 30, 2021, as shown Exhibit E-4, Schedule 14.**

A. Adjustment No. (14) 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 14.**

A. Page 3 shows the calculation of the interest deduction included in page 1 of Schedule 14. The weighted cost of debt of 7.21 percent comes from Exhibit E-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 E-5 ELECTRIC SALES AND REVENUES

**Q. What were Pike's actual total delivery volumes for the 12 months ended June 30, 2020?**

A. Pike's actual total delivery volumes for the 12 Months Ended September 30, 2024 were 81,167,096 KWHs as shown on Exhibit E-5, Schedule 1. The associated actual monthly billed revenues for the 12 Months Ended September 30, 2024, are shown on Exhibit E-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 84,427,347 KWHs, which is an increase of 3,260,251 KWHs from the 12 months ended September 30, 2024 and reflects a 4.0 percent growth for the period. The calculation of the forecast sales is shown on Exhibit E-5, Schedule 5.

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

A. As shown on Exhibit E-5, Schedule 5, we started with the actual delivery volumes for the Twelve months ended September 30, 2024. We made an adjustment to reflect forecasted growth in residential, commercial and street light sales of 4.0 percent. The projected growth was based on actual growth between the Twelve Months Ended September 30, 2023 and September 30, 2024.

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

A. The projected electric revenues are shown on Exhibit E-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 E-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

Net Book Value of Electric, Gas and Common Plant-in-Service

As of September 30, 2024

Exhibit E-1

Schedule 2

| | 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** | **Exhibit E-1**
**Statement of Income** | **Schedule 3**
**Twelve Months Ending September 30, 2024**

| | 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**
**Statement of Income - Electric**
**Twelve Months Ending September 30, 2024 and 2023**

**Exhibit E-1**
**Schedule 4**

| | September 30 2024 | September 30 2023 |
|---|---|---|
| **Operating Revenues:** | | |
| Residential Sales | $ 6,139,418 | $ 6,390,043 |
| Commercial & Industrial Sales | 7,039,827 | 7,445,456 |
| Public Lighting Sales | 211,526 | 203,981 |
| Total Sales and Delivery of Electricity | 13,390,772 | 14,039,480 |
| Other Operating Revenues: | | |
| Miscellaneous Service Revenues | 28,184 | (2) |
| Rent from Electric Property | (57,902) | 335,040 |
| Other Electric Revenues | 2,976 | - |
| Total Other Electric Revenues | (26,742) | 335,038 |
| Total Electric Operating Revenues | 13,364,029 | 14,374,517 |
| Operating Expenses: | | |
| Purchased Electric Power Costs | 5,187,864 | 6,532,751 |
| Other Power Supply Expenses | 734,868 | 699,876 |
| Distribution Expenses | 773,828 | 521,681 |
| Customer Accounts Expenses | 311,292 | 178,164 |
| Customer Service Expenses | 30,590 | 31,651 |
| Administrative And General Expenses | 2,148,999 | 2,021,843 |
| Depreciation Expense | 1,096,950 | 801,133 |
| Taxes, Other than Income Tax | 560,165 | 915,526 |
| State Income Taxes | (1,319) | 103,014 |
| Federal Income Taxes | 358,680 | 354,714 |
| Total Operating Expense | 11,201,917 | 12,160,353 |
| Total Income from Electric Utility Operations | 2,162,112 | 2,214,165 |
| Taxes - Other Deductions: | | |
| Donations | 2,175 | 3,251 |
| Other Income Deductions | (90,023) | (18,706) |
| Total Taxes - Other Income Deductions | (87,848) | (15,454) |
| Interest Charges: | | |
| Interest on Long Term Debt | 940,571 | 769,600 |
| Amortization of Debt Discount & Expense | 13,644 | 10,538 |
| Other Interest Expense | 28,006 | 94,201 |
| Total Interest Charges | 982,221 | 874,340 |
| Net Income - Electric Operations | $ 1,267,740 | $ 1,355,280 |

**Pike County Light and Power Company** — **Exhibit E-1**
**Statement of Direct and Allocated Charges From Corning Natural Gas Corporation** — **Schedule 5**
**Twelve Months Ending September 30, 2024** — **Page 1 of 2**

| Operation and Maintenance Expenses | | Direct Charges | Allocated Charges | Total Charges |
|---|---|---|---|---|
| Purchased Power Expense | | | | |
| 555 | Purchased Electric Power Costs | $ 6,299,298 | | $ 6,299,298 |
| 555 | Deferred Purchased Power | (1,111,435) | | (1,111,435) |
| 555 | Other Power Supply Expenses | 734,868 | - | 734,868 |
| | Total Power Supply Expense | $ 5,922,732 | $ - | $ 5,922,732 |
| Distribution Expenses - Operation | | | | |
| 580 | Operation Supervision and Engineering | $ 6,725 | $ - | $ 6,725 |
| 581 | Load Dispatching | - | - | - |
| 582 | Station Expenses | 10,670 | - | 10,670 |
| 583 | Overhead Line Expenses | - | - | - |
| 584 | Underground Line Expenses | 5,700 | - | 5,700 |
| 586 | Meter Expenses | - | - | - |
| 587 | Customer Installations Expenses | - | - | - |
| 588 | Miscellaneous Distribution Expenses | 1,962 | - | 1,962 |
| | Total Operation | 25,056 | - | 25,056 |
| Distribution Expenses - Maintenance | | | | |
| 592 | Maintenance of Station Equipment | 4,953 | - | 4,953 |
| 593 | Maintenance of Overhead Lines | $ 412,766 | $ 312,083 | $ 724,848 |
| 594 | Maintenance of Underground Lines | 5,059 | - | 5,059 |
| 595 | Maintenance of Light Transformer | 11,262 | - | 11,262 |
| 597 | Maintenance of Meters | - | - | - |
| 598 | Maintenance of Miscellaneous Distribution Plant | 2,649 | | 2,649 |
| | Total Maintenance | 436,689 | 312,083 | 748,771 |
| | Total Distribution Expenses | $ 461,745 | $ 312,083 | $ 773,828 |
| Customer Accounts Expenses - Operation | | | | |
| 901 | Supervision | | | |
| 902 | Meter Reading Expenses | $ 6,521 | $ - | $ 6,521 |
| 903 | Customer Records & Collection Expenses | 203,994 | - | 203,994 |
| 904 | Uncollectible Accounts | 82,210 | - | 82,210 |
| | Total Customer Accounts Expenses | $ 292,725 | $ - | $ 292,725 |
| Customer Service & Information Expenses - Operation | | | | |
| 908 | Customer Service & Informational Expenses (Non-Major | $ - | | $ - |
| 909 | Supervision | $ - | $ - | $ - |
| 910 | Customer Assistance Expense | $ - | $ - | $ - |
| 911 | Informational Advertising Expenses | $ 11,242 | $ 7,325 | $ 18,567 |
| 912 | Miscellaneous Customer Service Expenses | $ - | $ - | $ - |
| 913 | Rents | $ - | $ - | $ - |
| | Total Customer Service & Informational Expen | $ 11,242 | $ 7,325 | $ 18,567 |
| Sales Expense | | | | |
| 917 | Promotional Advertising Expense | $ 30,590 | | $ 30,590 |
| | Total Customer Service & Inform. Expenses | $ 30,590 | $ - | $ 30,590 |
| Administrative and General Expenses - Operation | | | | |
| 920 | Administrative and General Salaries | $ 235,983 | $ 596,095 | $ 832,078 |
| 921 | Office Supplies and Expenses | 44,999 | 257,334 | 302,333 |
| 922 | Administrative Expenses Transferred - Cr. | (259,863) | - | (259,863) |
| 923 | Outside Services Employed | 197,830 | 192,647 | 390,477 |
| 924 | Property Insurance | (219,214) | 221,118 | 1,904 |
| 925 | Injuries and Damages | 135,677 | | 135,677 |
| 926 | Other Employee Benefit Expenses | 227,965 | 140,165 | 368,130 |
| 928 | Regulatory Commission Expenses | 296,482 | - | 296,482 |
| 930.2 | Miscellaneous General Expenses | 18,594 | - | 18,594 |
| 930.6 | Miscellaneous General Expenses- Vehicle | 10,726 | 18,824 | 29,550 |
| | Total Operation | $ 689,179 | $ 1,426,183 | $ 2,115,362 |
| Administrative and General Expenses - Maintenance | | | | |
| 932 | Maintenance of General Plant | $ 33,637 | | $ 33,637 |
| | Total Maintenance | $ 33,637 | $ - | $ 33,637 |
| | Total Administrative and General Expense | $ 722,816 | $ 1,426,183 | $ 2,148,999 |
| Total Operations and Maintenance | | $ 7,441,850 | $ 1,745,591 | $ 9,187,441 |

**Pike County Light and Power Company** — **Exhibit E-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 |
|---|---|---|---|---|
| Income Statement Accounts | | | | |
| 408.1 | Taxes Other Than Income - Utility | $ 556,171 | $ 3,994 | $ 560,165 |
| 425 | Miscellaneous Amortizations | 17,623 | - | 17,623 |
| 426.1 | Donations | 671 | 1,504 | 2,175 |
| 426.5 | Other Income Deductions - Debt Expense | - | - | - |
| Balance Sheet Accounts | | | | |
| 101 | Electric Plant In Service | 8,541,419 | - | 8,541,419 |
| 108 | Accumulated Provision for Depreciation | 845,377 | - | 845,377 |
| 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 |
| 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 & Maintenance | $ 10,904,002 | $ 5,498 | $ 10,909,500 |
| | Total Charges | $ 18,345,852 | $ 1,751,089 | $ 20,096,941 |

**Pike County Light and Power Company**
Common Expense Allocation

**Exhibit E-1**
**Schedule 6**

| Allocation Factor | | | Applicable Services |
|---|---|---|---|
| A | **Accounts Payable Factors** | | Accounts Payable Processing |
| | CNG | 91.50% | |
| | Pike Electric | 6.14% | |
| | Pike Gas | 1.25% | |
| | Leatherstockimg PA | 1.11% | |
| B | **General Plant Factor** | | |
| | CNG | 97.20% | |
| | Pike Electric | 1.73% | |
| | Pike Gas | 0.35% | |
| | Leatherstockimg PA | 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 | Inventrory/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 E-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

| 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 | 40.81% |
| Average Short Term Debt (a) | | 2,006,792 | 5.10% | | 3,733,122 | 8.66% |
| Proprietary Capital | | | | | | |
| Common Stock | | - | | | - | |
| Paid In Capital | | 12,450,000 | | | 12,450,000 | |
| Retained Earnings | | 7,303,955 | | | 9,318,409 | |
| Total Proprietary Capital: | | 19,753,955 | 50.21% | | 21,768,409 | 50.52% |
| Total Capitalization | $ | 39,345,172 | 100.00% | $ | 43,085,956 | 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 E-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 | 40.81% | 6.80% | | 2.78% | 2.78% |
| Short Term Debt | 8.66% | 7.58% | (a) | 0.66% | 0.66% |
| Common Stock Equity | 50.52% | 9.75% | | 4.93% | 6.83% |
| Total Capitalization | 100.00% | | | 8.37% | 10.27% |

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

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

Exhibit E-3

| Schedule | Title of Schedule | Witness |
|---|---|---|
| Summary | Electric Rate Base | C. Lenns & M. Lenns |
| (1) | Electric Plant - Additions & Retirements | C. Lenns & M. Lenns |
| (2) | Electric Depreciation Reserve - Depreciation Rates | C. Lenns & M. Lenns |
| (3) | Electric 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 Regulatory Assets | C. Lenns & M. Lenns |
| (7) | Changes to Rate Base for Regulatory Liabilities | C. Lenns & M. Lenns |
| (8) | Changes in Customer Deposits | C. Lenns & M. Lenns |
| (9) | Changes in Deferred Income Taxes | C. Lenns & M. Lenns |
| (10) | Electric Capital Expenditures | S. Grandinali |
| (11) | Electric Plant Additions | S. Grandinali |

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



| Description | Actual Per Books at 09/30/24 | Difference Between Historical and Future Years | | Future Year at 09/30/25 | Schedule No. |
|---|---|---|---|---|---|
| | | Reference | Amount | | |
| | (a) | (b) | (c) | (d)=(a)+(c) | |
| Utility Plant: | | | | | |
| Electric Plant in Service | $ 34,737,200 | (1a), (1d) | $ 8,792,239 | $ 43,529,439 | 1 |
| Common Plant in Service (Allocated) | 979,900 | (1b), (1d) | 552,500 | 1,532,400 | 1 |
| General Plant allocated from Corning Gas (Net) | - | (1c) | 204,000 | 204,000 | 1 |
| CWIP not taking interest | 2,567,200 | (1d) | (2,567,200) | - | 1 |
| Total Utility Plant | 38,284,300 | | 6,981,539 | 45,265,839 | |
| Utility Plant Reserves: | | | | | |
| Accumulated Provision For Depreciation of Electric Plant in Service | 4,247,700 | (2a) | 1,163,700 | 5,411,400 | 2 |
| Accumulated Provision For Depreciation of Common Plant in Service (Allocated) | 1,129,300 | (2b) | 183,300 | 1,312,600 | 2 |
| Retirement W.I.P | (63,200) | (2c) | - | (63,200) | 2 |
| Total Utility Plant Reserves | 5,313,800 | | 1,347,000 | 6,660,800 | |
| Net Plant | 32,970,500 | | 5,634,539 | 38,605,039 | |
| Additions to Net Plant | | | | | |
| Working Capital Requirements: | | | | | |
| Cash Working Capital | 1,026,700 | (3) | (478,200) | 548,500 | 3 |
| Materials and Supplies | 1,535,700 | (4) | 32,700 | 1,568,400 | 4 |
| Prepayments | 26,600 | (5) | (100) | 26,500 | 5 |
| Deferred Debits (Net of Tax) | 334,500 | (6) | (32,400) | 302,100 | 6 |
| Total Additions | 2,923,500 | | (478,000) | 2,445,500 | |
| Deductions to Net Plant: | | | | | |
| Deferred Credits (Net of Tax) | (104,600) | (7) | 12,700 | (91,900) | 7 |
| Customer Deposits | 332,400 | (8) | 3,500 | 335,900 | 8 |
| Accumulated Deferred Income Taxes | 1,638,700 | (9) | 134,300 | 1,773,000 | 9 |
| Total Deductions | 1,866,500 | | 150,500 | 2,017,000 | |
| Electric Rate Base | $ 34,027,500 | | $ 5,006,039 | $ 39,033,539 | |

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



| Adjustment Number | Description | Amount |
|---|---|---|
| (1a) | Changes in Electric Plant in Service - Additions & Retirements | $ 8,792,239 |
| (1b) | Changes in Common Plant in Service - Additions & Retirements | 552,500 |
| (1c) | Allocation of Intercompany Plant | 204,000 |
| (1d) | Changes to Construction Work In Progress | (2,567,200) |
| (2a) | Changes to Electric Depreciation Reserve | 1,163,700 |
| (2b) | Changes to Common Plant - Depreciation | 183,300 |
| (2c) | Changes to retirement work in progress | - |
| (3) | Changes in Working Capital Requirements (O&M) | (478,200) |
| (4) | Change in Materials and Supplies | 32,700 |
| (5) | Change in Working Capital Prepayments | (100) |
| (6) | Changes to Rate Base for Deferred Debits | (32,400) |
| (7) | Changes to Rate Base for Deferred Credits | 12,700 |
| (8) | Changes in Customer Deposits | 3,500 |
| (9) | Changes in Deferred Income Taxes | 134,300 |

Pike County Light And Power Company
Statement in Support of Change No. (1) & (2c)
To Electric Plant in Service
For the Twelve Months Ended September 30, 2025



| Electric Plant in Service | | | Amount |
|---|---|---|---|
| **Balance at September 30, 2024** | | | **$ 34,737,200** |
| **Additions - Completed CWIP at September 30, 2024 Change (1d) *** | * | **$ 2,567,239** | |
| Additions - October 1, 2024 thru September 30, 2025 | | 4,300,000 | |
| Additions - October 1, 2025 thru March 31, 2026 | | 2,300,000 | |
| Total Additions | | | 9,167,239 |
| **Electric Retirement Work In Progress at June 30, 2020 (Change No. 2c)** | | - | |
| Retirements - October 1, 2024 thru September 30, 2025 | | (250,000) | |
| Retirements - October 1, 2025 thru March 31, 2026 | | (125,000) | |
| Total Retirements | | | (375,000) |
| **Net Additions (Change No. 1)** | | | **8,792,239** |
| Ending Balance at September 30, 2025 | | | **$ 43,529,439** |

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

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



| Common Plant in Service | | | Total Amount | Electric Allocation 85% |
|---|---|---|---|---|
| **Balance at September 30, 2024** | | | $ 1,152,869 | **$ 979,900** |
| **Additions - Completed CWIP at June 30, 2020 (Change 1d)** | * | **$ -** | | |
| Additions - October 1, 2024 thru September 30, 2025 | | $ 600,000 | | 510,000 |
| Additions - October 1, 2025 thru March 31, 2026 | | 200,000 | | 170,000 |
| Total Additions | | | 800,000 | 680,000 |
| Retirements - October 1, 2024 thru September 30, 2025 | | (100,000) | | (85,000) |
| Retirements - October 1, 2025 thru March 31, 2026 | ** | (50,000) | | (42,500) |
| Total Retirements | | | (150,000) | (127,500) |
| **Net Additions (Change No. 1b)** | | | 650,000 | **552,500** |
| **Ending Balance at September 30, 2025** | | | $ 1,802,869 | **$ 1,532,400** |

* See E-3, Schedule 1, Page 4 of 4
** General Plant, excluding structures, is amortized over 5 - 10 years.

Pike County Light And Power Company
Statement in Support of Change No. (1c)
To Electric 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 Electric | | Electric 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 | 3.32% | = | $ 100,862 |
| | | | | | | | |
| 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 | 3.32% | = | 103,179 |
| | | | | | | | |
| **(Change No. 1c)** | | | | | | | **$ 204,041** |
| | | | | | | | |
| **Rounded** | | | | | | | **$ 204,000** |

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



| CWIP Projects Completed At September 30, 2024 | | Total Amount (A) | Electric Allocation (B) | Electric Plant In-Service (C) = (A) x (B) |
|---|---|---|---|---|
| **Electric Distribution Plant Additions (Change No 1d)** | * | $2,567,239 | 100% | **$ 2,567,200** |
| **General Plant Additions (Change No 1d)** | | - | 85% | **-** |
| **Net Transfers to Plant In-Service (Change No. 1d)** | | | | **$ 2,567,200** |

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

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



| Accumulated Provision for Depreciation of Electric Plant | | Amount |
|---|---|---|
| **Electric Reserve Balance at September 30, 2024** | | **$ 4,247,700** |
| Additions - October 1, 2024 thru September 30, 2025 | $ 966,500 | |
| Additions - October 1, 2025 thru March 31, 2026 | 572,200 | |
| Total Additions | | 1,538,700 |
| | - | |
| Retirements - October 1, 2024 thru September 30, 2025 | (250,000) | |
| Retirements - October 1, 2025 thru March 31, 2026 | (125,000) | |
| Total Retirements | | (375,000) |
| **Net Additions (Change No. 2a)** | | **1,163,700** |
| **Ending Reserve Balance at September 30, 2025** | | **$ 5,411,400** |

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



| Accumulated Provision for Depreciation on Common Plant | | Total Amount | | Electric Allocation 85% |
|---|---|---|---|---|
| **General Plant Reserve Balance at September 30, 2024** | | | $ 1,328,583 | **1,129,300** |
| Additions - October 1, 2024 thru September 30, 2025 | | 222,600 | | |
| Additions - October 1, 2025 thru March 31, 2026 | | 143,000 | | |
| Total Additions | | | 365,600 | 310,800 |
| Retirements - October 1, 2024 thru September 30, 2025 | | (100,000) | | |
| Retirements - October 1, 2025 thru March 31, 2026 | * | (50,000) | | |
| Total Retirements | | | (150,000) | (127,500) |
| **Net Additions (Change No. 2b)** | | | 215,600 | **183,300** |
| **Ending Reserve Balance at September 30, 2025** | | | $ 1,544,183 | **$ 1,312,600** |

Pike County Light And Power Company
Statement In Support of Change No. (3)
Electric Working Capital
Twelve Months Ended September 30, 2024

| | Test Year Amount | (Lead) / Lag Days | Dollar Days |
|---|---|---|---|
| Revenue Recovery | $ 12,600,716 | 21.3 | $ 268,395,252 |
| Pennsylvania Gross Receipts Tax | 790,056 | 21.3 | 16,828,183 |
| | 13,390,772 | 21.3 | 285,223,435 |
| Purchased Power Expenses | 6,299,298 | 10.0 | 62,992,983 |
| Deferred Purchased Power Expense | (1,111,435) | 192.2 | (213,617,713) |
| SBC Expense | 11,204 | 30.0 | 336,107 |
| Salaries & Wages | 396,977 | 8.0 | 3,175,816 |
| 401K Pension Match | 29,740 | 8.0 | 237,919 |
| Employee Welfare Expenses | 395,074 | 23.0 | 9,086,704 |
| Intercompany Charges | 780,177 | 30.0 | 23,405,319 |
| Uncollectible Accounts Accrual | 82,022 | 8.0 | 656,179 |
| Other O&M | 1,569,506 | 23.0 | 36,098,635 |
| Amortizations: | | | - |
| Storm Reserve | 541,921 | - | - |
| Rate Case Costs | - | - | - |
| PUC Assessment | 36,642 | - | - |
| OPEB | - | - | - |
| Insurance | - | - | - |
| Depreciation & Amortization | 1,096,900 | - | - |
| Taxes Other - Payroll | 117,437 | 8.0 | 939,493 |
| - Property Tax | 19,608 | - | - |
| Pennsylvania Gross Receipts Tax | 790,056 | - | - |
| Income Taxes: | | | - |
| Federal Income Tax | (310,952) | 30.0 | (9,328,563) |
| Deferred Federal Income Tax | 321,250 | - | - |
| Corporate Business Tax (State) | (116,765) | 30.0 | (3,502,948) |
| Deferred State Income Tax | 122,228 | - | - |
| Return on Invested Capital | 508,200 | - | - |
| Total Requirement | 11,579,088 | (7.7) | (89,520,069) |
| Net Lag (a) - (b) | | 29.0 | $ 374,743,504 |
| Net Requirement (Net Lag / 365 ) | | | $ 1,026,695 |
| Rounded | | | $ 1,026,700 |

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



| | Rate Year Amount | (Lead) / Lag Days | Dollar Days |
|---|---|---|---|
| Revenue Recovery | 15,878,371 | 21.3 | $ 338,209,313 |
| Pennsylvania Gross Receipts Tax | 995,500 | 21.3 | 21,204,150 |
| | 16,873,871 | 21.3 | 359,413,463 |
| Purchased Power Expenses | 7,964,400 | 10.0 | 79,644,000 |
| SBC Expense | 11,204 | 30.0 | 336,107 |
| Salaries & Wages | 482,104 | 8.0 | 3,856,832 |
| 401K Pension Match | 31,902 | 8.0 | 255,216 |
| Employee Welfare Expenses | 423,591 | 23.0 | 9,742,584 |
| Intercompany Charges | 780,177 | 30.0 | 23,405,319 |
| Uncollectible Accounts Accrual | 47,247 | 8.0 | 377,975 |
| Other O&M | 1,686,876 | 23.0 | 38,798,138 |
| Amortizations: | - | | - |
| Storm Reserve | 300,865 | - | - |
| Rate Case Costs | - | - | - |
| PUC Assessment | 36,642 | - | - |
| Insurance | - | - | - |
| Depreciation & Amortization | 1,358,200 | - | - |
| Taxes Other - Payroll | 36,881 | 8.0 | 295,048 |
| - Property Tax | 18,338 | - | - |
| Pennsylvania Gross Receipts Tax | 995,500 | - | - |
| Income Taxes: | | | - |
| Federal Income Tax | 56,840 | 30.0 | 1,705,215 |
| Deferred Federal Income Tax | 60,213 | - | - |
| Corporate Business Tax (State) | 26,544 | 30.0 | 796,333 |
| Deferred State Income Tax | 22,910 | - | - |
| Return on Invested Capital | 1,122,700 | - | - |
| Total Requirement | 15,463,134 | 10.3 | 159,212,767 |
| Net Lag | | 11.0 | $ 200,200,696 |
| Net Requirement (Net Lag / 365 ) | | | $ 548,495 |
| Historical Cash Working Capital | | | 1,026,700 |
| Net Change | | | $ (478,205) |
| Rounded | | | $ (478,200) |

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

Exhibit E-3
Schedule 4

| Month | | Materials & Supplies Inventory Acct 150020 | Electric Allocatoin |
|---|---|---|---|
| | | (1) | (2) |
| October 31, 2023 | Actual | 1,846,765 | $ 1,569,750 |
| November 30, 2023 | Actual | 1,797,373 | 1,527,767 |
| December 31, 2023 | Actual | 1,803,696 | 1,533,141 |
| January 31, 2024 | Actual | 1,706,599 | 1,450,609 |
| February 29, 2024 | Actual | 1,736,717 | 1,476,210 |
| March 31, 2024 | Actual | 1,778,928 | 1,512,089 |
| April 30, 2024 | Actual | 1,781,018 | 1,513,866 |
| May 31, 2024 | Actual | 1,811,206 | 1,539,525 |
| June 30, 2024 | Actual | 1,817,367 | 1,544,762 |
| July 31, 2024 | Actual | 1,857,767 | 1,579,102 |
| August 31, 2024 | Actual | 1,843,697 | 1,567,142 |
| September 30, 2024 | Actual | 1,899,337 | 1,614,436 |
| October 31, 2024 | Actual | 1,897,232 | 1,612,647 |
| November 30, 2024 | Actual | 2,207,948 | 1,876,756 |
| October 2023 - September 30, 2024 Total | | $ 21,680,469 | $ 18,428,399 |
| September 30, 2024 - Twelve Month Average | | $ 1,806,706 | $ 1,535,700 |
| Rounded | | | $ 1,535,700 |
| December 2023 - November 2024 Total | | $ 22,141,511 | $ 18,820,285 |
| Twelve Month Average | | $ 1,845,126 | $ 1,568,357 |
| Rounded | | | $ 1,568,400 |
| Net Changes (Change No. 4) | | | 32,700 |
| Twelve Month Average September 30, 2025 | | | $ 1,568,400 |

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

Exhibit E-3
Schedule 5

| Month | | PaPUC Assessment Acct. 05 165201 | Common Property Tax Acct. 05 165110 | Common Property Insurance Acct. 05 165030 | Total |
|---|---|---|---|---|---|
| October 31, 2023 | Actual | 31,840 | $ 10,799 | $ - | 42,639 |
| November 30, 2023 | Actual | 28,946 | 9,395 | - | 38,341 |
| December 31, 2023 | Actual | 26,051 | 7,992 | - | 34,043 |
| January 31, 2024 | Actual | 23,157 | 6,588 | - | 29,745 |
| February 29, 2024 | Actual | 20,262 | 9,870 | - | 30,132 |
| March 31, 2024 | Actual | 17,368 | 8,467 | - | 25,834 |
| April 30, 2024 | Actual | 14,473 | 7,048 | - | 21,521 |
| May 31, 2024 | Actual | 11,578 | 5,630 | - | 17,208 |
| June 30, 2024 | Actual | 8,684 | 4,211 | - | 12,895 |
| July 31, 2024 | Actual | 5,789 | 14,498 | - | 20,287 |
| August 31, 2024 | Actual | 2,895 | 12,015 | - | 14,910 |
| September 30, 2024 | Actual | 36,642 | 10,561 | - | 47,203 |
| October 31, 2024 | Actual | 33,311 | 9,106 | - | 42,417 |
| November 30, 2024 | Actual | 29,980 | 7,651 | - | 37,631 |
| October 2023 - September 30, 2024 Total | | $ 227,685 | $ 107,073 | $ - | $ 334,757 |
| September 30, 2024 - Twelve Month Average | | $ 18,974 | $ 8,923 | $ - | $ 27,896 |
| x Electric Allocation | | 100% | 85% | 85% | - |
| Electric Twelve Month Average | | $ 18,974 | $ 7,585 | $ - | $ 26,559 |
| Rounded | | | | | $ 26,600 |
| December 2023 - November 2024 Total | | $ 230,189 | $ 103,637 | $ - | $ 333,826 |
| Twelve Month Average | | $ 19,182 | $ 8,636 | $ - | $ 27,819 |
| x Electric Allocation | | 100% | 85% | 85% | - |
| Electric Twelve Month Average | | $ 19,182 | $ 7,341 | $ - | $ 26,523 |
| Rounded | | | | | $ 26,500 |
| Net Changes (Change No. 5) | | | | | (100) |
| Twelve Month Average September 30, 2025 | | | | | $ 26,500 |

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

| Deferred Debit Items | Hurricane Riley Acct 05 186025 | Rate Case (a) Acct 186171 | Total | Total After Tax (b) | Rounded |
|---|---|---|---|---|---|
| Deferred Debit Balance as of September 30, 2024 | $ 346,393 | $ 113,857 | $ 460,250 | $ 334,546 | $ 334,500 |
| Deferred Charges 10/1/2024 - 9/30/2025 (a) | - | 212,500 | 212,500 | 154,462 | 154,500 |
| Less: Amortization of Deferred Charges 10/1/24 - 9/30/25 | (195,528) | (61,613) | (257,141) | (186,910) | (186,900) |
| Deferred Debit Balance as of September 30, 2025 | 150,865 | 264,745 | 415,610 | 302,098 | 302,100 |
| Net Change 7/1/2020 - 6/30/2021 | | | | | $ (32,400) |

(a) See Exhibit E-4, Schedule 8 for estimated rate case expenditures

(b) Calculation of After Tax Factor:

| | | |
|---|---|---|
| | SIT Rate = | 7.9900% |
| + | FIT Rate = | 21.0000% |
| + | SIT Rate Net of FIT Rate [9.99% x (1-21%)] = | 6.3121% |
| = | Effective Net FIT / SIT Rate = | 27.3121% |
| | Net of SIT & FIT Multiplier (1/1-28.8921%) | 72.6879% |

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

Exhibit E-3
Schedule 7

| Deferred Credit Items | FIT Tax Benefits Currently Accruing to Customers Acct. 186150 | FIT Tax Rate Change Accts. 253911 & 253921 | FIT Tax Rate Change Accts. 253911 & 253921 | After Tax * | Rounded |
|---|---|---|---|---|---|
| Deferred Credit Balance as of September 30, 2024 | $ (15,133) | $ (128,752) | $ (143,885) | $ (104,587) | $ (104,600) |
| Deferred Credits 10/1/2024 - 9/30/2025 | - | | - | - | - |
| Less: Amortization of Deferred Charges 10/1/2024 - 9/30/2025 | - | 17,420 | 17,420 | 12,662 | 12,700 |
| Negative Deferred Credit Balance as of September 30, 2025 | $ (15,133) | $ (111,332) | $ (126,465) | $ (91,925) | $ (91,900) |
| Net Change | | | | | $ 12,700 |

| | Calculation of After Tax Factor: | |
|---|---|---|
| * | SIT Rate = | 7.9900% |
| + | FIT Rate = | 21.0000% |
| + | SIT Rate Net of FIT Rate [9.99% x (1-21%)] = | 6.3121% |
| = | Effective Net FIT / SIT Rate = | 27.3121% |
| | Net of SIT & FIT Multiplier (1/1-28.8921%) | 72.6879% |

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

Exhibit E-3
Schedule 8

| Month | | Customer Deposits Acct 235000 | Electric Allocation |
|---|---|---|---|
| | | (1) | (2) |
| October 31, 2023 | Actual | $ 365,513 | $ 310,686 |
| November 30, 2023 | Actual | 384,614 | 326,922 |
| December 31, 2023 | Actual | 387,605 | 329,465 |
| January 31, 2024 | Actual | 391,875 | 333,094 |
| February 29, 2024 | Actual | 391,681 | 332,929 |
| March 31, 2024 | Actual | 393,088 | 334,125 |
| April 30, 2024 | Actual | 396,434 | 336,969 |
| May 31, 2024 | Actual | 396,700 | 337,195 |
| June 30, 2024 | Actual | 397,597 | 337,958 |
| July 31, 2024 | Actual | 397,190 | 337,612 |
| August 31, 2024 | Actual | 393,769 | 334,704 |
| September 30, 2024 | Actual | 395,955 | 336,562 |
| October 31, 2024 | Actual | 400,461 | 340,392 |
| November 30, 2024 | Actual | 399,078 | 339,216 |
| October 2023 - September 30, 2024 Total | | $ 4,692,025 | $ 3,988,221 |
| September 30, 2024 - Twelve Month Average | | $ 391,002 | $ 332,352 |
| Rounded | | | $ 332,400 |
| December 2023 - November 2024 Total | | $ 4,741,437 | $ 4,030,221 |
| Twelve Month Average | | $ 395,120 | $ 335,852 |
| Rounded | | | $ 335,900 |
| Net Changes (Change No. 4) | | | 3,500 |
| Twelve Month Average September 30, 2025 | | | $ 335,900 |

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 E-3
Schedule 9

| Accumulated Deferred Income Taxes | | Balance Accounts 282012 / 282082 |
|---|---|---|
| Balance at September 30, 2024 | | $ 1,638,700 |
| Additions - October 1, 2024 thru September 30, 2025 | | |
| Tax Depreciation - Normalized | 1,560,756 | |
| Less: Book Depreciation | 1,155,710 | |
| Net Schedule M Tax Deduction | 405,046 | |
| x Effective SIT / FIT Tax Rate | 27.3121% | |
| Net Additions October 1, 2024 thru September 30, 2025 | | 110,600 |
| Additions - October 1, 2025 thru March 31, 2026 | | |
| Tax Depreciation - Normalized | 780,378 | |
| Less: Book Depreciation | 693,750 | |
| Net Schedule M Tax Deduction | 86,628 | |
| x Effective SIT / FIT Tax Rate | 27.3121% | |
| Net Additions October 1, 2025 thru March 31, 2026 | | 23,700 |
| Net Additions (Change No. 7) | | $ 134,300 |
| Ending Balance at September 30, 2025 | | $ 1,773,000 |

Pike County Light And Power Company
Electrical Capital Expenditures
For the Twelve Months Ended September 30, 2025
$000's

Exhibit E-3
Schedule 10

| Electric Plant Account | FERC Account | Close Out To Plant In Service | Annual Spending January 2025 - December 2025 | Annual Spending January 2026 - December 2026 | Total |
|---|---|---|---|---|---|
| **LTIIP Program:** | | | | | |
| Additional Defective Pole Replacement and Storm Hardening | 364 | Monthly | $ 1,225 | $ 1,363 | $ 2,588 |
| 69 x 34.5 kV Substation | 366 | Monthly | 1,150 | 3,650 | 4,800 |
| Purchase 69 kV x 34.5 kV-35MVA SubTransformer (for 2027 LTIIP program) | 367 | Monthly | 250 | 750 | 1,000 |
| PJM Interconnect 69kv Line | 368 | Monthly | - | 500 | 500 |
| State Grants | | Monthly | (700) | (2,450) | (3,150) |
| **Subtotal LTIP** | | | **$ 1,925** | **$ 3,813** | **$ 5,738** |
| **Recurring Capital Budget Upgrades / Replacements** | | | | | |
| Station Equipment | 362 | Monthly | $ 263 | $ 276 | $ 538 |
| Residential Meters | 364 | Monthly | 21 | 22 | 43 |
| Electric Light & Substation Upgrades | 368 | Monthly | 32 | 33 | 65 |
| Services-O/H | 369 | Monthly | 63 | 86 | 149 |
| Meters-EM Purchases | 370 | Monthly | 1,728 | 400 | 2,129 |
| | | | | | - |
| **Subtotal Recurring Upgrades / Replacements** | | | **$ 2,106** | **$ 817** | **$ 2,923** |
| **Total Electric Plant Construction Spending** | | | **$ 4,031** | **$ 4,630** | **$ 8,661** |
| **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 | 231 | 249 | 480 |
| Tools, Shop and Garage Equipment | 394 | Monthly | 24 | 25 | 49 |
| Total General Plant Construction Spending | | | **$ 712** | **$ 489** | **$ 1,201** |

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

Exhibit E-3
Schedule 11

| Electric Plant Account | FERC Account | In Service Date | October 2024 - September 2025 | October 2025 - March 2026 | Total |
|---|---|---|---|---|---|
| **LTIIP Program:** | | | | | |
| Additional Defective Pole Replacement and Storm Hardening | 364 | Monthly | $ 1,294 | $ 681 | $ 1,975 |
| 69 x 34.5 kV Substation | 366 | Monthly | 2,400 | 1,825 | 4,225 |
| Purchase 69 kV x 34.5 kV-35MVA SubTransformer (for 2027 LTIIP program) | 367 | Monthly | 500 | 375 | 875 |
| PJM Interconnect 69kv Line | 368 | Monthly | 250 | 250 | 500 |
| State Grants | | Monthly | (1,575) | (1,225) | (2,800) |
| **Subtotal LTIP** | | | **$ 2,869** | **$ 1,906** | **$ 4,775** |
| **Recurring Capital Budget Upgrades / Replacements** | | | | | |
| Station Equipment | 362 | Monthly | $ 269 | $ 138 | $ 407 |
| Residential Meters | 364 | Monthly | 22 | 11 | 33 |
| Electric Light & Substation Upgrades | 368 | Monthly | 32 | 17 | 49 |
| Services-O/H | 369 | Monthly | 75 | 43 | 118 |
| Meters-EM Purchases | 370 | Monthly | 1,064 | 200 | 1,264 |
| **Subtotal Recurring Upgrades / Replacements** | | | **$ 1,462** | **$ 409** | **$ 1,870** |
| **Total Electric Plant Construction Spending** | | | **$ 4,331** | **$ 2,315** | **$ 6,646** |
| **Rounded** | | | **$ 4,300** | **$ 2,300** | **$ 6,600** |
| 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 | 240 | 125 | 365 |
| Tools, Shop and Garage Equipment | 394 | 12/31/2020 | 25 | 13 | 37 |
| Total General Plant In Service | | | **$ 601** | **$ 245** | **$ 845** |
| Rounded | | | **$ 600** | **$ 200** | **$ 800** |

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

| Schedule | Title of Schedule | Witness |
|---|---|---|
| Summary | Electric Cost of Service | C. Lenns & M. Lenns |
| (1) | Changes to Adjust for Sales Growth | C. Lenns & M. Lenns |
| (2) | Changes in Purchased Power Energy Costs | C. Lenns & M. Lenns |
| (3) | Changes in Purchased Power Supply Expense | C. Lenns & M. Lenns |
| (4) | Changes to Reflect Increase in Wages & Salaries and for additional employees | C. Lenns & M. Lenns |
| (5) | Changes to reflect increases in Payroll Ancillary Costs | C. Lenns & M. Lenns |
| (6) | Changes in Operation and Maintenance Expenses to reflect elimination of the amortization of Deferred Post Retiree Expense Other Than Pension Costs (OPEB) | C. Lenns & M. Lenns |
| (7) | Changes in Operation and Maintenance Expense to Reflect Amortization of Storm Deferrals | C. Lenns & M. Lenns |
| (8) | Changes in Operation and Maintenance Expense to Reflect additional O&M expense related to Tree-Trimming | S. Grandinali |
| (9) | Changes in Operation and Maintenance Expense to Reflect Recovery of Rate Case Expense | C. Lenns & M. Lenns |
| (10) | Changes in Operation and Maintenance Expense to Reflect true-up of Joint Use Operating Expense | C. Lenns & M. Lenns |
| (11) | Changes in Operation and Maintenance Expense to Reflect uncollectible expenses | C. Lenns & M. Lenns |
| (12) | Changes in Depreciation Expenses - Plant additions at existing and proposed rates and for net salvage | C. Lenns & M. Lenns |
| (13) | Changes in Taxes Other than income to reflect Changes in Payroll Tax, Gross Earnings Tax and STAS recoveries | C. Lenns & M. Lenns |
| (14) | Calculation of Income Tax Expense | C. Lenns & M. Lenns |

Pike County Light And Power Company
Electric 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 Electricity - Retail Sales | $ 13,390,800 | (1a) | $ 2,721,000 | $ 16,111,800 | $ 1,874,600 | $ 17,986,400 |
| Other Operating Revenues | (26,700) | (1b) | 151,800 | 125,100 | - | 125,100 |
| Total Operating Revenues | 13,364,100 | | 2,872,800 | 16,236,900 | 1,874,600 | 18,111,500 |
| | | | 172,081 | 972,590 | | |
| Operating Expenses: | | | | | | |
| Purchased Electric Power Costs | 5,187,900 | (2) | 2,776,500 | 7,964,400 | - | 7,964,400 |
| Other Power Supply Expenses | 734,900 | (3) | 36,700 | 771,600 | | 771,600 |
| Deferred Purchased Power Expense | | | | | | |
| Other Operation and Maintenance Expenses | 3,264,700 | (1c) | (13,300) | 3,447,700 | 5,200 | 3,452,900 |
| | | (4a) | 25,100 | | | |
| | | (4b) | 60,000 | | | |
| | | (5) | 30,700 | | | |
| | | (6) | - | | | |
| | | (7) | 29,700 | | | |
| | | (8) | 26,800 | | | |
| | | (9) | 53,100 | | | |
| | | (10) | 7,800 | | | |
| | | (11) | (36,900) | | | |
| Depreciation Expense | 1,096,900 | (12a) | 261,300 | 1,358,200 | - | 1,358,200 |
| | | (12b) | - | | | |
| Taxes other than Income | 560,200 | (13) | 456,200 | 1,016,400 | 110,600 | 1,127,000 |
| Total Operating Expenses | 10,844,600 | | 3,713,700 | 14,558,300 | 115,800 | 14,674,100 |
| Operating Income Before Income Taxes: | 2,519,500 | | (840,900) | 1,678,600 | 1,758,800 | 3,437,400 |
| State Income Tax | 5,300 | (14) | (96,000) | (90,700) | 140,500 | 49,800 |
| Federal Income Tax | 12,800 | (14) | (232,200) | (219,400) | 339,800 | 120,400 |
| Operating Income after Taxes | $ 2,501,400 | | $ (512,700) | $ 1,988,700 | $ 1,278,500 | $ 3,267,200 |
| Rate Base | $ 34,027,500 | | $ 5,006,039 | $ 39,033,539 | $ - | $ 39,033,539 |
| Rate of Return | 7.35% | | | 5.09% | | 8.37% |

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

| | | Amount |
|---|---|---|
| Rate base at 09/30/2025 | | $ 39,033,539 |
| Rate of Return at 09/30/2025 | | 8.37% |
| Total Return Required | | 3,267,107 |
| Total Earned Return (Per Exhibit E-4, Summary, Page 1 of 3) | | 1,988,700 |
| Addition Return Required | | 1,278,407 |
| Multiplied by Retention Factor* | | 1.4664 |
| Total Revenue Requirement | | $ 1,874,613 |
| Rounded | | $ 1,874,600 |
| * Retention Factor: | | |
| Additional Revenue | 100.0000 | 1,874,600 |
| Less: Revenue Taxes @ 5.9% | 5.9000 | 110,600 |
| Less: Uncollectibles | 0.2800 | 5,200 |
| | 93.8200 | 1,758,800 |
| Less: State Income Tax @ 7.99% | 7.4962 | 140,500 |
| | 86.3238 | 1,618,300 |
| Less: Federal Income Tax @ 21% | 18.1280 | 339,800 |
| Retention Factor | 68.1958 | 1,278,500 |
| | 1.0000 | |
| | 0.6820 | |
| | 1.4664 | |

| Adjustment Number | Description | Amount |
|---|---|---|
| (1a) | Change in forecast Billed Revenues | $ 2,721,000 |
| (1b) | Change in forecast Other Operating Revenues | 151,800 |
| (1c) | Change In SBC expense | (13,300) |
| (2) | Change in Purchased Power Supply Expense | 2,776,500 |
| (3) | Change in Power Supply Expense | 36,700 |
| (4a) | Changes in Operations and Maintenance Expenses to Reflect Increase in Wages and Salaries | 25,100 |
| (4b) | Changes in Operations and Maintenance Expenses to Reflect Additional Employee Positions | 60,000 |
| (5) | Changes in Operation and Maintenance Expense to Reflect Estimated Payroll Ancillary Costs -- Health Insurance, Workers Comp, 401K Match | 30,700 |
| (6) | Changes in Operation and Maintenance Expense to Reflect Elimination of Deferred Premerger Pension /OPEB costs from rates | - |
| (7) | Changes in Operation and Maintenance Expense to Reflect Amortization of Storm Deferrals | 29,700 |
| (8) | Changes in Operation and Maintenance Expense to Reflect additional O&M expense related to Tree-Trimming | 26,800 |
| (9) | Changes in Operation and Maintenance Expense to Reflect Recovery of Rate Case Expense | 53,100 |
| (10) | Changes in Operation and Maintenance Expense - Intercompany Administrative & Operating Charges | 7,800 |
| (11) | Change in Uncollectible Expense | (36,900) |
| (12a) | Changes in Depreciation Expense -- At Existing & Proposed Rates | 261,300 |
| (12b) | Changes in Depreciation Expense -- Annual allowance for Net Salvage / Amortization of Reserve Excess Case R-2008-2046518 | - |
| (13a) | Changes in Taxes Other than income to reflect Changes in Payroll Tax, Gross Earnings Tax and STAS recoveries | 456,200 |
| (14) | Calculation of Income Tax Expense for the Twelve Months Ended June 30, 2020 | |
| | State Income Tax Adjustment | (96,000) |
| | Federal Income Tax Adjustment | (232,200) |

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

Exhibit E-4
Schedule 1
Page 1 of 3

| 12 Months Ended September 30, 2025 | | Revenues | KWHR Sales | Average cents / per kWHR |
|---|---|---|---|---|
| Delivery Revenue -- Retail Customers | | 7,655,528 | 84,427,347 | 0.0907 |
| Recovery of Purchased Power Costs | | 8,456,217 | | |
| SBC Recoveries | | - | | |
| DSIC Revenue | | - | | |
| Tax Cuts & Jobs Act (TCJA) Credit | | - | | |
| Gross Receipts Tax | | - | | |
| Total | | $ 16,111,744 | 84,427,347 | |
| | | | | |
| 12 Months Ending September 30, 2024 | | | | |
| Delivery Revenue -- Retail Customers | | 7,376,474 | 81,167,096 | 0.0909 |
| Recovery of Purchased Power Costs | | 5,505,804 | | |
| SBC Recoveries | | 13,286 | | |
| DSIC Revenue | | 496,641 | | |
| STAS | | (18,700) | | |
| Sales Tax and Other | | 17,267 | | |
| Total | (a) | $ 13,390,772 | 81,167,096 | |
| | | | | |
| Increase / (Decrease) in Revenues / Sales | | $ 2,720,972 | 3,260,251 | |
| | | | | |
| Rounded | | $ 2,721,000 | | |
| | | | | |
| Percentage Increase / (Decrease) Sales | | | 4.0% | |
| | | | - | |

(a) Rounded = $13,390,800 shown on Exhibit E-4 Summary

Pike County Light And Power Company
Statement in Support of Change No. (1b)
To Adjust For Other Operating Revenue
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-Electric | $ 28,184 | $ 11,082 | $ (17,102) |
| Rent from Electric Property | (57,902) | 113,951 | 171,853 |
| Other Electric Revenues | | | |
| - Other Miscellaneous Sales Adjustments | 2,976 | - | (2,976) |
| Total Other Electric Revenues | (26,742) | 125,033 | $ 151,776 |
| **Rounded (Change 1b)** | $ (26,700) | $ 125,000 | **$ 151,800** |

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

| SBC Expense (Sched 1, Page 1) | |
|---|---|
| Twelve Months Ended September 30, 2025 | $ - |
| Twelve Months Ended September 30, 2025 | 13,286 |
| Net Change | $ (13,286) |
| **Rounded (Change 1c)** | $ (13,300) |

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

Exhibit E-4
Schedule 2

| Power Supply Expense | September 30, 2024 | September 30, 2025 | Net Change |
|---|---|---|---|
| Power Supply Expense - Energy & Capacity | $ 4,276,294 | $ 5,066,205 | $ 789,911 |
| Service Fee | 38,016 | 39,924 | 1,908 |
| Met-Ed | 115,772 | 114,842 | (930) |
| Hedging Cost | 1,394,310 | 1,090,189 | (304,121) |
| Renewable Energy Credit | 419,840 | 599,503 | 179,663 |
| DSP - Consultant Fees | 48,000 | 48,000 | - |
| Total Recoverable Fuel | 6,292,232 | 6,958,662 | 666,431 |
| Deferred Purchased Power Expense | (1,111,435) | 998,648 | 2,110,083 |
| Net Purchased Power Expense | $ 5,180,797 | $ 7,957,310 | $ 2,776,513 |
| Change in Purchased Power Expense (3) Rounded | $ 5,180,800 | $ 7,957,300 | $ 2,776,500 |

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

Exhibit E-4
Schedule 3

| | | |
|---|---|---|
| Other Power Supply Expense - Twelve Months Ended September 30, 2025<br>Account 05 555010 | 771,612 | |
| Other Power Supply Expense - Twelve Months Ended September 30, 2024<br>Account 05 555010 | 734,868 | |
| Annual Increase in Other Power Supply Expense | | $ 36,744 |
| Rounded | | $ 36,700 |

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



| Wage and Salary Increases | | |
|---|---|---|
| - Pike Gas Payroll Expense for Twelve Months Ended September 30, 2024 | $ 255,762 | |
| - Administrative Payroll allocated from Corning Gas Corporation | 141,214 | |
| - Total Electric Payroll Expense | $ 396,977 | |
| - Electric Payroll excluding May 2024 Wage Increase | $ 381,098 | |
| - Annualization of May 2024 Wage & Salary Increases (4% x 7 month / 12 months) | | 8,892 |
| - Total Electric Payroll Expense (see above | $ 396,977 | |
| - Plus annualization of May 2024 Wage Increases (4% x 3 month / 12 months) | 8,892 | |
| Annualized Test Year Wages | $ 405,869 | |
| - October 2025 Wage Increase (4%) | | 16,235 |
| Wage & Salary Wage Increases | | $ 25,127 |
| Rounded | | $ 25,100 |

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



| Material Management Position | | |
|---|---|---|
| Annual Salary for New Positions | $ | 240,000 |
| Additional employee positions applicable to electric operation and maintenance expense | | 25.0% |
| Total Additional Employees Applicable to Pike Gas O&M Expense | $ | 60,000 |
| Rounded Total | $ | 60,000 |

| Job Title Description | Hire Date | Estimated Salary | Cost Allocated To: Pike Elect O&M | | Cost Allocated To: Electric Salary |
|---|---|---|---|---|---|
| Pike - Assistant General Manager | Apr-25 | $ 140,000 | 35.7% | (a) | $ 50,000 |
| Pike - Systems Planner | Apr-25 | 100,000 | 10.0% | (b) | 10,000 |
| | | $ 240,000 | 25.0% | | $ 60,000 |

(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. (5)
To Operations and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 5

| | | | | |
|---|---|---|---|---|
| **Change in Payroll Ancillary Costs (Health Insurance & Workers Compensation)** | | | | |
| Wage Increase and Annualization [1] | $ 25,100 | | | |
| Additional Staffing | 60,000 | | | |
| Total Increases in Wage and Salaries | $ 85,100 | | | |
| x Test Year 401K Pension Match Rate | | 2.54% | $ | 2,162 |
| x Test Year Health & Life Insurance Rate | | 22.02% | | 18,735 |
| s Test Year Workers Compensation Rate | | 11.49% | | 9,781 |
| Total Benefit Costs | | | $ | 30,679 |
| Rounded Total | | | $ | 30,700 |

[1] Per Exhibit E-4, Schedule 4, page 1

Pike County Light And Power Company
Statement in Support of Change No. (6)
To Eliminate The Amortization of OPEB Expense
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 6

| Change in Amortization of OPEB Costs | |
|---|---|
| Annual amortization of OPEB Costs - Twelve Months Ended September 30, 2024 | $ - |
| Annual amortization of OPEB Costs - Twelve Months Ended September 30, 2025 | - |
| Change No. (6) | $ - |
| Rounded Total | $ - |

Pike County Light And Power Company
Statement in Support of Change No. (7)
To Reflect Amortization of Storm Deferrals
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 7

| | $ Amount | | |
|---|---|---|---|
| **Amortization of Storm Deferral Balances** | Balance At 9/30/2023 | Amortization 10/1/23 - 9/30/24 | Balance At 9/30/2024 |
| Deferred Storm Balance | | | |
| - Riley | $ 541,921 | (195,528) | $ 346,393 |
| - Minor Storms (future estimate) | - | 150,000 | 150,000 |
| | - | - | - |
| Total | $ 541,921 | $ (45,528) | 496,393 |
| Amortization 10/1/24 - 9/30/25 | | | (195,528) |
| Unrecovered Balance at 9/30/2025 | | | 300,865 |
| Recovery Period (Years) | | | 4 |
| Annual Amount to be Amortized | | | $ 75,216 |
| Less: Annual amortization of Deferred Storm Charges In Twelve Months Ended September 30, 2024 | | | (45,528) |
| Net Increase | | | $ 29,688 |
| Rounded | | | $ 29,700 |

Pike County Light And Power Company
Statement in Support of Change No. (8)
To Reflect Additional Expense Related to Tree-Trimming
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 8

| Tree-Trimming | | |
|---|---|---|
| Actual Spending -Fiscal Year Ended 9/30/2022 | $ 165,555 | |
| Actual Spending -Fiscal Year Ended 9/30/2023 | $ 99,414 | |
| Actual Spending -Fiscal Year Ended 9/30/2024 | 254,273 | |
| Total | $ 519,242 | |
| Average Annual Tree Trimming Expenditures | | $ 173,081 |
| Actual Tree-Trimming Charges for Twelve Months Ended September 30, 2024 | | 146,252 |
| Net Adjustment | | $ 26,829 |
| Increase (rounded) | | $ 26,800 |

Pike County Light And Power Company
Statement in Support of Change No. (9)
Rate Case Costs
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 9

Adjustment to Other Operations & Maintenance Expense to Reflect Rate Case Costs

| | | |
|---|---|---|
| Estimated Rate Case Costs | $ | 250,000 |
| 2025 Percentage Applicable to Electric | | 85.00% |
| Estimated Rate Case Costs applicable to Electric | $ | 212,500 |
| / Amortization Period - Years | | 4 |
| Annual Rate Case Expense | $ | 53,125 |
| Rounded | $ | 53,100 |

Pike County Light And Power Company
Statement in Support of Change No. (10)
To Electric Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 10

| 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. (11)
To Uncollectible Operation and Maintenance Expense
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 11

| Uncollectible Accounts Expense | | |
|---|---|---|
| Operating Revenues Before Rate Change -- Twelve Months Ended September 30, 2025 | $ | 16,111,800 |
| Uncollectible write-offs / revenues percentage-- Twelve Months Ended September 30, 2024 | | 0.28% |
| Uncollectible Expense for Twelve Months Ending September 30, 2025 | $ | 45,113 |
| | | |
| Less: Negative Uncollectible Expense reflected in Operation And Maintenance Expense for the Twelve Months Ended September 30, 2024 (FERC 9040) | | 82,022 |
| | | |
| Net Change in Uncollectable Expense | $ | (36,909) |
| | | |
| Rounded Total | $ | (36,900) |

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

| | Amount | | | |
|---|---|---|---|---|
| | Electric Dist. Plant | Common Gen'l Plant Allocated | Total Electric | Adjustment |
| Electric Distribution Plant in Service | | | | |
| At September 30, 2024 Per Exhibit E-3, Schedule 12 | $ 34,737,197 | $ 1,244,289 | $ 35,981,486 | |
| Less: Acquisition Adjustment | - | - | - | |
| Electric Plant at June 30, 2020 | $ 34,737,197 | $ 1,244,289 | $ 35,981,486 | |
| Less: Non-Depreciable Plant | (1,087,646) | (264,350) | (1,351,996) | |
| Depreciable Plant at June 20, 2020 | 33,649,551 | 979,939 | 34,629,490 | |
| Additions - October 1, 2024 thru September 30, 2025 | | | | |
| Distribution - Completed CWIP at 9/30/2025 | 2,567,239 | - | 2,567,239 | |
| Distribution / General Additions Plant | 4,300,000 | 510,000 | 4,810,000 | |
| Additions - October 1, 2025 thru March 31, 2026 | | | | |
| Distribution / General Additions | 2,300,000 | 170,000 | 2,470,000 | |
| Total Additions | 9,167,239 | 680,000 | 9,847,239 | |
| Retirements - October 1, 2024 thru September 30, 2025 | | | | |
| Distribution / General Plant | (250,000) | (85,000) | (335,000) | |
| Retirements - October 1, 2025 thru March 31, 2026 | | | | |
| Distribution / General Plant | (125,000) | (42,500) | (167,500) | |
| Total Retirements | (375,000) | (127,500) | (502,500) | |
| Electric Depreciable Plant at September 30, 2025 | 43,191,790 | 1,787,439 | 44,979,229 | |
| x Book Basis Average Composite Depreciation Rate | 2.488% | 15.866% | 3.020% | |
| Calculated Accruals to Depreciation Expense | | | | |
| For The Twelve Months Ended September 30, 2025 | 1,074,600 | 283,600 | 1,358,200 | |
| Less: Depreciation Expense as of September 30, 2024 | 788,560 | 308,390 | 1,096,900 | |
| Increase In Depreciation Expense | 286,040 | (24,790) | | $ 261,300 |
| Change No. (12a) Rounded | | | | $ 261,300 |

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

| Electric- 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 - E- 360000 - LAND-EASEMENTS | 3,306.55 | - | 3,306.55 | 50 | 2.00% | - | 66.13 | 2.00% | 0.167% |
| PK - E- 360100 - LAND & LR FEE | 1,087,646.00 | - | 1,087,646.00 | - | - | - | - | | |
| PK - E- 361000 - STRUCTURES & IMPRO | (2,831.71) | - | (2,831.71) | 50 | 2.00% | - | (56.63) | 2.00% | 0.167% |
| PK - E- 362000 - STATION EQUIPMENT | 1,272,590.58 | - | 1,272,590.58 | 40 | 2.50% | (1.00) | 31,813.76 | 2.50% | 0.208% |
| PK - E- 364000 - POLES, TOWRS & FIX | 13,037,685.69 | - | 13,037,685.69 | 45 | 2.22% | 16,348.00 | 305,784.62 | 2.35% | 0.195% |
| PK - E- 365500 - OH CONDUCTOR & DEV | 7,065,538.92 | - | 7,065,538.92 | 50 | 2.00% | 12,783.00 | 154,093.78 | 2.18% | 0.182% |
| PK - E- 365600 - O/H CONDUCT CAPACI | 24,636.44 | - | 24,636.44 | 30 | 3.33% | 89.00 | 909.39 | 3.69% | 0.308% |
| PK - E- 366000 - UG CONDUIT | 299,714.13 | - | 299,714.13 | 65 | 1.54% | 143.00 | 4,758.60 | 1.59% | 0.132% |
| PK - E- 367000 - UG CONDUCT & DEVI | 656,995.88 | - | 656,995.88 | 50 | 2.00% | 147.00 | 13,286.92 | 2.02% | 0.169% |
| PK - E- 368100 - LINE TRANSFORM OH | 1,174,971.35 | - | 1,174,971.35 | 35 | 2.86% | 2,144.00 | 35,748.18 | 3.04% | 0.254% |
| PK - E- 368200 - L TRANS OH INSTALL | 1,886,358.91 | - | 1,886,358.91 | 35 | 2.86% | 2,348.00 | 56,297.86 | 2.98% | 0.249% |
| PK - E- 368300 - LINE TRANSFORM -UG | 937,757.21 | - | 937,757.21 | 35 | 2.86% | (1,474.00) | 25,345.86 | 2.70% | 0.225% |
| PK - E- 368400 - L TRANS UG INSTALL | 620,164.05 | - | 620,164.05 | 35 | 2.86% | 1,507.00 | 19,243.69 | 3.10% | 0.259% |
| PK - E- 369100 - SERVICES-OVERHEAD | 1,362,876.93 | - | 1,362,876.93 | 55 | 1.82% | 3,581.00 | 28,385.36 | 2.08% | 0.174% |
| PK - E- 369200 - SERVICES-UG | 1,081,254.76 | - | 1,081,254.76 | 55 | 1.82% | 316.00 | 19,994.84 | 1.85% | 0.154% |
| PK - E- 370100 - METERS | 22,870.08 | - | 22,870.08 | 20 | 5.00% | (201.00) | 942.50 | 4.12% | 0.343% |
| PK - E- 370110 - METERS SS | 210,067.75 | - | 210,067.75 | 20 | 5.00% | (3,414.00) | 7,089.39 | 3.37% | 0.281% |
| PK - E- 370200 - METER INSTALLS | 380,445.60 | - | 380,445.60 | 20 | 5.00% | - | 19,022.28 | 5.00% | 0.417% |
| PK - E- 370210 - METER INSTALLS-SS | 343,547.22 | - | 343,547.22 | 20 | 5.00% | - | 17,177.36 | 5.00% | 0.417% |
| PK - E- 373100 - STREET LIGHTS -OH | 735,150.21 | - | 735,150.21 | 35 | 2.86% | 832.00 | 21,857.30 | 2.97% | 0.248% |
| **Electric- Distribution Total** | **32,200,746.55** | **-** | **32,200,746.55** | | | **35,148.00** | **761,761.19** | | |
| **Depreciable Electric- Distribution Total** | **31,113,100.55** | **-** | **31,113,100.55** | | | **35,148.00** | **761,761.19** | **2.448%** | **0.204%** |
| **Electric- General Plant Total** | | | | | | | | | |
| PK - E- 390000 - STRUCTURES & IMPRO | 2,339,398.77 | - | 2,339,398.77 | 45 | 2.22% | - | 51,934.65 | 2.22% | 0.185% |
| PK - E- 394 & 399 TOOLS & EXCESS RESERVE | 197,052.00 | - | 197,052.00 | 5 | 20.00% | - | 39,410.40 | 20.00% | 1.667% |
| **Electric- General Plant Total** | **2,536,450.77** | **-** | **2,536,450.77** | | | **-** | **91,345.05** | | |
| **Depreciable Electric- General Plant Total** | **2,536,450.77** | **-** | **2,536,450.77** | | | **-** | **91,345.05** | **3.601%** | **0.300%** |
| Electric-Other Intangible Plant | | | | | | | | | |
| PK - E- 301000 - ORGANIZATION | - | - | - | - | - | | - | | |
| **Electric-Other Intangible Plant Total** | **-** | **-** | **-** | | | **-** | **-** | | |
| **Depreciable Elec.-Other Intang. Plant** | **-** | **-** | **-** | | | **-** | **-** | | |
| **Amortization of Unallocated Reserve** | | | | | | (16,000.00) | (16,000.00) | | |
| **Total Electric** | **34,737,197.32** | **-** | **34,737,197.32** | | | **19,148.00** | **837,106.24** | | |
| **Total Depreciable Electric** | **33,649,551.32** | **-** | **33,649,551.32** | | | **19,148.00** | **837,106.24** | **2.488%** | **0.207%** |

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

| Account | Common General Plant | June 30, 2020 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% |
| 398901 | Miscellaneous Equipment | 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 & Power Company
Statement in Support of Change No. (12b)
To Depreciation Expense
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 12
Page 4 of 4

| Electric Plant | Proposed Annual Net Salvage | Current Net Salvage Allowed | Net Change In Expense |
|---|---|---|---|
| 361000 STRUCTURES AND IMPROVEMENTS | - | $ - | $ - |
| 362000 STATION EQUIPMENT | (1) | (1) | - |
| 364000 POLES, TOWERS AND FIXTURES | 16,348 | 16,348 | - |
| 365000 OH CONDUCTORS & DEVICES | 12,783 | 12,783 | - |
| 365100 CAPACITORS | 89 | 89 | - |
| 366000 UG CONDUIT | 143 | 143 | - |
| 367000 UG CONDUCTORS | 147 | 147 | - |
| 368100 LINE TRANSFORMER OH PURCHASE | 2,144 | 2,144 | - |
| 368200 LINE TRANSFORMER OH INSTALLS | 2,348 | 2,348 | - |
| 368300 LINE TRANSFORMER UG PURCHASE | (1,474) | (1,474) | - |
| 368400 LINE TRANSFORMER UG INSTALLS | 1,507 | 1,507 | - |
| 369100 OH SERVICES | 3,581 | 3,581 | - |
| 369200 UG SERVICES | 316 | 316 | - |
| 370100 ELECTRIC METERS PURCHASE 2003 & < | (201) | (201) | - |
| 370110 ELECTRIC METERS PURCHASE 2004 & > | (3,414) | (3,414) | - |
| 370200 ELECTRIC METERS INSTALLS 2003 & < | - | - | - |
| 370210 ELECTRIC METERS INSTALLS 2004 & > | - | - | - |
| 373100 STREETLIGHTS OH | 832 | 832 | - |
| **TOTAL ELECTRIC** | $ 35,148 | $ 35,148 | $ - |
| 26 Year Amortization of Reserve Excess - Case R-2008-2046518 through March 2035 | (16,000) | (16,000) | - |
| Annual Amount | $ 19,148 | $ 19,148 | $ - |
| Rounded | | | $ - |

Pike County Light & Power Company
Statement in Support of Change No. (13a)
To Taxes other than Income
For the Twelve Months Ended September 30, 2025

Exhibit E-4
Schedule 13
Page 1 of 2

| Changes in Taxes Other | Actual 12 ms ending 9/30/2024 | Future Year 12 ms ending 9/30/2025 | Change |
|---|---|---|---|
| | (1) | (2) | (3) |
| Payroll Taxes - Base Payroll | $ 117,437 | 36,881 | $ (80,556) |
| Pa. Gross Receipts Tax (5.9%) | 419,918 | 957,977 | 538,059 |
| Pa. Realty | 19,608 | 18,338 | (1,270) |
| Total | $ 556,962 | $ 1,013,196 | $ 456,234 |
| Rounded | $ 557,000 | $ 1,013,200 | $ 456,200 |

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 Test Year Payroll | $ | 396,977 |
| Wage Increase and Annualization | | 25,127 |
| Salary and wages for additional employees | | 60,000 |
| Total increase in wages | $ | 482,104 |
| FICA / Medicare Rate | | 7.65% |
| Total Payroll Taxes | $ | 36,881 |
| Rounded Total | $ | 36,900 |

Pike County Light And Power Company
Calculation of Electric 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 | 2,519,500 | - | $ 2,519,500 | $ (840,900) | $ 1,678,600 | $ 1,758,800 | $ 3,437,400 |
| Less Interest Expense (incl amort of debt exp) | 1,035,742 | 1,417,640 | 2,453,383 | 360,935 | 2,814,318 | - | 2,814,318 |
| Other Income & Deductions (incl Donations) | 19,798 | (19,798) | - | - | | | |
| Book Income Before FIT | 1,503,556 | (1,437,439) | 66,117 | (1,201,835) | (1,135,718) | 1,758,800 | 623,082 |
| Section I- Permanent Items: | | | | | | | |
| Add: Negative Provision for Uncollectibles | (82,022) | 82,022 | - | | - | | - |
| Total | (82,022) | 82,022 | - | - | - | - | - |
| Pretax Income | 1,585,578 | (1,519,461) | 66,117 | (1,201,835) | (1,135,718) | 1,758,800 | 623,082 |
| Section II - Normalized Items: | | | | | | | |
| Add: Additional Taxable Income and Unallowable Deductions: | | | | | | | |
| Book Depreciation | 1,096,900 | - | 1,096,900 | 261,300 | 1,358,200 | - | 1,358,200 |
| Amortization of Rate Case Expenditures | - | - | - | 53,100 | 53,100 | - | 53,100 |
| Amortization of Deferred Storm Costs | 45,528 | - | 45,528 | 29,700 | 75,228 | - | 75,228 |
| Deferred FIT Customer Credits (Negative Rev) | - | - | - | - | - | - | - |
| Amort. of Deferred DSP Legal Fees (Expired) | - | | - | - | - | - | - |
| Amort. of Deferred OPEB Exp. (Expiring) | - | - | - | - | - | - | - |
| Increase in Deferred Purchased Power Costs | (1,247,536) | - | (1,247,536) | 1,247,536 | - | - | - |
| Total | (105,108) | - | (105,108) | 1,591,636 | 1,486,528 | - | 1,486,528 |
| Deduct: Non-Taxable Income and Allowable Deductions | | | | | | | |
| Tax Depreciation | 1,560,756 | - | 1,560,756 | - | 1,560,756 | - | 1,560,756 |
| Deferred Rate Case Expenditures | - | - | - | 212,500 | 212,500 | - | 212,500 |
| Deferred Storm Costs | - | - | - | - | - | - | - |
| Amort.- Deferred FIT Cust. Cr (Negative Rev.) | - | - | - | - | - | | - |
| Deferred DSP Legal Fees (Expired) | - | - | - | - | - | - | - |
| Deferred OPEB Expenditures (Expiring) | - | - | - | - | - | - | - |
| Recovery of Prior Def. Purchased Power Costs | (136,101) | - | (136,101) | 136,101 | - | - | - |
| Total | 1,424,654 | - | 1,424,654 | 348,601 | 1,773,256 | - | 1,773,256 |
| Federal NOL | - | - | - | | - | | - |
| Taxable Income | 55,816 | (1,519,461) | (1,463,645) | 41,199 | (1,422,446) | 1,758,800 | 336,354 |
| State Tax Adjustments | - | - | - | - | - | - | - |
| Adjusted Taxable Income | 55,816 | (1,519,461) | (1,463,645) | 41,199 | (1,422,446) | 1,758,800 | 336,354 |
| x State Income Tax @ 7.99% | 7.99% | 7.99% | 7.99% | 7.99% | 7.99% | 7.99% | 7.99% |
| Current Tax Provision | 4,460 | (121,405) | (116,945) | 3,292 | (113,653) | 140,500 | 26,847 |
| Deferred Income Tax Dr.- Account 410 | 113,830 | - | 113,830 | 27,853 | 141,683 | - | 141,683 |
| Deferred Income Tax Cr.- Account 411 | 8,398 | - | 8,398 | (127,172) | (118,774) | - | (118,774) |
| | 126,688 | (121,405) | 5,283 | (96,027) | (90,744) | 140,500 | 49,756 |
| Rounded | $ 126,700 | $ (121,400) | $ 5,300 | $ (96,000) | $ (90,700) | $ 140,500 | $ 49,800 |

Pike County Light And Power Company
Calculation of Electric 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) |
|---|---|---|---|---|---|---|---|
| State Taxable Income (E-4, Sched 14, Pg 1) | $ 55,816 | $ (1,519,461) | $ (1,463,645) | $ 41,199 | $ (1,422,446) | $ 1,758,800 | $ 336,354 |
| Less: State Income Tax | (126,688) | 121,405 | (5,283) | 96,027 | 90,744 | (140,500) | (49,756) |
| Federal Tax Adjustments | - | - | - | - | - | - | - |
| Adjusted Taxable Income | (70,872) | (1,398,056) | (1,468,928) | 137,226 | (1,331,702) | 1,618,300 | 286,598 |
| * Federal Income Tax Rate | 21% | 21% | 21% | 21% | 21% | 21% | 21% |
| Current Federal Income Tax | $ (14,883) | $ (293,592) | $ (308,475) | $ 28,817 | $ (279,657) | $ 339,800 | $ 60,143 |
| Deferred Federal Income Tax Applicable To: | | | | | | | |
| Book Depreciation | (230,349) | - | (230,349) | (54,873) | (285,222) | - | (285,222) |
| Amortization of Rate Case Expenditures | - | - | - | (11,151) | (11,151) | - | (11,151) |
| Amortization of Deferred Storm Costs | (9,561) | - | (9,561) | (6,237) | (15,798) | - | (15,798) |
| Deferred FIT Customer Credits (Negative Rev) | - | - | - | - | - | - | - |
| Amort. of Deferred DSP Legal Fees (Expired) | - | - | - | - | - | - | - |
| Amort. of Deferred OPEB Exp. (Expiring) | - | - | - | - | - | - | - |
| Increase in Deferred Purchased Gas Costs | 261,983 | - | 261,983 | (261,983) | - | - | - |
| Tax Depreciation | 327,759 | - | 327,759 | - | 327,759 | - | 327,759 |
| Deferred Rate Case Expenditures | - | - | - | 44,625 | 44,625 | - | 44,625 |
| Deferred Storm Costs | - | - | - | - | - | - | - |
| Amort.- Deferred FIT Cust. Cr (Negative Rev.) | - | - | - | - | - | - | - |
| Deferred DSP Legal Fees (Expired) | - | - | - | - | - | - | - |
| Deferred OPEB Expenditures (Expiring) | - | - | - | - | - | - | - |
| Recovery of Prior Def. Purchased Power Costs | (28,581) | - | (28,581) | 28,581 | - | - | - |
| Total | 321,250 | - | 321,250 | (261,037) | 60,213 | - | 60,213 |
| Summary of Federal Income Taxes: | | | | | | | |
| Current Federal Income Tax | (14,883) | (293,592) | (308,475) | 28,817 | (279,657) | 339,800 | 60,143 |
| Deferred Federal Income Tax | 321,250 | - | 321,250 | (261,037) | 60,213 | - | 60,213 |
| Total | $ 306,367 | $ (293,592) | $ 12,775 | $ (232,220) | $ (219,445) | $ 339,800 | $ 120,355 |
| Rounded | $ 306,400 | $ (293,600) | $ 12,800 | $ (232,200) | $ (219,400) | $ 339,800 | $ 120,400 |

Pike County Light And Power Company
Calculation of Electric Income Taxes
Interest Synchronization
For The Twelve Months Ended September 30, 2025

| | Per Books 12 Months Ended 9/30/2024 | Rate Base Adjustments | 12 Months Ended 9/30/2024 (1) | Proposed Rate Change (2) | As Adjusted For Additional Revenue (3) = (1) + (2) |
|---|---|---|---|---|---|
| Rate Base | $ 34,027,500 | | $ 34,027,500 | $ 5,006,039 | $ 39,033,539 |
| Interest Component of Capitalization | 3.04% | 4.17% | 7.21% | 7.21% | 7.21% |
| Interest Expense | 1,035,742 | $ 1,417,640 | $ 2,453,383 | $ 360,935 | $ 2,814,318 |
| Rounded | $ 1,035,700 | $ 1,417,600 | $ 2,453,400 | $ 360,900 | $ 2,814,300 |

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

Exhibit E-5

| Schedule | Title of Schedule | Witness |
|---|---|---|
| (1) | Historic Electric Sales by Service Classification | C. Lenns & M. Lenns |
| (2) | Future Electric Sales by Service Classification | C. Lenns & M. Lenns |
| (3) | Historic Electric Revenue by Service Classification | C. Lenns & M. Lenns |
| (4) | Future Electric Revenue by Service Classification | C. Lenns & M. Lenns |
| (5) | Forecasted Electric Sales Volumes | C. Lenns & M. Lenns |
| (6) | Forecast Electric Sales and Revenues | C. Lenns & M. Lenns |

Exhibit E-5
Schedule 1

**PIKE COUNTY LIGHT AND POWER COMPANY**

**Electric Sales (KWH)**
**For the 12 Months Ended September 30, 2024**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales** | | | | | | | | | | | | | |
| SC1 | 2,309,237 | 2,857,962 | 2,874,712 | 3,618,223 | 2,997,469 | 2,392,882 | 2,506,846 | 2,428,686 | 2,769,982 | 3,947,272 | 3,039,126 | 2,357,831 | 34,100,228 |
| SC2P | 938,245 | 964,215 | 846,335 | 1,017,730 | 872,480 | 804,545 | 924,630 | 1,054,725 | 957,530 | 1,265,460 | 1,141,000 | 1,017,135 | 11,804,030 |
| SC2S | 2,749,576 | 2,745,842 | 2,488,411 | 3,045,524 | 2,663,972 | 2,354,658 | 2,730,697 | 3,006,340 | 2,986,432 | 3,897,467 | 3,287,751 | 2,844,464 | 34,801,134 |
| SC3 | 31,445 | 33,994 | 33,146 | 28,700 | 27,444 | 23,048 | 21,192 | 19,051 | 20,425 | 22,783 | 25,046 | 29,203 | 315,478 |
| SC4 | 14,945 | 16,124 | 15,345 | 13,305 | 12,682 | 10,709 | 9,821 | 8,829 | 9,461 | 10,503 | 11,303 | 13,198 | 146,226 |
| Total | 6,043,447 | 6,618,137 | 6,257,950 | 7,723,483 | 6,574,047 | 5,585,842 | 6,193,186 | 6,517,630 | 6,743,831 | 9,143,485 | 7,504,227 | 6,261,831 | 81,167,096 |

**PIKE COUNTY LIGHT AND POWER COMPANY**

**Electric Sales (KWH)**
**For the 12 Months Ended September 30, 2025**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales** | | | | | | | | | | | | | |
| SC1 | 2,401,606 | 2,972,280 | 2,989,700 | 3,762,952 | 3,117,368 | 2,488,597 | 2,607,120 | 2,525,833 | 2,880,781 | 4,105,163 | 3,160,691 | 2,452,144 | 35,464,237 |
| SC2P | 976,853 | 1,003,892 | 881,161 | 1,059,609 | 908,382 | 837,652 | 962,678 | 1,098,126 | 996,932 | 1,317,533 | 1,187,951 | 1,058,989 | 12,289,759 |
| SC2S | 2,859,559 | 2,855,676 | 2,587,947 | 3,167,345 | 2,770,531 | 2,448,844 | 2,839,925 | 3,126,594 | 3,105,889 | 4,053,366 | 3,419,261 | 2,958,243 | 36,193,179 |
| SC3 | 32,702 | 35,354 | 34,472 | 29,848 | 28,542 | 23,970 | 22,040 | 19,813 | 21,242 | 23,694 | 26,048 | 30,371 | 328,097 |
| SC4 | 15,542 | 16,768 | 15,959 | 13,838 | 13,189 | 11,137 | 10,214 | 9,182 | 9,840 | 10,923 | 11,755 | 13,726 | 152,075 |
| Total | 6,286,263 | 6,883,971 | 6,509,240 | 8,033,592 | 6,838,012 | 5,810,200 | 6,441,976 | 6,779,548 | 7,014,684 | 9,510,679 | 7,805,707 | 6,513,473 | 84,427,347 |

Exhibit E-5
Schedule 3

**PIKE COUNTY LIGHT AND POWER COMPANY**

**Electric Delivery Revenues ($)**
**For the 12 Months Ended September 30, 2024**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Delivery Revenue** | | | | | | | | | | | | | |
| SC1 | $ 251,877 | $ 302,823 | $ 304,421 | $ 373,351 | $ 315,822 | $ 259,774 | $ 270,378 | $ 263,112 | $ 294,806 | $ 403,953 | $ 319,782 | $ 272,010 | $ 3,632,108 |
| SC2P | 50,090 | 41,901 | 36,439 | 40,685 | 37,914 | 38,154 | 41,462 | 49,030 | 47,990 | 52,547 | 52,218 | 52,878 | 541,308 |
| SC2S | 244,654 | 241,089 | 220,714 | 257,632 | 231,640 | 211,133 | 236,954 | 263,614 | 265,957 | 329,295 | 285,401 | 252,819 | 3,040,902 |
| SC3 | 9,317 | 9,317 | 9,336 | 9,378 | 9,381 | 9,393 | 9,424 | 9,424 | 9,424 | 9,428 | 9,403 | 9,404 | 112,628 |
| SC4 | 4,357 | 4,088 | 4,117 | 4,091 | 4,089 | 4,121 | 4,121 | 4,121 | 4,121 | 4,106 | 4,107 | 4,089 | 49,527 |
| Total | $ 560,295 | $ 599,218 | $ 575,027 | $ 685,137 | $ 598,845 | $ 522,576 | $ 562,339 | $ 589,301 | $ 622,297 | $ 799,328 | $ 670,910 | $ 591,200 | $ 7,376,474 |

**PIKE COUNTY LIGHT AND POWER COMPANY**

**Electric Delivery Revenues ($)**
**For the 12 Months Ended September 30, 2024**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Delivery Revenue** | | | | | | | | | | | | | |
| SC1 | $ 261,952 | $ 314,936 | $ 316,597 | $ 388,285 | $ 328,455 | $ 270,165 | $ 281,193 | $ 273,637 | $ 306,598 | $ 420,111 | $ 332,573 | $ 266,886 | $ 3,761,388 |
| SC2P | 52,099 | 43,574 | 37,887 | 42,308 | 39,422 | 39,672 | 43,116 | 50,996 | 49,913 | 54,657 | 54,315 | 55,002 | 562,960 |
| SC2S | 254,440 | 250,733 | 229,543 | 267,937 | 240,905 | 219,579 | 246,432 | 274,158 | 276,595 | 342,467 | 296,817 | 262,931 | 3,162,538 |
| SC3 | 9,690 | 9,690 | 9,710 | 9,753 | 9,756 | 9,768 | 9,801 | 9,801 | 9,801 | 9,805 | 9,779 | 9,781 | 117,133 |
| SC4 | 4,531 | 4,251 | 4,281 | 4,254 | 4,253 | 4,286 | 4,286 | 4,286 | 4,286 | 4,270 | 4,271 | 4,253 | 51,509 |
| Total | $ 582,712 | $ 623,183 | $ 598,018 | $ 712,538 | $ 622,791 | $ 543,471 | $ 584,829 | $ 612,877 | $ 647,192 | $ 831,310 | $ 697,755 | $ 598,852 | $ 7,655,528 |

**PIKE COUNTY LIGHT & POWER COMPANY**
**Electric Sales (KWHR)**
**For the 12 Months Ended September 30, 2024**

| Column No. | | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|
| **Line No.** | **Description** | **SC 1 Residential** | **SC 2 Primary Commercial** | **SC 2 Secondary Commercial** | **SC3 Municipal Street Lighting** | **SC4 C&I Private Overhead Lighting** | **Total Billed** |
| 1 | Actual billed sales volumes<br>12 months ended September 30, 2024 | 34,100,228 | 11,804,030 | 34,801,134 | 315,478 | 146,226 | 81,167,096 |
| 2 | Sales Growth September 2024 vs. September 2025 | 1,364,009 | 485,729 | 1,392,045 | 12,619 | 5,849 | 3,260,251 |
| 3 | **Forecasted Delivery Volumes**<br>**12 months ended September 30, 2025** | 35,464,237 | 12,289,759 | 36,193,179 | 328,097 | 152,075 | 84,427,347 |
| | **Rounded** | **35,464,200** | **12,289,800** | **36,193,200** | **328,100** | **152,100** | **84,427,400** |
| | **Percentage Change from Test Year** | **4.0%** | **4.1%** | **4.0%** | **4.0%** | **4.0%** | **4.0%** |

EXHIBIT E-5
Schedule 6

**PIKE COUNTY LIGHT & POWER COMPANY**
**Forecast Electtric Sales Revenue**
**For the Twelve Months Ending September 30, 2025**

| Column No. | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Service Classification | | **Electric Customers** | **Electric Delivery Volumes kWHR** | **Sum of Monthly Demand KW** | **Base Revenue (Customer Charge) ($000)** | **Delivery Revenue ($000)** | **DSIC Electric Revenue ($000)** | **Demand Revenues ($000)** | **Market Price of Energy ($000)** | **ECR / Surcharg e ($000)** | **SBC Surcharge ($000)** | **Total Sales Revenue ($000)** | **GRT Recoveries ($000)** | **Total Sales Revenue excl.GRT ($000)** |
| | Billed Delivery | | | | | | | | | | | | | | |
| 1 | SC 1 - Residential | POLR | 3,736 | 30,066,894 | - | - | 3,139,440 | | - | 3,485,980 | - | - | **$ 6,625,420** | $ 390,900 | **$ 6,234,520** |
| | | ESCO | 740 | 5,397,343 | - | - | 621,948 | | - | - | - | - | **621,948** | 36,700 | **585,248** |
| | Total Reisdential | | 4,476 | 35,464,237 | - | - | 3,761,388 | - | - | 3,485,980 | - | - | **7,247,368** | 427,600 | **6,819,768** |
| 2 | SC 2 - Primary | POLR | 9 | 12,289,759 | - | - | 562,960 | | - | 1,803,041 | - | - | **2,366,001** | 139,600 | **2,226,401** |
| | | ESCO | - | - | - | - | - | - | - | - | - | - | **-** | - | **-** |
| | Total SC2 Primary | | 9 | 12,289,759 | - | - | 562,960 | - | - | 1,803,041 | - | - | **2,366,001** | 139,600 | **2,226,401** |
| 3 | SC 2 - Sceondary | POLR | 753 | 28,934,402 | - | - | 2,444,539 | | - | 3,116,603 | - | - | **5,561,141** | 328,100 | **5,233,041** |
| | | ESCO | 221 | 7,258,777 | - | - | 718,000 | | - | - | - | - | **718,000** | 42,400 | **675,600** |
| | Total SC2 Secondary | | 975 | 36,193,179 | - | - | 3,162,538 | - | - | 3,116,603 | - | - | **6,279,141** | 370,500 | **5,908,641** |
| 4 | SC 3 - Municipal Lighting | POLR | 12 | 328,097 | | - | 117,133 | | - | 37,658 | - | - | **154,791** | 9,100 | **145,691** |
| | | ESCO | - | - | | - | - | | - | - | - | - | **-** | - | **-** |
| | Total SC3 Muncipal Lighting | | 12 | 328,097 | - | - | 117,133 | - | - | 37,658 | - | - | **154,791** | 9,100 | **145,691** |
| 5 | SC 4 Private Lighting | POLR | 75 | 148,088 | | - | 49,420 | | - | 12,928 | - | - | **62,349** | 3,700 | **58,649** |
| | | ESCO | 3 | 3,986 | | - | 2,088 | | - | - | - | - | **2,088** | 100 | **1,988** |
| | Total SC4 Privatel Lighting | | 78 | 152,075 | - | - | 51,509 | - | - | 12,928 | - | - | **64,437** | 3,800 | **60,637** |
| | Total Billed Delivery | | 5,550 | 84,427,347 | - | - | 7,655,528 | - | - | 8,456,210 | - | - | **$ 16,111,738** | **$ 950,600** | **$ 15,161,138** |

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

## Verification of Customer Notice

Pike County Light & Power Company has provided the following notice of its electric base rate increase:

1. Notices to customers of the proposed increases was mailed to all Pike County Light & Power Electric customers on January 14, 2025;
2. Notice of a Rate Increase has been posted in the Company's offices at 105 Schneider Lane, Milford, PA 18337 on January 14, 2025. This notice is the same notice as the notice mailed to customers;
3. Notice of a Rate Increase for Pike County Light & Power Electric 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 January 14, 2025; and
4. Notice of a Rate Increase that was posted on the Company's website www.pclpeg.com on January 14, 2025. 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: January 14, 2025

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

NOTICE OF PROPOSED ELECTRIC RATE CHANGES

01/14/2025

To Our Electric Customer

Pike County Light and Power Company, Inc. is filing a request with the Pennsylvania Public Utility Commission (PUC) to increase your Electric 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 $1,874,600 per year, if the company's entire request is approved, customer bills would increase as follows:

- Residential customers using 674 kWh's per month would Increase from $134.29 to $149.81 per month or by 11.6% including estimated energy charges.
- SC2 Primary Customers using 105,514 kWh's per month would Increase from $13,663.88 to $14,444.55 per month or by 5.7% including estimated energy charges and sales tax .
- SC2 Secondary Demand Customers using 3,308 kWh's per month would Increase from $597.02 per month to $642.40 per month or by 7.6% including estimated energy charges and sales tax.
- SC2 Secondary Non-Demand Customers using 532 kWh's per month would Increase from $123.03 per month to $134.49 per month or by 9.3% including estimated energy charges and sales tax.
- Municipal Street Lighting customer bills would increase on average from $1,011.41 per month to $1,209.89 per month or by 19.6% including estimated energy charges
- Private Lighting customer bills would increase on average from $37.31 to $44.20 per month or by 18.5% including estimated energy charges and sales tax.

To find out your customer class or how the requested increase may affect your electric bill, contact Pike County Light & Power Company at (855) 855-2050. The rates requested by the company may be found in TARIFF SUPPLEMENT NO. 105 TO TARIFF-ELECTRIC PA PUC NO. 8. 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:

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

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 March 15, 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.
330 West William Street
Corning, NY 14830

PUBLIC NOTICE ELECTRIC RATES

Pike County Light and Power Company, Inc. is filing a request with the Pennsylvania Public Utility Commission (PUC) to increase your electric rates as of October 1, 2025. The Company has requested an overall rate increase of $1,874,600 per year. If the company's entire request is approved, the total customer bill would increase as follows:

- Residential customers using 674 kWh's per month would Increase from $134.29 to $149.81 per month or by 11.6% including estimated energy charges.
- SC2 Primary Customers using 105,514 kWh's per month would Increase from $13,663.88 to $14,444.55 per month or by 5.7% including estimated energy charges and sales tax .
- SC2 Secondary Demand Customers using 3,308 kWh's per month would Increase from $597.02 per month to $642.40 per month or by 7.6% including estimated energy charges and sales tax.
- SC2 Secondary Non-Demand Customers using 532 kWh's per month would Increase from $123.03 per month to $134.49 per month or by 9.3% including estimated energy charges and sales tax.
- Municipal Street Lighting customer bills would increase on average from $1,011.41 per month to $1,209.89 per month or by 19.6% including estimated energy charges
- Private Lighting customer bills would increase on average from $37.31 to $44.20 per month or by 18.5% including estimated energy charges and sales tax.

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-2024-3052359 |
| | : | |
| Pike County Light & Power Company (electric) | : | |

**Pike County Light and Power Company (Electric)**

**Statement No. 3**

**Direct Testimony of**

**Steven Grandinali**

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

A. My name is Steven L. Grandinali and my business address is One Hundred Avenue K, Matamoras, Pa 18336.

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

A. I am a consultant employed by Pike County Light & Power Company ("Pike" or the "Company").

**Q. Please provide your educational background and professional experience.**

A. I have a Bachelor's of Engineering in Electrical Engineering from Stevens Institute of Technology and a Master's of Business Administration in Organizational Behavior from Iona University. I was employed for 28 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. In 2016, I was employed by Pike County Light & Power Company ("Pike" or the "Company") as the Company's General Manager until retiring in 2021. In that position I was responsible for all operations at Pike.

Since 2021, I have provided services to Pike as a consultant, on an as-needed basis, in areas including operations, engineering, regulatory report preparation and other related functions.

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

A. Yes, in 2019 I provided testimony in both Pike's electric and gas LTTIP filings. Also, in 2020-2021, I provided testimony in Pike's electric and gas rate cases.

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

A. I will provide an overview of Pike's electric system that serves the five municipalities in Pike County, which include Matamoras Borough, Westfall Township, Milford Borough, Milford Township and Dingmans Township, Pennsylvania, discuss Pike's electric system improvement projects as presented in the Company's Distribution Electric Long Term Infrastructure Improvement Plan ("LTIIP") that was submitted to the PAPUC on October 5, 2020 at Docket No. P-2020-3022285, electric metering equipment, vegetation management program requirements, and additional staffing needs.

**Q. Please provide an overview of Pike's electric system that serves the territory in Pennsylvania.**

A. Pike serves approximately 5,350 electric customers of which 1,050 are commercial, 4,210 are residential and 90 are lighting. Pike territory is served primarily from two 34.5 kV feeders that originate from Orange and Rockland Utilities in New York State. The Borough of Matamoras and a small commercial area of Westfall are served by two 13.2 kV feeders from the Matamoras Substation with backup circuit tie capability to a 13.2 kV distribution circuit from Orange and Rockland Utilities. The substation is normally fed by a 34.5 kV circuit "A" with a backup service being provided by a second 34.5 kV circuit "B" through an automatic transfer switch located at the substation. The western portion of the Pike service territory of Milford Borough and Township, and Westfall and Dingmans Township are supplied by a long radial feed from the 34.5 kV circuit "B". In the event of a power outage on circuit "B", power will be restored with switching as long as the outage location is up stream of the Circuit "A" tie point. If the outage is down stream from the Circuit A tie point, approximately 2,600 customers could be without power until repairs are completed. In addition, due to the geography of the area, side roads off of State Route 209 from Westfall to Dingman Township are supplied with radial single or three phase laterals via step down transformers or directly from the 34.5 kV line to the last customers.

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

A. In 2020, the Company submitted a Long-Term Infrastructure Improvement Plan. Included in the plan is funding for recurring pole inspections and defective pole replacements along with six system improvement projects. The details of the Company's capital program are described in the following sections:

1. **The recurring Annual Pole Inspection and Replacement Program:** The Company has focused much of its reliability and system improvement efforts on defective pole replacements. Originally planned as a 12-year cycle, the Company accelerated pole inspections and defective pole replacements in 2017 and 2018, resulting in the Company replacing over one hundred (100) poles along with the pole top apertures. In 2019, the company inspected over 1,000 poles resulting in over 60 poles replaced in 2020. In 2020, pole inspections lagged due to Covid

restrictions; however, from 2021 through 2024, the Company continued with its accelerated pole inspection program resulting in over 150 additional defective poles being replaced. The emphasis on replacement of defective poles has been to focus on the "main-line" of the two 34.5 kV circuits from the Delaware River into Milford Borough and Township and associated laterals. The second stage of priority is to replace defective poles with new equipment installed, such as transformers, regulators and reclosers or in areas where system improvement work such as voltage conversions are being undertaken. By the end of 2024 Pike had inspected virtually all poles in its service territory and replaced virtually all defective poles.

2. **The following four projects are inter-related and will be constructed in phases to continue to create the second 34.5 kV electric supply to Milford Borough. These projects are effectively completed:**

**Capital-Reliability Project, Old Milford Road to Route 209:** This project is a reliability improvement project initiated under the prior ownership (i.e., O & R) to replace, convert and extend approximately 6,000 feet of electric distribution. It was undertaken to extend the 35.4 kV and 13.2 kV lines, connecting two previously completed phases. This project has improved system reliability by creating a distribution loop into Milford Borough. This loop would also provide the initial construction or link for a second 34.5 kV from the current source or from an alternate supply.

**Installation of 1500 feet of Civil portion for Second 34.5 kV supply along Route 209:** This project is on hold pending the Milford sewer project.

**Capital-Reliability Project, Old Milford Road to Cummins Hill Road:** This project replaced approximately 4,000 feet of aging 34.5 kV distribution circuits. Consistent with the Company's strategy to improve the reliability of the 34.5 kV system the project included construction of a 13.2 kV underbuild along its entirety.

**ROW Improvement of 116-2-34:** This project, completed in 2024, provides a second 34.5 kV tie between Circuit "A" and Circuit "B" with the tie point being closer to the load, improving reliability of the 34.5 kV distribution system for customers at the end of Circuit "B". The project included construction of a 13.2 kV underbuild which will serve as a future alternate feed for the commercial load along Route 209 that is currently being fed radially by a single 13.2 kV feeder. The Company's plan is to keep any load growth off the 34.5 kV distribution system to minimize its exposure to distribution system faults. The additional 13.2 kV feeder allows for future growth in the area without compromising the reliability of the 34.5 kV system.

3. **13.2 kV Infrastructure and Capacity Improvement along Route 209, Milford:** This project is included in the LTIIP. As the vacant land is developed along Route 209 and Route 6 between Cummins Hill Road and the Milford Borough line, the existing 34.5 kV to 13.2 kV 1500 kVa step-down transformer banks will no longer be able to service the existing or new load during normal and contingency conditions. In keeping with Company's plan to reduce the 34.5 kV system's exposure to distribution system anomalies, the plan is to install two 9-MVA, 34.5 kV to 13.2 kV pad-mounted transformers. The transformers will be placed strategically to provide reliability for new and existing loads along Routes 209 and 6.

4. **Extend 34.5 kV along Route 6 to Route 84:** This project is in the LTIIP. In order to provide reliable service to existing and new business loads along and around the Route 6 and Route 84 exchange, it will be necessary to reconductor and convert the approximately 4,700 feet of existing 2.4 kV to a higher voltage. This project is consistent with the Company's plan for improving reliability by constructing an interconnection to PJM. As with previous projects, a 34.5 kV circuit will be constructed along with a 13.2 kV underbuild. The 34.5 kV circuit will act as an express capable serving the entirety of the Company's load via a future feed from PJM. The 13.2 kV circuit will pick up the distribution loads along Route 6. As with the Route 209/6 corridor, the two proposed 34.5 kV to 13.2 kV pad mounted

transformers in Project No.3 above will be strategically placed to serve the underbuild. This 34.5kv line extension, rebuild and underbuild project commenced in the last quarter 2024 and should be completed in 2025.

**Q. Please describe the Company's existing meter reading system.**

A. The Company has an Itron PC-based handheld meter reading software system called MF-RS that works with the FC300 handheld meter reading devices. The support for the MV-RS system ended on December 31, 2021. The Company had an annual user subscription at a cost of $4,530 prior to the end of support for the MV-RS system. The Company had been using the MV-RS system and the FC300 handhelds since 2017. The Company can no longer purchase batteries for the handheld devices or receive any updates to the MV-RS software. The FC300 systems operate on an outdated Windows version which was a cybersecurity risk to the Company.

**Q. What are the details of the Nighthawk AMI meter reading system?**

A. Nighthawk is an Advanced Metering Infrastructure ("AMI") meter data collection and management solution from Tesco that works with gas ERT meter reading collection. The Company plans to purchase this system to replace the aging MF-RS system. Nighthawk AMI is scalable and can be installed over time because it will be able to read the Company's existing meters that have ERT devices, both for electric and gas. The Nighthawk system is a cloud-based meter reading system that allows for running reports and monitoring meter reading data in real time. Nighthawk has zero infrastructure outside of the electric meter itself. The system uses cell signals which is why no additional hardware is required on poles or towers. The Nighthawk system provides data storage and access in the cloud through the application. Nighthawk provides regular software updates and houses data on servers which meet the ISO 27001 information security standard. AMI allows for remote disconnection and reconnection of electric meters, remote electric demand reset, outage notification and management, and the meters are bi-directional prepared for solar with detailed delivered, received, and net usage. The Nighthawk system has reporting capabilities for outages, detailed usage summaries for customers, and full company usage reporting. The Company will allow customers to opt out of installation of AMI. If customer refuses to have an AMI meter installed, the customer will be charged a monthly fee for manual reading of $41.98 per month for manual meter reads. That amount compensates us for the amount of travel time, average hourly rate of the meter reader, fringe benefits and transportation costs to manually read the customer meter. The full cost of the Nighthawk AMI system which includes replacing all electric meters, the hosted AMI system, AMI setup and configuration, network design and system planning, billing system integration, project management, onsite training and documentation, and the first-year annual fee for the AMI support and maintenance, hosting, licensing, and communications cost is approximately a $1,240,000 capital investment. The Company would complete the AMI project over an 18-month time period.

**Q. Please explain the Vegetation Management program:**

A. The Company’s two 34.5 kV feeds and two main 13.2 kV distribution circuits represent a total overhead primary mileage of approximately 100 miles. The circuits are located within Pike County. Pike maintains this system on a five-year for the 13.2 kV and three year for the 34.5 kV system vegetation maintenance cycles. In addition, the Company implemented a hazardous tree response program that works with Municipalities to identify problem areas, along with off-cycle hot spotting and routine patrols. The hot spotting and hazardous tree removal initiatives are above the scope of the normal maintenance cycles, but in spite of the additional efforts put forth, they have not eliminated tree related outages. Tree related outages are the largest cause of interruptions in the service territory to both operating voltage systems. For the Twelve Months Ended September 30, 2024, tree caused outages represented 42% of all interruptions; 46% of customers effected and 36% of the Customer minutes of interruption. The cost to complete a full five-year tree trimming cycle is estimated to be approximately one million dollars or $200,000 annually. Each voltage trimming cycle is typically completed within a three-month time frame in each year of the cycle. The annual amounts spent vary based on the work required for each circuit depending on, for example, whether there is blight, significant growth spurts and/or the severity of storms. As shown in Exhibit E-4, Schedule 8, Pike spent $165,555 during the Twelve Months Ended September 30, 2022, $99,414 during the Twelve Months ended September 30, 2023 and $254,273 during the Twelve Months Ended September 30, 2024, or $173,081 on average during those periods. For the Test Year (i.e., the Twelve Months Ended September 30, 2024), the tree trimming costs charged to expense amounted to $146,252. Schedule 8 adjusts the Test Year Level of expense to increase it by $26,800. This will allow the

Company to continue its existing program and to continue off cycle and hazardous tree removals in an effort to reduce potential tree related outages.

**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 E-4, Schedule 4, page 2 of 2, the Company has plans to hire an Assistant General Manager, along with an electric 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"), preparing and filing all gas related Public Utility Commission Report filings and coordinating 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. 35.7 percent of the expense portion of the salary for this position ($50,000) was allocated to Pike's electric operations based on the current gas vs. electric customer split. $20,000 will be allocated to Pike Gas 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. The Systems Planner will perform several tasks including planning, scheduling and implementing maintenance and inspection programs on the electric system facilities, approving operations & maintenance contractor time sheets and invoices, designing and coordinating meter operations technician primary and secondary metering for three phase new business or state line metering projects, and serving as a liaison with electric new business and street light applicants and contractors. The estimated annual wages for this employee would be $100,000. 10.0 percent of the expense portion of the salary for this position ($10,000) was allocated to Pike's electric operation, and the remaining $90,000 will be allocated to capital for Pike Electric. There will be no allocation to Pike Gas for this employee.

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

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

PCLP
PIKE COUNTY LIGHT & POWER

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

**Verification of Customer Notice**

Pike County Light & Power Company has provided the following notice of its electric base rate increase:

1. Notices to customers of the proposed increases was mailed to all Pike County Light & Power Electric customers on January 14, 2025;
2. Notice of a Rate Increase has been posted in the Company's offices at 105 Schneider Lane, Milford, PA 18337 on January 14, 2025. This notice is the same notice as the notice mailed to customers;
3. Notice of a Rate Increase for Pike County Light & Power Electric 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 January 14, 2025; and
4. Notice of a Rate Increase that was posted on the Company's website www.pclpeg.com on January 14, 2025. 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: January 14, 2025

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

NOTICE OF PROPOSED ELECTRIC RATE CHANGES

01/14/2025

To Our Electric Customer

Pike County Light and Power Company, Inc. is filing a request with the Pennsylvania Public Utility Commission (PUC) to increase your Electric 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 $1,874,600 per year, if the company's entire request is approved, customer bills would increase as follows:

- Residential customers using 674 kWh's per month would Increase from $134.29 to $149.81 per month or by 11.6% including estimated energy charges.
- SC2 Primary Customers using 105,514 kWh's per month would Increase from $13,663.88 to $14,444.55 per month or by 5.7% including estimated energy charges and sales tax .
- SC2 Secondary Demand Customers using 3,308 kWh's per month would Increase from $597.02 per month to $642.40 per month or by 7.6% including estimated energy charges and sales tax.
- SC2 Secondary Non-Demand Customers using 532 kWh's per month would Increase from $123.03 per month to $134.49 per month or by 9.3% including estimated energy charges and sales tax.
- Municipal Street Lighting customer bills would increase on average from $1,011.41 per month to $1,209.89 per month or by 19.6% including estimated energy charges
- Private Lighting customer bills would increase on average from $37.31 to $44.20 per month or by 18.5% including estimated energy charges and sales tax.

To find out your customer class or how the requested increase may affect your electric bill, contact Pike County Light & Power Company at (855) 855-2050. The rates requested by the company may be found in TARIFF SUPPLEMENT NO. 105 TO TARIFF-ELECTRIC PA PUC NO. 8. 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:

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

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 March 15, 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.
330 West William Street
Corning, NY 14830

PUBLIC NOTICE ELECTRIC RATES

Pike County Light and Power Company, Inc. is filing a request with the Pennsylvania Public Utility Commission (PUC) to increase your electric rates as of October 1, 2025. The Company has requested an overall rate increase of $1,874,600 per year. If the company's entire request is approved, the total customer bill would increase as follows:

- Residential customers using 674 kWh's per month would Increase from $134.29 to $149.81 per month or by 11.6% including estimated energy charges.
- SC2 Primary Customers using 105,514 kWh's per month would Increase from $13,663.88 to $14,444.55 per month or by 5.7% including estimated energy charges and sales tax .
- SC2 Secondary Demand Customers using 3,308 kWh's per month would Increase from $597.02 per month to $642.40 per month or by 7.6% including estimated energy charges and sales tax.
- SC2 Secondary Non-Demand Customers using 532 kWh's per month would Increase from $123.03 per month to $134.49 per month or by 9.3% including estimated energy charges and sales tax.
- Municipal Street Lighting customer bills would increase on average from $1,011.41 per month to $1,209.89 per month or by 19.6% including estimated energy charges
- Private Lighting customer bills would increase on average from $37.31 to $44.20 per month or by 18.5% including estimated energy charges and sales tax.

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.

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing Docket No. R-2024-3052359

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 5,348 electric customers.

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

**Response:** All SC1, SC2, SC3 and SC4 customers will be impacted by the rate change.

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

**Response:** See Exhibit E-8.

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

**Response:** See Exhibit E-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:** N/A

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

**Response:** N/A

(10) 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 E-6.

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

**Response:** Not applicable.

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

Electric Rate Case Filing Docket No. R-2024-3052359

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 E-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 E-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 E-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:** None.

**<u>Part (c)</u>** 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 E-4 and E-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 E-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 E-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 E-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 E-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 E-1, Schedules 2 and 4 show Pike's electric and gas information separately.

# GENERAL FILING INFORMATION—PIKE ELECTRIC

# SUMMARY OF FILING

1. Provide a summary discussion of the rate change request, including specific reasons for each increase or decrease. Also provide a breakdown which identifies the revenue requirement value of the major items generating the requested rate change.

**Response: Please refer to pages 4-10 of the direct testimony of the Accounting Panel (Statement No. 2).**

2. Identify the proposed witnesses for all statements and schedules of revenues, expenses, taxes, property, valuation and the like.

**Response: See below**

**Statement 1 - Cost of Service / Rate Panel witnesses are Paul M. Normand and Debbie L. Gajewski**

**Statement 2 – Accounting Panel witnesses are Charles Lenns and Matthew Lenns**

**Statement 3 – Steve Grandinali**

3. Provide a single page summary table showing, at present and at proposed rates, together with references to the filing information, the following as claimed for the fully adjusted test year:

Revenues

Operating Expenses

Operating Income

Rate Base

Rate of Return (produced)

**Response: Please refer to Exhibit E-4, Summary.**

4. Whenever a major generating plant is placed in operating service or removed from operating service the utility shall separately indicate the effect of the plant addition or removal from service upon rate base, revenue, expense, tax, income and revenue requirement as it affects the test year.

**Response: N/A – Pike has no generating assets.**

# B. GENERAL DESCRIPTION OF UTILITY OPERATIONS

1. Provide a corporate history including the dates of original incorporation, subsequent mergers and acquisitions. Indicate all counties, cities and other governmental subdivisions to which service is provided, including service areas outside this Commonwealth, and the total number of customers or billed units in the areas served.

**Response: Pike County Light & Power Company was officially incorporated as a subsidiary of Orange County Public Service Company of Port Jervis, NY on May 17, 1910. The Company merged with two local gas companies on October 8, 1913, Pike County Gas Company and Matamoras Gas Company. In 1914, Pike merged with Milford Electric Company, Milford Township Electric Company and Westfall Electric Company. In 1926 the Company merged with Rockland Light and Power Company of New Jersey, and further acquired the Will Rift Light and Power Company in 1927, and by 1929 the Company bought Dingman Township Electric Company. In 1958, the Company merged with Orange and Rockland Electric Company of New York and became Orange and Rockland Utilities, Inc. Orange and Rockland Utilities was acquired by Con Edison in 1998 and continued to operate as a subsidiary of O&R until 2016. In 2016 Orange & Rockland sold the Company to Corning Natural Gas Holding Corporation. On July 6 ,2022, Corning Natural Gas Holding Corporation was acquired by Argo Infrastructure Partners, and the Company's parent name was changed to Corning Energy Corporation. The Company provides electricity to the townships of Westfall, Milford, NE Dingman and the boroughs of Matamoras and Milford. The Company provides natural gas service to the township of Westfall and the borough of Matamoras.**

2. Provide a description of the property of the utility and an explanation of the system's operation, and supply the following, using available projections if actual data is unavailable:

a. A schedule of generating capability showing for the test year, and for the two consecutive 12-month periods prior to the test year, net dependable capacity in KW by unit, plant capacity factor by unit, and total fuel consumption by type and cost for each unit, if available, or for each station, and operation and maintenance expenses by station.

**Response: N/A – Pike has no power generating assets.**

:

b. A schedule showing for the test year and for the 12-month period immediately prior to the test year the scheduled and unscheduled outages—in excess of 48 hours—for each station, the equipment or unit involved, the date the outage occurred, duration of the outage, maintenance expenses incurred for each outage, if available, and amounts reimbursable from suppliers or insurance companies.

**Response: N/A – Pike has no power generating assets.**

c. A schedule for each unit retired during the test year or subsequent to the end of the test year, which shows the unit's KW capacity, hours of operation during the test year, net output generated, cents/KWH of maintenance and fuel expenses, and date of retirement.

**Response: N/A – Pike has no power generating assets.**

d. A schedule showing latest projections of capacity additions and retirements—costs and KW—and reserve capacity at the time of peak for at least 10 years beyond the test year, including the inservice dates—actual or expected—and AFDC cutoff dates—if different from inservice dates—for all new generating units coming on line during or subsequent to the test year, if claimed.

**Response: N/A – Pike has no power generating assets.**

3. Provide an overall system map, including and labeling all generating plants, transmission substations—indicate voltage, transmission system lines—indicate voltage, and all interconnection points with other electric utilities, power pools, and other like systems.

**Response: Maps of the Company's system are available for inspection at its offices at 105 Schneider Lane, Milford, Pa. 18337.**

## A. RATE BASE—UNADJUSTED TO ADJUSTED BASIS

1. Provide a schedule showing the test year rate base and rates of return at original cost less accrued depreciation under present rates and under proposed rates. Claims made on this schedule should be cross-referenced to appropriate supporting schedules.

   **Response: Please refer to Exhibit E-4 and E-3.**

2. If the schedule provided in response to item 1, is based upon a future test year, provide a similar schedule which is based upon actual data for the 12-month period immediately prior to the test year.

   **Response: Please refer to Exhibits E-4 and E-3.**

## B. RATE BASE SUPPORTING SCHEDULES

1. If a claim is made for plant held for future use, supply the following:
   a. A description of the plant or land site and its cost and any accumulated depreciation.

   b. The expected date of use for each item claimed.

c. An explanation as to why it is necessary to acquire each item in advance of date of use.

d. The data when each item was acquired.

e. The date when each item was placed in plant held for future use.

**Response: N/A – Pike does have any future use property.**

2. If a claim is made for construction work in progress, provide a supporting schedule which sets forth separately, revenue-producing and nonrevenue producing amounts, and include, for each category a summary of all work orders, amounts expended at the end of the test year and anticipated in service dates. Indicate if the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion dates and estimated total amounts to be spent on each project.

   **Response: N/A – All CWIP closed to Plant in Service.**

3. If a claim is made for materials and supplies or fuel inventory provide a supporting schedule for each claim showing the latest actual 13 monthly balances and showing in the case of fuel inventory claims, the type of fuel, and location, as in station, and the quantity and price claimed.

   **Response: Please refer to Exhibit E-3, Schedule 4.**

4. If a claim is made for cash working capital provide a supporting schedule setting forth the method and all detailed data utilized to determine the cash working capital requirement. If not provided in the support data provide a lead-lag study of working capital, completed no more than 6 months prior to the rate increase filing.

   **Response: Please refer to Exhibit E-3, Schedule 3 for the Company's Working Capital Summary. The Lead Lag Study based on the Twelve Month Ended September 30, 2024. Workpapers are available in Excel or hard copy upon request.**

5. If a claim is made for compensating bank balances, provide the following information:

   **Response: N/A – The Company is not requesting the inclusion of compensating bank balances.**

6. Explain in detail by statement or exhibit the appropriateness of additional claims or the use of a method not previously mentioned, in the claimed rate base.

   **Response: The Company included the average prepaid balance for property taxes and the PaPUC Assessment, in Rate Base (see Exhibit E-3, Schedule 5). The Company also included the unamortized balance of Regulatory Assets for Deferred Storm and Rate Case costs in Rate Base (see Exhibit G-3, Schedule 6.**

## C. OPERATING INCOME STATEMENT

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing – Docket No. R-2024-3052359

Responses to Data Requests Under Section 53.53

1. Prepare a Statement of Income including:

a. The book, or budgeted, statement for the test year.

**Response: Please refer to Exhibit E-4, Summary.**

b. Adjustments to annualize and normalize under present rates, including an elimination of the effects on income of the energy cost rate and state tax adjustment surcharge.

**Response: Please refer to Exhibit E-4, Schedule 1.**

c. The income statement under present rates after adjustment.

**Response: Please refer to Exhibit E-4, Summary.**

d. The adjustment for the revenue requested.

**Response: Please refer to Exhibit E-4, Summary.**

e. The income statement under requested rates after adjustment.

**Response: Please refer to Exhibit E-4, Summary.**

## D. INCOME STATEMENT SUPPORTING SCHEDULES

1. Provide a schedule showing all revenues and expenses for the test year and for the 12-month period immediately prior to the test year.

   **Response: Please refer to Exhibit E-1, Schedule 4.**

2. Provide a summary of test year adjustments which sets forth the effect of the adjustment upon the following: operating revenues, operating expenses, taxes other than income taxes, operating income before income taxes, State income tax, Federal income tax and income available for return

   **Response: Please refer to Exhibit E-4. Summary, Page 1 through 3.**

3. List and explain all nonrecurring or extraordinary expenses incurred in the test year and all expenses included in the test year which do not occur yearly but are of a nature that they do occur over an extended period of years, for example, non-yearly maintenance programs, and the like.

   **Response: The Company did not have any extraordinary or non-recurring expenses during the history Test Year (i.e., the Twelve Months Ended September 30, 2024).**

4. As a separate item, list extraordinary property losses related to property previously included in cost of service when the gain or loss on this property has occurred or is likely to occur in the future test

year. The proposed ratemaking treatment of extraordinary gains and losses must also be disclosed. Sufficient supporting data must be provided.

**Response: The Company did not have any extraordinary property gains or losses related to plant or other storm related damage to facilities from Hurricane Riley.**

5. Provide the amount of accumulated reserve for uncollectible accounts, method and rate of accrual, amounts accrued and amounts written off in each of the last 3 calendar years.

   **Response: As of December 31, 2023 Pike had an uncollectable reserve balance of $61,622. For the Twelve Months Ended December 31, 2023, 2022 and 2021 the actual amounts written off were $54,996.72, $41,170.36 and $30,337.90, respectively. Please note that the net uncollectible write-offs listed above are for both electric and gas revenues.**

6. Supply detailed calculations to support the total claim for rate case expense, including supporting data for outside service rendered. Provide the items comprising the estimated rate case expense claim for the current rate case.

   **Response: The Company estimated total rate case expense to be $250,000, of which 85% or 212,500 was allocated to electric operations. Outside consulting cost were estimated to be $85,000 for Legal Services, $75,000 for Accounting / Revenue Requirement, and $75,000 for Cost of Service / Rate Design. Printing and legal notices were estimated to be $15,000. The estimate is based on an assumption that the Company will be able to settle the Case with parties. The cost would be higher if the case must be litigated. The Company has limited internal resources available to devote to the rate filings and as a result, must rely on services provided by outside legal counsel and consultants.**

7. Submit schedules for the test year and for the 12-month period immediately prior to the test year showing by major components, if included in claimed test year expenses, the expenses incurred in each of the following expense categories.

a. Miscellaneous general expenses, including account 930.

b. Outside service expenses.

c. Regulatory commission expenses.

d. Advertising expenses, including advertising engaged in by trade associations whenever the utility has claimed a contribution to the trade association as a ratemaking claim—provide explanation of types and purposes of such advertising.

e. Research and development expenses—provide a listing of major projects.

f. Charitable and civic contributions, by recipient and amount.

Explain major variances between the test year expenses and those expenses for the prior 12-month period.

**Response: Please see the table below. Intercompany charges were escalated using the Consumer Price index of 1.0%. Direct expenses of Pike were not escalated. The amortization of deferred storm charges increased to reflect a four year amortization of Hurricane Riley and other minor storm costs. The four year amortization of projected rate case cost is shown**

**in Exhibit E-4, Schedule 9. Charitable contributions are charged below the line and were not included in the Company's rate request. The estimated level of donations for the future Test Year Ended September 30, 2025, was based on the actual contributions made by the Company over the last two fiscal years.**

| FERC Account | Description | Twelve Months Ended 09/30/24 | Twelve Months Ended 09/30/25 |
|---|---|---|---|
| 930 | Miscellaneous General Expense | | |
| | Direct Charges | 38,514 | 38,514 |
| | Intercompany Charges | 9,631 | 9,631 |
| 923 | Outside Service Expense | | |
| | Direct Charges | 197,397 | 205,293 |
| | Intercompany Charges | 193,080 | 200,804 |
| 928 | Regulatory Commission Expense: | | |
| | PaPUC Assessment | 38,066 | 38,066 |
| | Amortization of Deferred Storm Charges | 195,528 | 225,216 |
| | Amortization of Rate Case Costs | 61,613 | 114,713 |
| | All Other | 1,275 | - |
| 917 | Informational Advertising Expense | 30,589 | 30,589 |
| 930 | Research & Development Expense | - | - |
| 426 | Charitable Contributions | 2,175 | 532 |
| | | | |
| (a) | Charitable contributions are charged below the line and are not part of the Company's rate request. | | |
| (b) | Estimated based on the average contributions charged to account 426 for the twenty-four months ended September 30, 2024. | | |

8. Provide an analysis by function of charges by affiliates, for the test year and the 12-month period immediately prior to the test year, for services rendered included in the operating expenses of the filing company. Explain the nature of the service and the basis on which charges or allocations are made, including a copy of an applicable contract. Also, explain major variances between the charges for the test year and the corresponding charges for the prior 12-month period.

   **Response: Please refer to Exhibit E-1, Schedules 5 and 6 and Exhibit E-3, Schedule 1, Page 3. The testimony of Charles Lenns and Matthew Lenns discussed the intercompany cost allocations.**

9. Prepare a detailed schedule for the test year showing types of social and service organization memberships paid for, the cost thereof, the accounting treatment and whether included in claimed test year expenses.

   **Response: Below are the payments made to Service Organizations during the Twelve Months Ended September 30, 2024 that were charged to FERC account 917 and included in the Test Year level of expense:**

   **Pike County Chamber of Commerce $1,627.75**

| | |
|---|---|
| **Greater Pike Community Foundation** | **1,360.00** |
| **Total** | **$2,987.75** |

10. Provide the following payroll and employee benefit data—regular and overtime—separately for the test year and for the 12-month period immediately prior to the test year:

a. The average and year-end number of employees and the unadjusted annual payroll expense and employee benefit expense associated with union personnel.

**Response: Refer to response b. below for all employees included in payroll.**

b. The average and year-end number of employees and the unadjusted annual payroll expense and employee benefit expense associated with nonunion personnel.

**Response: Pike maintained a staff of 11 employees (9 union and 2 non-union) during the Twelve Months Ended September 30, 2024. Electric payroll expense shown on Exhibit E-4, Schedule 4 for Pike employees was $255,762. Administrative payroll costs allocated from Corning Natural Gas was $141,214. Total direct and allocated employee benefit expense including 401(k), employee benefit insurance costs and workers insurance costs, excluding payroll taxes was $424,813. Payroll taxes shown on Exhibit E-4, Schedule 13 amounted to $117,436.**

c. The average and year-end number of employee and the unadjusted annual payroll expense and employee benefit expense associated with management employee, if different than b.

**Response: N/A – Amounts included in 10b. above.**

d. A summary of the wage rate, salary and employee benefit changes granted or to be granted during the year.

**Response: The Company's annual overall wage increase was targeted to 4.0%.**

e. The claimed test year payroll expense and employee benefit expense. The percentage of payroll expense and employee benefit expense applicable to operation and maintenance expenses and the basis thereof.

**Response: The payroll expense for the Twelve Month Ended September 30, 2025 would be $422,104, including new hires. Total direct and allocated employee benefit expense, excluding payroll taxes would be $455,513. Payroll taxes shown on Exhibit E-4, Schedule 13 amounted to $36,881.**

**Payroll expense represents 12.2% ($422,104 / $3,452,900) of O&M excluding Purchased Power Costs. Employee benefit costs represent 13.2% ($455,513/$3,452,900) of O&M expenses excluding Purchased Power costs.**

11. Describe costs relative to leasing equipment, including computer rentals, and office space, including terms and conditions of the leases. State method for calculating monthly or annual payments.

**Response: Pike does not lease any Office equipment.**

12. Submit a statement of past and anticipated changes, since the previous rate case, in major accounting procedures, explain any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate cases, and list all internal and independent audit reports for the most recent 2 year period.

**Response: Pike was acquired by Corning Natural Gas Holding Company ("CNGH") in 2016, and On July 6 ,2022, Corning Natural Gas Holding Corporation was acquired by Argo Infrastructure Partners, and the Company's parent name was changed to Corning Energy Corporation. Since 2016, shared administrative expenses are allocated to Pike based on the allocation factors shown in Exhibit E-1, Schedule 6 and discussed testimony of Charles Lenns and Matthew Lenns. Further, shared administrative office space was allocated to Pike as shown in Exhibit E-3, Schedule 1, Page 3.**

13. Regardless of whether a claim for negative or positive net salvage is made, attach an exhibit showing gross salvage, cost of removal, third party reimbursements, if any, and net salvage for the test year and 4 previous years.

**Response: See Exhibit E-4, Schedule 12, Page 4. The Company has not updated the gross salvage, cost of removal, third party reimbursements study since acquisition. Data prior to the acquisition of Pike by Corning Natural Gas Holding Company in September 2016 is not available. The Company's filing reflects the levels of net salvage and removal costs included in Appendix C to Case R-2013-2397237.**

14. State the amount of debt interest utilized for test year income tax calculations, including the amount so utilized which has been allocated from the debt interest of an affiliate, and provide details of debt interest and allocation computations.

**Response: See Exhibit E-4, Schedule 14, page 3, column 1 for the interest expense utilized. Exhibit E-2, Schedule 1 shows the weighted cost of debt.**

15. Provide a schedule for the test year of Federal and Pennsylvania taxes other than income taxes, per books, pro forma at present rates, and pro forma at proposed rates, including the following tax categories:

**Response: See Exhibit E-4, Schedule 13.**

16. Submit a schedule showing the adjustments from taxable net income per books to taxable net income pro forma under existing rates and pro forma under proposed rates, together with an explanation of all normalizing adjustments.

**Response: See Exhibit E-4, Schedule 14**

17. Submit a schedule showing for the last 5 years the income tax refunds, plus interest—net of taxes, received from the Federal government due to prior years' claims.

**Response: The Company has not filed any claims for refunds of Federal income taxes, nor has it received any Federal income tax refunds, during the last 5 years.**

18. Furnish a breakdown of major items comprising prepaid and deferred income tax charges and other deferred income tax credits, reserves and associated reversals on liberalized depreciation.

**Response: See Exhibit E-3, Schedule 7. The Company has included as a Rate Base reduction deferred income tax liabilities, net of deferred income tax assets.**

19. Explain how the Federal corporate graduated tax rates have been reflected for rate case purposes. If the Pennsylvania jurisdictional utility is part of a multi-corporate system, explain how the tax savings are allocated to each member of the system.

**Response: Since the Tax Cuts and Jobs Act of 2017 (TCJA), the Federal Corporation income tax rate has been a flat 21%. As a result of the tax rate change** in TCJA, the Company adjusted its income tax accounts to reflect federal income taxes at a flat 21% tax rate.

20. Explain the treatment given to costs of removal in the income tax calculation and the basis for such treatment.

**Response: Pike currently capitalizes removal for assets removed from service and adds the removal cost to the depreciable basis of the replacement asset. For assets not replaced, Pike records the removal cost as a reduction in the reserve for accumulated depreciation, in order to offset the depreciation expense that was estimated on the date that the asset was placed in service.**

21. Show income tax loss/gain carryovers from previous years. Show loss/gain carryovers by years of origin and amounts remaining by years at the beginning of the test year.

**Response: The NOL carryovers are included in the consolidated tax return. Copies of consolidated income tax returns are available for inspection upon request. Pike records a deferred income tax asset for the tax benefit of its allocated share of consolidated net operating loss carryforwards. See schedules below.**

| PIKE COUNTY LIGHT & POWER COMPANY - PA Taxable NOLs | | | | |
|---|---|---|---|---|
| NOLs | | | | |
| | NOL Created | 7/6/2022 | 12/31/2022 | Remaining |
| 9/30/2018 | 1,373,020 | (454,651) | (364,326) | 554,043 |
| 9/30/2019 | 20,204 | | | 20,204 |
| 9/30/2020 | 535,440 | | | 535,440 |
| 9/30/2021 | 244,668 | | | 244,668 |
| 12/31/2023 | 1,400,833 | | | 1,400,833 |
| | 3,574,165 | (454,651) | (364,326) | 2,755,188 |
| | | | | |
| | | | | |
| 12/31/2022 | | | | |
| | | | | |
| Taxable Income | 853,402 | | | |
| State Tax | 57,414 | | | |
| State Taxable Income | 910,816 | | | |
| NOL | (364,326) | | | |
| Taxable income after NOL | 546,490 | | | |

| Corning Energy Corporation & Subs<br>Federal Net Loss Analytics 2012-2023 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Tax Year | ACP Crotona Holdings, LP | ACP Crotona Corp | Corning Energy Corporation | Corning Appliance Corporation | CNG | Pike | Total | Cumulative |
| 9/30/2012 | | | | | 2,908,148 | | 2,908,148 | 2,908,148 |
| 9/30/2016 | | | 346,325 | | | 89,701 | 436,026 | 3,344,174 |
| 9/30/2017 | | | 46,756 | | | | 46,756 | 3,390,930 |
| 9/30/2019 | | | 307,862 | | | 20,229 | 328,091 | 3,719,021 |
| 9/30/2020 | | | 595,683 | | 61,112 | 521,946 | 1,178,741 | 4,897,762 |
| 9/30/2021 | 15,588 | | 1,356,673 | | | 181,846 | 1,554,107 | 6,451,869 |
| 7/6/2022 | | | (553,630) | | (2,908,148) | (100,250) | (3,562,028) | 2,889,841 |
| 12/31/2022 | | 3,590 | 2,293,522 | 1,539,624 | - | - | 3,836,736 | 6,726,577 |
| 12/31/2023 | 1,314,005 | - | 865,625 | 25,801,716 | - | 1,399,384 | 29,380,730 | 36,107,307 |

22. State whether the company eliminates tax savings by the payment of actual interest on construction work in progress not in rate base claim.

**Response: Pike does not capitalize interest. Generally, projects are completed within the year in which the project commenced.**

23. Under section 1552 of the Internal Revenue Code (26 U.S.C.A. § 1552) and 26 CFR 1.1552-1 (1983), if applicable, a parent company, in filing a consolidated income tax return for the group, must choose one of four options by which it must allocate total income tax liability of the group to the participating

members to determine each member's tax liability to the Federal government (if this interrogatory is not applicable, so state):

a. State what option has been chosen by the group.

**Response: Pike was acquired by Corning Natural Gas Holding Company ("CNGH") in 2016, and On July 6 ,2022, Corning Natural Gas Holding Corporation was acquired by Argo Infrastructure Partners, and the Company's parent name was changed to Corning Energy Corporation, and is a member of the ACP Crotona Holdings LP Consolidated group. The group employs method 2 under Treasury Regulation 1.1552-1. Any differences between federal income taxes allocated among the group members and actual federal income tax per the consolidated income tax return is allocated to the common parent corporation. . Please note, however, that this regulation provides guidance on how a group allocates income taxes solely for purposes of determining earnings and profits of the groups' members, and is not relevant for purposes of determining how actual income tax liability is shared among members of the group. Treasury regulation 1.1502-6 provides that all members of the group are severally liable for the groups' income tax liability.**

| Corning Energy Corporation Federal Taxable Income 2022-2023 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Tax Year | ACP Crotona Holdings LP | ACP Crotona Corp | CEC | CNG | Appliance | Pike | Consolidated |
| 7/6/2022 | | | (1,160,931) | 226,042 | 22,891 | 992,949 | 80,951 |
| 12/31/2022 | | (3,590) | (2,293,522) | (1,539,624) | | | (3,836,736) |
| 12/31/2023 | (1,314,005) | - | (865,625) | (25,801,716) | | (1,399,384) | (29,380,730) |

b. Provide, in summary form, the amount of tax liability that has been allocated to each of the participating members in the consolidated income tax return for the test year and the most recent 3 years for which data is available.

**Response: The following table summarizes taxable results for the last three filed tax returns for the fiscal years ended December 31, 2023, December 31, 2022 and July 6. 2022:**

| | Fiscal 12/31/2023 | | | | | |
|---|---|---|---|---|---|---|
| | ACP Crotona Holdings LP | ACP Crotona Corp. | Corning Energy Corporation | Corning Natural Gas | Corning Appliance | Pike |
| Tax Income | $ 189,595 | $ 1,500,000 | $ (866,521) | $ (32,731,448) | $ 30,421 | $ (1,493,011) |
| NOL / Deduct | 1,500,000 | 1,500,000 | - | 5,277 | - | - |
| Taxable Income | $ (1,310,405) | $ - | $ (866,521) | $ (32,736,725) | $ 30,421 | $ (1,493,011) |
| Tax Liability | | | $ (6,388) | | $ 6,388 | |

| | Fiscal 12/31/2022 | | | | | |
|---|---|---|---|---|---|---|
| | ACP Crotona Holdings LP | ACP Crotona Corp. | Corning Energy Corporation | Corning Natural Gas | Corning Appliance | Pike |
| Tax Income | $ 12,959 | $ 34,308 | $ (1,496,923) | $ (363,711) | $ 15,261 | $ 924,235 |
| NOL / Deduct | - | 38,723 | - | 9,360 | - | - |
| Taxable Income | $ 12,959 | $ (4,415) | $ (1,496,923) | $ (373,071) | $ 15,261 | $ 924,235 |
| Tax Liability | | $ 2,721 | $ (200,014) | | $ 3,204 | $ 194,089 |

| | Fiscal 7/06/2022 | | | |
|---|---|---|---|---|
| | Corning Energy Corporation | Corning Natural Gas | Corning Appliance | Pike |
| Tax Income | $ (607,301) | $ 3,301,975 | $ 22,891 | $ 1,068,473 |
| NOL / Deduct | - | 2,987,987 | - | 813,722 |
| Taxable Income | $ (607,301) | $ 313,988 | $ 22,891 | $ 254,751 |
| Tax Liability | $ (124,234) | $ 65,937 | $ 4,800 | $ 53,497 |

c. Provide a schedule, in summary form, of contributions, which were determined on the basis of separate tax return calculations, made by each of the participating members to the tax liability indicated in the consolidated group tax return. Provide total amounts of actual payments to the tax depository for the tax year, as computed on the basis of separate returns of members.

**Response: See schedule in response to question 23(b) above.**

d. Provide the most recent annual income tax return for the group.

**Response: The Company's annual income tax return is confidential, and can be provided as a separate communication to the PAPUC.**

e. Provide details of the amount of the net operating losses of any member allocated to the income tax returns of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years.

**Response: See response to question 23(b). See attached schedule**

f. Provide details of the amount of net negative income taxes, after all tax credits are accounted for, of any member allocated to the income tax return of each of the members of the consolidated group for the test year and the 3 most recent years for which data is available, together with a summary of the actual tax payments for those years.

**Response: See response to 23(b).**

24. Provide detailed computations by vintage year showing State and Federal deferred income taxes resulting from the use of accelerated tax depreciation associated with post-1969 public utility property, ADR rates, and accelerated tax depreciation associated with post-1980 public utility property under the Accelerated Cost Recovery System (ACRS).

a. Reconcile and explain any differences in the base used to calculate State and Federal deferred income taxes.

**Response: Pike was acquired in 2014. As a result, all assets are being depreciated under the current Modified Accelerated Cost Recovery System (MACRS). The basis for all plant assets is the same for State and Federal deferred income taxes. See attached schedule.**

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing – Docket No. R-2024-3052359

Responses to Data Requests Under Section 53.53

| | TAX | BOOK | VARIANCE |
|---|---|---|---|
| **Cost** | | | |
| Beginning Balance | 35,071,243 | 39,582,591 | (4,511,348) |
| PY True-up | - | | - |
| Adj. Beginning Balance | 35,071,243 | 39,582,591 | (4,511,348) |
| Additions | | | - |
| Disposals | - | | - |
| Repairs and Maintenance | | | - |
| Other Adjustments | 169,951 | | 169,951 |
| Ending Balance | 35,241,194 | 39,582,591 | (4,341,397) |
| | **Note A** | **Note B** | |
| **Accumulated Depreciation** | | | |
| Beginning Balance | (11,219,097) | (4,947,289) | (6,271,808) |
| PY True-up | 77,077 | - | 77,077 |
| Adj. Beginning Balance | (11,142,020) | (4,947,289) | (6,194,731) |
| Additions | | | - |
| Disposals | - | - | - |
| Repairs and Maintenance | | | - |
| Other Adjustments | (54,272) | | (54,272) |
| Ending Balance | (11,196,292) | (4,947,289) | (6,249,003) |
| | **Note A** | | |
| | | | Fed DTA (DTL) |
| **Net Value** | 24,044,902 | 34,635,302 | (10,590,400) |

g. State whether tax depreciation is based on all rate base items claimed as of the end of the test year, and whether it is the annual tax depreciation at the end of the test year.

**Response: The tax depreciation accrual was based on plant in service as of December 31, 2023.**

h. Reconcile differences between the deferred tax balance, as shown as a reduction to rate base, and the deferred tax balance as shown on the balance sheet.

**Response: The Company started with the per book deferred tax balance and added the accrual shown on Exhibit E-3, Schedule 9.**

25. Submit a schedule showing a breakdown of accumulated and unamortized investment tax credits, by vintage year and percentage rate, together with calculations supporting the amortized amount claimed as a reduction to pro forma income taxes. Provide details of methods used to write-off the unamortized balances.

**Response: Pike was acquired from Orange and Rockland Utilities, Inc. in 2016 and does not have an unamortized investment tax credit deferred tax.**

26. Explain in detail by statement or exhibit the appropriateness of claiming any additional items, not otherwise specifically explained and supported in the statement of operating income.

**Response: N/A – The Company is not claiming any items not supported in the statement of operating income.**

27. If the utility's operations include non-jurisdictional activities, provide a schedule which demonstrates the manner in which rate base and operating income date have been adjusted to develop the jurisdictional test year claim.

**Response: N/A – The Company is not including any non-jurisdictional activities.**

## E. BUDGETED DATA

1. Supply a copy of any budget utilized as a basis for any test year claim, and explain the utility's budgeting process.

**Response: Pike's capital budget for 2025 and 2026 is shown on Exhibit E-3, Schedules 10 and 11.**

2. Supply summaries of the utility's projected operating and capital budgets for the 2 calendar years following the end of the test year.

**Response: Below is the Five Year Capital budget for Pike. The Company does not yet have a final operating budget for the next two calendar years following the end of the test year.**

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing – Docket No. R-2024-3052359

Responses to Data Requests Under Section 53.53

| Electric Distribution Plant | | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|
| **LTIIP Program:** | | | | | | |
| Additional Defective Pole Replacement and Storm Hardening | | $ 1,225 | $ 1,363 | $ 1,423 | $ 2,087 | $ 1,404 |
| 69 x 34.5 kV Substation | | 1,150 | 3,650 | 2,500 | 2,500 | - |
| Purchase 69 kV x 34.5 kV-35MVA SubTransformer (for 2027 LTIIP program) | | 250 | 750 | - | - | - |
| PJM Interconnect 69kv Line | | - | 500 | 900 | - | - |
| Extend 34.5 kV RT 84 to Martin Road on Rt 6 (proposed location of new station) | | - | - | 525 | 375 | - |
| State Grants | | (700) | (2,450) | (1,963) | (1,438) | - |
| | | - | - | - | - | - |
| **Subtotal LTIP** | | **$ 1,925** | **$ 3,813** | **$ 3,386** | **$ 3,525** | **$ 1,404** |
| **Recurring Captial Budget Upgrades / Replacements** | | | | | | |
| Station Equipment | 362 | 263 | 276 | 289 | 304 | 319 |
| Residential Meters | 364 | 21 | 22 | 23 | 24 | 26 |
| Electric Light & Substation Upgrades | 368 | 32 | 33 | 35 | 36 | 38 |
| Services-O/H | 369 | 63 | 86 | 69 | 73 | 77 |
| Meters-EM Purchases | 370 | 1,728 | 400 | 418 | 437 | 457 |
| **Subtotal Recurring Upgrades / Replacements** | | **$ 2,106** | **$ 817** | **$ 835** | **$ 875** | **$ 916** |
| | | | | | | |
| **Total Electric Distribution Plant** | | **$ 4,031** | **$ 4,630** | **$ 4,221** | **$ 4,399** | **$ 2,320** |
| | | | | | | |
| **Gas Distribution Plant** | | | | | | |
| **LTIIP Program:** | | | | | | |
| Pipe Replacement Progarm (LTIIP) | 376 | **$ 1,353** | **$ 2,059** | **$ 1,585** | **$ 1,818** | **$ 3,711** |
| **Subtotal LTIP** | | | | | | |
| **Recurring Captial Budget Upgrades / Replacements** | | | | | | |
| Mains | 376 | 120 | 123 | 100 | 113 | 209 |
| Measuring and Regulating Station Equipment | 378 | 55 | 57 | 60 | 63 | 66 |
| Services | 380 | 781 | 132 | 139 | 146 | 153 |
| Meters | 381 | 13 | 14 | 14 | 15 | 16 |
| House Regulators | 383 | 105 | 110 | 116 | 122 | 128 |
| **Subtotal Recurring Upgrades / Replacements** | | **$ 1,073** | **$ 436** | **$ 429** | **$ 459** | **$ 572** |
| | | | | | | |
| **Total Gas Distribution Plant** | | **$ 2,427** | **$ 2,494** | **$ 2,014** | **$ 2,277** | **$ 4,284** |
| | | | | | | |
| **General Plant** | | | | | | |
| Office Furniture | 390 | 71 | 51 | 12 | 12 | 13 |
| IT Equipment | 391 | 237 | 39 | 41 | 43 | 45 |
| Transportation Equipment | 392 | 150 | 125 | 60 | 60 | 60 |
| Contractor Work / Other | | 231 | 249 | 224 | 233 | 130 |
| Tools, Shop and Garage Equipment | 394 | 24 | 25 | 26 | 28 | 29 |
| **Total General Plant Upgrades / Replacements** | | **$ 712** | **$ 489** | **$ 363** | **$ 376** | **$ 277** |
| | | | | | | |
| **Total Electric, Gas & General Plant** | Total | **$ 7,170** | **$ 7,613** | **$ 6,598** | **$ 7,052** | **$ 6,880** |

## *III. RATE OF RETURN*

# A. CLAIMED RATE OF RETURN

1. Provide a schedule showing the major components of claimed capitalization, and the derivation of the weighted costs of capital for the rate case claim. This schedule shall include a descriptive statement concerning the major elements of changes in claimed capitalization, cost rates and overall return from comparable historical data.

**Response: Please refer to Exhibit E-2 for the derivation of the weighted cost of capital. Please refer to pages 18-21 of the testimony offered by Charles Lenns and Matthew Lenns for the description of the major elements in the capitalization, the cost rates and the overall rate of return.**

2. Provide a schedule in the same format as Schedule 1, except for the omission of the descriptive statement, for the most immediate comparable annual historical period prior to the test year and the two calendar years most immediately preceding the rate of return claim period. Irrespective of whether the capitalization claimed on Schedule 1 includes short-term debt, Schedule 2 should reflect capital ratios with and without short-term debt.

**Response: Please refer to Exhibit E-2 for the Twelve Months Ended September 30, 2024. Refer below for the capital structures of Pike for the two calendar years ended December 31, 2023 and December 31, 2022:**

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing – Docket No. R-2024-3052359

Responses to Data Requests Under Section 53.53

| | As of December 31, 2023 | |
|---|---|---|
| | Amount | Percent |
| Long Term Debt: | $ 13,371,504 | 44.40% |
| Average Short Term Debt (a) | 1,705,741 | 5.66% |
| Proprietary Capital | | |
| Common Stock | - | |
| Paid In Capital | 9,732,500 | |
| Retained Earnings | 5,306,350 | |
| Total Proprietary Capital: | 15,038,850 | 49.94% |
| Total Capitalization | $ 30,116,095 | 100.00% |

| | As of December 31, 2022 | |
|---|---|---|
| | Amount | Percent |
| Long Term Debt: | $ 11,988,596 | 46.93% |
| Average Short Term Debt (a) | 2,177,800 | 8.53% |
| Proprietary Capital | | |
| Common Stock | - | |
| Paid In Capital | 8,372,500 | |
| Retained Earnings | 3,004,718 | |
| Total Proprietary Capital: | 11,377,218 | 44.54% |
| Total Capitalization | $ 25,543,614 | 100.00% |

## B. EMBEDDED COST OF LONG-TERM DEBT

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing – Docket No. R-2024-3052359

Responses to Data Requests Under Section 53.53

1. Provide a schedule showing the calculation of embedded cost of long-term debt by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue.

b. Date of maturity.

c. Amount issued.

d. Amount outstanding.

e. Amount retired.

f. Amount reacquired.

g. Gain or loss on reacquisition.

h. Coupon rate.

i. Discount or premium at issuance.

j. Issuance expense.

k. Net proceeds.

l. Sinking fund requirements.

m. Effective cost rate.

n. Total average weighted effective cost rate.

Projected new issues, retirements and other major changes from the comparable historic data should be clearly noted.

**Response: Please refer to Exhibit E-2, Schedules 2 and 3.**

2. In the event that a claim made for a true or economic cost of debt exceeds that shown in the preceding nominal cost schedule because of convertible features, sale with warrants or for any other reason, a full statement of the basis for such a claim should be provided.

**Response: N/A – The Company's debt is at its nominal cost.**

3. Provide the following information concerning bank notes payable for test year and for latest comparable annual historical period prior to the test year:

a. Line of credit at each bank.

b. Average daily balances of notes to each bank, by name of bank.

c. Interest rate charged on each bank note (Prime rate, formula rate, or other).

d. Purpose of each bank note (for example, construction, fuel storage, working capital, debt retirement).

e. Prospective future need for this type of financing.

**Response: Refer to Exhibit E-2 for all debt held at Pike. Corning Energy Corporation refinanced all external debt on September 12, 2024 with private investors, and established a new revolving credit line with Citizens Bank. During the Twelve Months ended September 30, 2024, the average daily short-term loan balance was $2,006,792 as shown on Exhibit E-2, Schedule 1, and the interest rate on the short-term loan was 7.21% as of the Test Year date of September 30, 2024. The short-term borrowings are used to fund construction and normal daily operations as needed. The Company anticipates the level of short-term borrowings will increase in the future Test Year ended September 30, 2025.**

4. Provide detailed information concerning all other short-term debt outstanding.

**Response: The Company does not have any other short-term debt outstanding.**

5. Describe long-term debt reacquisition by issue by Company and Parent as follows:

   a. Reacquisition by issue by year.

   b. Total gain or loss on reacquisitions by issue by year.

   c. Accounting for gain or loss for income tax and book purposes.

   d. Proposed treatment of gain or loss on such reacquisition for ratemaking purposes.

**Response: Refer to response 3. Above for details.**

## C. EMBEDDED COST OF PREFERRED STOCK

Provide a schedule showing the calculation of the embedded cost of preferred stock equity by issue, supporting the related rate case claim. The schedule shall contain the following information:

a. Date of issue.

b. Date of maturity.

c. Amount issued.

d. Amount outstanding.

e. Amount retired.

f. Amount reacquired.

g. Gain or loss on reacquistion.

h. Dividend rate.

i. Discount or premium at issuance.

j. Issuance expenses.

k. Net proceeds.

l. Sinking fund requirements.

m. Effective cost rate.

n. Total average weighted effective cost rate.

Projected new issues, retirement and other major changes from the comparable historical data should be clearly noted.

**Response: Pike does not have Preferred Stock.**

## D. COST OF COMMON EQUITY

1. Provide complete support for claimed common equity rate of return.

**Response: The requested return on Common Equity of 9.75% was based on the Commission current guidelines.**

2. Provide a summary statement of all stock dividends, splits or par value changes during the 2 calendar year period preceding the rate case filing.

**Response: Pike has not paid any stock dividends, splits or par value changes during the 2 calendar year period preceding the rate case filing.**

3. Provide a schedule of all issuances of common stock, whether or not underwriters are used, for the most immediately available annual historical period and the 2 calendar years most immediately preceding the test year.

**Response: Pike has not issued any common stock during the test period or in any of the two calendar periods preceding the test year.**

4. Submit details on the utility and parent company stock offerings—past 5 years to present—as follows:

a. Date of prospectus.

b. Date of offering.

c. Record date.

d. Offering period—dates and numbers of days.

e. Amount and number of shares offered.

f. Offering ratio, if rights offering.

g. Percent subscribed.

h. Offering price.

i. Gross proceeds per share.

j. Expenses per share.

k. Net proceeds per share (i—j).

l. Market price per share.

(1) At record date.

(2) At offering date.

(3) One month after close of offering.

m. Average market price during offering.

(1) Price per share.

(2) Rights per share—average value of rights.

n. Latest reported earnings per share at time of offering.

o. Latest reported dividends at time of offering.

**Response: All stock of Pike and its parent company are owned by ACP Crotona Holdings LP, which were acquired as part of the acquisition on July 6, 2022. There have been no other issuances of common stock.**

## E. PARENT—SUBSIDIARY RELATIONSHIP

1. If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system—consolidated—the reasons for this claim must be fully stated and supported.

**Response: Pike filing is based on its stand alone capital structure.**

2. Regardless of the claim made, provide the capitalization data requested at Item III.A.2. for the parent company and for the system—consolidated.

**Response: Corning Energy Consolidated financial statements are maintained, however as this is a private company, the financial results cannot be included as part of this public filing. Consolidated financial statements and tax returns were submitted as confidential files.**

3. Provide the latest available balance sheet and income statement for the parent company and system—consolidated.

**Response: Corning Energy Consolidated financial statements are maintained, however as this is a private company, the financial results cannot be included as part of this public filing. Consolidated financial statements and tax returns were submitted as confidential files.**

4. Provide an organizational chart explaining the filing utility's corporate relationship to its affiliates—system structure.

**Response: Corning Energy Consolidated financial statements are maintained, however as this is a private company, the financial results cannot be included as part of this public filing. Consolidated financial statements and tax returns were submitted as confidential files.**

## F. GENERAL FINANCIAL DATA

**Pike County Light and Power Company, Inc.**

Electric Rate Case Filing – Docket No. R-2024-3052359

Responses to Data Requests Under Section 53.53

1. The latest available quarterly operating and financial report, annual report to the stockholders and prospectus shall be supplied for the utility and for the utility's parent, if the relationship exists.

**Response: Corning Energy Consolidated financial statements are maintained, however as this is a private company, the financial results cannot be included as part of this public filing. Consolidated financial statements and tax returns were submitted as confidential files.**

2. Supply projected capital requirements and sources of the filing utility, its parent and system—consolidated—for the test year and each of 3 comparable future years.

Response: Please refer to the Company's response to question Section 2, Question E-2 above for the Company's projected Capital requirements. Pike plans to draw on short-term debt and utilize future earnings to fund Capital expenditures. Pike's objective is to maintain a balanced capital structure comprised of approximately 50% debt and 50% equity.

3. State what coverage requirements or capital structure ratios are required in the most restrictive of applicable indentures/charter tests and how these measures have been computed.

**Response: The Company has debt covenants as part of the debt refinancing that occurred on September 12, 2024, with private investors, along with Citizens Bank, as follows:**

**Consolidated Indebtedness to Capitalization Ratio**

**The Company shall not permit the Consolidated Indebtedness to Capitalization Ratio as of the end of each fiscal quarter of the Company to be greater than 0.65 to 1.0.**

**Interest Coverage Ratio**

**The Company shall not permit the Interest Coverage Ratio as of the last day of any computation period be less than 2.00 to 1.00.**

**The Company must satisfy these covenants on a quarterly basis. We submitted the first covenant calculation to the private investors and Citizens Bank for Q3 2024, and they agreed with our conclusions.**

4. A schedule of comparative financial data shall be supplied for the test year, the most immediately available annual historical period, prior to the test year, and the 2 calendar years most immediately preceding the test year. Changes in Moody's/S&P ratings, noted on this schedule, shall be accompanied by the Moody's/S&P writeup of such change, if available. The following financial data and ratios shall be supplied for the utility's parent, where applicable, if not available for the utility.

a. Times interest earned ratio—pre-tax and post-tax basis.

b. Preferred stock dividend coverage ratio—post-tax basis.

c. Times fixed charges earned ratio—pre-tax basis.

d. Earnings per share.

e. Dividend per share.

f. Average dividend yield (52-week high/low common stock price).

g. Average book value per share.

h. Average market price per share.

i. Market price-book value ratio.

j. Earnings-book value ratio (per share basis, average book value).

k. Dividend payout ratio.

l. AFUDC as a % of earnings available for common equity.

m. Construction work in progress as a % of net utility plant.

n. Effective income tax rate.

o. Internal cash generations as a % of total capital requirements.

**Response: Corning Energy Consolidated financial statements are maintained, however as this is a private company, the financial results cannot be included as part of this public filing. Consolidated financial statements and tax returns were submitted as confidential files.**

## *IV. RATE STRUCTURE AND COST ALLOCATION*

## A. SUMMARY OF INDIVIDUAL RATE EFFECTS

Provide a summary schedule of the individual rate effects. For each state jurisdictional rate, show the following information for the test period elected:

1. Rate schedule designation.

**Response: Please see Exhibit E-8 for all individual rates and rate design for both present rates and proposed rates.**

2. For existing rates:

(a) Customers served as of end of period.

(b) Annual Kwh sales.

(c) Base rate revenues adjusted for any changes in base rate application that may have occurred during the test period.

(d) Tax surcharge revenues.

(e) Energy Cost adjustment clause revenues.

(f) Revenues received from other clauses or riders separately accounted for.

(g) Total of all revenues.

**Response: Please see Exhibit E-8 for all individual rates and rate design for both present rates and proposed rates.**

3. For proposed rates:

(a) Estimated number of customers whose charges for electric service will be increased or decreased as a result of this filing.

(b) Base rate revenues:

(1) Annual dollar amount of increase or decrease.

(2) Percentage change.

(c) Estimated tax surcharge revenues based on the assumption that the base rate changes proposed were in place.

(d) Estimated Energy cost adjustment clause revenues.

(e) Revenues received from other clauses or riders separately accounted for.

(f) Total of all revenues:

(1) Amount of total annual dollar change.

(2) Percentage change.

**Response: All customers would see an increase based on the Company's filing. Please see Exhibit E-8 for all individual rates and rate design for both present rates and proposed rates. Further, please see Exhibit E-4 for the base rate increase and breakdown of all revenues.**

4. Supplement the revenue summary to obtain a complete revenue statement of the electric business, that is, show delayed payments, other electric revenues, FERC jurisdictional sales and revenues and all other appropriate revenue items and adjustments.

**Response: See Exhibit E-4, Schedule 1, Page 2.**

5. Develop the grand total showing total sales and revenues as adjusted and the various increases and decreases and percent effects as described above.

**Response: See Exhibit E-4, Summary.**

## B. DESCRIPTION OF PROPOSED RATE CHANGES

Provide a description of changes proposed for the new tariff:

(1) For each rate schedule proposed to be modified.

(2) For each rate schedule proposed to be deleted.

(3) For each new rate schedule proposed to be added.

**Response: The tariffs were updated for reflect the requested delivery rate changes.**

## C. REVENUE EFFECTS AND BILLING ANALYSES FOR CHANGED RATES

The annual revenue effect of any proposed change to any rate must be supported by a billing analysis. This may consist of the use of bill frequency distributions or individual customer billing records for the most recent annual periods available. All billing determinants should be displayed. The blocking and corresponding prices of the existing rate and the proposed rate should be applied to the determinants to derive the base rate revenues under both present and proposed rates. The derived base rate revenues should form the basis for measuring the annual base rate effect of the rates in question for the test periods.

**Response: Please see Exhibit E-8 for all individual rates and rate design for both present rates and proposed rates.**

## D. MONTHLY BILLING EFFECT CHARTS AND DATA

The effects of the proposed rates on monthly billing conditions should be provided as follows:

*1. Residential Bill Comparisons*

For each rate applicable to residential service provide a chart or tabulation which shows the dollar and percentage effect of the proposed base rate on monthly bills ranging from the use of zero kWh to 5,000 kWh at appropriate intervals.

*2. General Bill Comparisons*

For each rate that requires both a billing demand (kW) and kWh's as the billing determinants, provide a tabulation or graphical comparison showing the percentage effect of the proposed base rate on monthly bills using several representative demand (kW) levels, the monthly kWh for each demand selected to be in load factor increments of 10% starting at 0% and ending at 100% (730H) or by hours' use increments that covers approximately 95% of the bills.

**Response: Please see Exhibit E-8 for all individual rates and rate design for both present rates and proposed rates.**

## E. COST OF SERVICE STUDY, ALLOCATIONS TO EACH TARIFF RATE SCHEDULE

1. Provide a cost study which allocates the total cost of service to each proposed tariff rate schedule. Tariff rates schedules may be combined for this purpose provided that they are of a similar supply or end use nature. A statement describing which rates were combined and the reasons therefore should be submitted.

The rates of return for each tariff rate schedule as defined above should be determined at both the present and proposed rate levels. Base rate revenues should be used for this purpose unless there are good and sufficient reasons to include revenues derived from other sources. Should the latter be the case, an explanation of other revenue sources included and reasons therefore should accompany the cost allocation study.

**Response: Please see Exhibit E-6, Schedule PMN-3-E.**

The methods selected for use in allocating costs to rate classes should include cost analyses based on:

a. Peak responsibility.

b. Average and excess, on a non-coincident demand basis.

c. Company preferred method if different from the above-referenced methods, with rationale behind the selection.

**Response: The description of the demand allocators are in Exhibit E-6.**

This study should include a statement of the source and age of the load data used in the determination of demand responsibilities, a description of any special studies used to prepare the cost study, and the most recent overall system line loss study.

The cost data used in the allocation study may be based on the test year.

2. Provide comparisons in either graphical or tabular form showing cost, as defined in the cost of service study, and proposed base rate revenues and usage for all residential and demand/energy rate schedules. Demand shall be for representative loads for each demand/energy rate schedule.

**Response: The bill comparisons can be found in Exhibit E-8.**

## *V. PLANT AND DEPRECIATION SUPPORTING DATA, INCLUDING RELATED DEPRECIATION STUDY REPORT*

### A. ADJUSTED ORIGINAL COST PLANT WITH ACCUMULATED BOOK AND CALCULATED DEPRECIATION AT TEST YEAR-END

1. Provide schedules supporting claimed amounts for Electric Plant in Service by function and by account if available.

**Response: Refer to Schedule E-1, Schedule 2.**

2. Provide a comparison of calculated depreciation reserve versus book reserve at the end of the test year. Provide this comparison by functional group and by account if available.

**Response: The Company has not performed a depreciation study to calculate a theoretical reserve balance.**

3. Provide supporting schedules which indicate the procedures and calculations employed to develop the original cost plant and applicable reserves to the test year end as submitted in the current proceeding.

**Response: Refer to Schedule E-1, Schedule 2.**

4. Provide a schedule showing details of rate case adjustments.

**Response: Please refer to Exhibit E-3, Schedule 2 and Exhibit E-4, Schedule 12.**

## B. ADJUSTED ORIGINAL COST ANNUAL BOOK AND CALCULATED DEPRECIATION ACCRUALS

1. Provide a comparison of calculated depreciation accruals versus book accruals by function and by account if available.

**Response: N/A – The Company did not perform a calculation to compare its depreciation accruals to booked accruals.**

2. Supply a schedule by account or by depreciable group showing the survivor curve or interim survivor curve and annual accrual rate estimated to be appropriate:

a. For the purpose of this filing.

**Response: The Company did not perform a depreciation study for this filing.**

b. For the purpose of the most recent rate filing prior to the current proceeding.

**Response: The Company does not have a study from the prior proceeding.**

c. Supply an explanation for any major change in annual accrual rate by account or by depreciable group.

**Response: There are no changes in accrual rates by account or by depreciable group.**

d. Supply a comprehensive statement of major changes made in depreciation methods, procedures and techniques and the effect of the changes upon accumulated and annual depreciation, if any.

**Response: The Company is not proposing any changes in this filing.**

## C. USE OF RETIREMENT RATE ACTUARIAL METHOD

Where the retirement rate actuarial method of mortality analysis is utilized, set forth representative examples including charts depicting the observed and estimated survivor curves and a tabular presentation of the observed and estimated life tables plotted on the chart. Other analysis results shall be subject to request.

**Response: The Company did not perform a depreciation study for this filing.**

## D. EXAMPLE TABULATIONS OF ORIGINAL COST CLAIMED ESTIMATES OF ACCRUED DEPRECIATION

1. Provide the surviving original cost plant at the appropriate test year date or dates by account or functional property group and include claimed depreciation reserves. Provide annual depreciation accruals where appropriate. These calculations should be provided for plant in service as well as other categories of plant, including but not limited to, contributions in aid of construction, customers' advances for construction, and anticipated retirements associated with construction work in progress claims, if applicable.

**Response: N/A – The Company did not perform a depreciation study.**

2. Provide representative examples of detail calculations by vintage at account or at a more detailed level, as performed for these purposes. Other vintage detail calculations shall be subject to request.

**Response: N/A – The Company did not perform a depreciation study.**

## E. DESCRIPTION OF DEPRECIATION METHODS

Provide a description of the depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of the significant factors which were considered in arriving at estimates of service life and forecast retirements by facilities, accounts or sub-accounts, as applicable.

**Response: The Company accrues depreciation utilizing the current rates in effect. To this amount it adds the current allowance for removal and negative salvage costs. The Company did not perform a depreciation study and has not forecast estimated asset service lives or retirements by facilities, accounts or sub-accounts.**

# *VI. UNADJUSTED COMPARATIVE BALANCE SHEETS AND OPERATING INCOME STATEMENTS*

Provide the following unadjusted detailed schedules by function and by FERC account for the claimed test year and for each of the 3 preceding comparable years:

A. Balance sheet, in the form available.

B. Statement of income.

C. Plant in service.

**Pike County Light and Power Company, Inc.**

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D. Accumulated depreciation.

## Response: Refer to the schedules below.

| | September 30 2024 | September 30 2023 | September 30 2022 | September 30 2021 |
|---|---|---|---|---|
| ASSETS AND OTHER DEBITS | | | | |
| Utility Plant | | | | |
| Electric Plant in Service | $ 34,737,197 | $ 26,195,778 | $ 23,586,680 | $ 21,164,789 |
| Gas Plant in Service | 7,193,512 | 6,182,000 | 4,660,232 | 3,092,660 |
| Common Plant in Service | 1,463,869 | 1,700,322 | 1,700,322 | 2,010,233 |
| Construction Work in Progress | 3,020,281 | 5,777,071 | 3,205,660 | 3,051,565 |
| Total Utility Plant | 46,414,860 | 39,855,171 | 33,152,895 | 29,319,246 |
| Accumulated Provision for Depreciation | | | | |
| Electric | 4,247,701 | 3,402,324 | 2,424,802 | 1,957,795 |
| Gas | 569,683 | 418,338 | 318,992 | 243,697 |
| Common | 1,328,583 | 1,038,894 | 1,159,519 | 1,258,862 |
| Total Accumulated Provision for Depreciation | 6,145,966 | 4,859,557 | 3,903,314 | 3,460,353 |
| Net Utility Plant | 40,268,894 | 34,995,614 | 29,249,581 | 25,858,893 |
| Other Property and Investments | | | | |
| Nonutility Property | - | - | - | - |
| Accumulated Provision for Depreciation | - | - | - | - |
| Net Other Plant | - | - | - | - |
| Current and Accrued Assets | | | | |
| Cash | 820,047 | 395,466 | (60,764) | (35,292) |
| Customer Accounts Receivable | 1,727,192 | 1,568,338 | 1,911,507 | 1,483,635 |
| Other Accounts Receivable | (24,235) | (76,788) | (45,585) | 25,048 |
| Accumulated Provision for Uncollectible Accounts | (43,714) | 12,510 | (10,945) | (32,467) |
| Accounts Receivable from Associated Companies | 154,076 | 82,021 | 104,381 | 740,560 |
| Materials and Supplies | 1,893,323 | 2,934,718 | 2,188,784 | 1,394,020 |
| Prepayments | (96,386) | (680,976) | 94,402 | 247,699 |
| Total Current and Accrued Assets | 4,430,302 | 4,235,288 | 4,181,779 | 3,823,203 |
| Deferred Debits | | | | |
| Unamortized Debt Expense | 632,375 | 78,178 | 85,118 | 85,192 |
| Other Regulatory Assets | 1,571,972 | 902,248 | 1,873,546 | 2,851,138 |
| Clearing Accounts | - | - | - | - |
| Miscellaneous Deferred Debits | 369,174 | 206,347 | 213,256 | (5,905) |
| Regulatory Asset State Provision | 970,799 | 779,751 | 708,191 | - |
| Total Deferred Debits | 3,544,320 | 1,966,524 | 2,880,111 | 2,930,425 |
| Total Assets and Other Debits | $ 48,243,515 | $ 41,197,426 | $ 36,311,471 | $ 32,612,521 |

# Pike County Light and Power Company, Inc.

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Responses to Data Requests Under Section 53.53

| | September 30 2024 | September 30 2023 | September 30 2022 | September 30 2021 |
|---|---|---|---|---|
| LIABILITIES AND OTHER CREDITS | | | | |
| Proprietary Capital | | | | |
| Common Stock Issued | $ - | $ - | $ - | $ - |
| Miscellaneous Paid-In Capital | 12,450,000 | 9,950,000 | 9,600,000 | 9,600,000 |
| Retained Earnings | 7,303,955 | 6,556,769 | 5,173,800 | 3,527,544 |
| Total Proprietary Capital | 19,753,955 | 16,506,769 | 14,773,800 | 13,127,544 |
| Long Term Debt | | | | |
| Bonds - Long-Term | 17,487,035 | 15,285,319 | 14,542,993 | 13,457,269 |
| Total Capitalization | 37,240,990 | 31,792,088 | 29,316,793 | 26,584,813 |
| Noncurrent Liabilities | | | | |
| Long Term Obligations | - | - | - | - |
| Total Noncurrent Liabilities | - | - | - | - |
| Current and Accrued Liabilities | | | | |
| Notes Payable | 1,869,665 | 2,617,121 | 2,004,314 | 1,692,047 |
| Accounts Payable | 1,857,957 | 1,688,121 | 1,229,260 | 879,253 |
| Accounts Payable to Associated Companies | 3,403,766 | 1,328,167 | 305,475 | 521,447 |
| Tax Collections Payable | (297,427) | (288,355) | 62,980 | 51,064 |
| Customer Deposits | 395,955 | 365,261 | 265,629 | 214,908 |
| Taxes Accrued - Federal | (41,107) | 223,527 | 144,794 | 16,536 |
| - Other | 1,541 | 126,767 | 16,084 | (58,354) |
| Interest Accrued | 17,403 | 9,966 | 3,955 | 4,087 |
| Other Current Liabilities | (23,469) | (28,251) | (23,002) | (50,883) |
| Total Current and Accrued Liabilities | 7,184,284 | 6,042,324 | 4,009,490 | 3,270,104 |
| Deferred Credits | | | | |
| Other Deferred Credits | 164,448 | 173,565 | 182,682 | 185,081 |
| Other Regulatory Liabilities | 3,616 | (3,467) | (13,296) | (8,620) |
| Accumulated Deferred Income Taxes - Other Property | 1,671,885 | 1,766,758 | 1,519,316 | 1,254,742 |
| Accumulated Deferred Income Taxes - Other | 1,978,292 | 1,426,159 | 1,296,486 | 1,326,401 |
| Total Deferred Credits | 3,818,241 | 3,363,015 | 2,985,188 | 2,757,604 |
| Total Liabilities and Equity | $ 48,243,515 | $ 41,197,426 | $ 36,311,471 | $ 32,612,521 |

**Pike County Light and Power Company, Inc.**

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Responses to Data Requests Under Section 53.53

| | September 30 2024 | September 30 2023 | September 30 2022 | September 30 2021 |
|---|---|---|---|---|
| **Operating Revenues:** | | | | |
| Residential Sales | $ 6,139,418 | $ 6,390,043 | $ 6,252,990 | $ 4,136,041 |
| Commercial & Industrial Sales | 7,039,827 | 7,445,456 | 7,024,559 | 3,900,393 |
| Public Lighting Sales | 211,526 | 203,981 | 176,996 | 132,405 |
| Total Sales and Delivery of Electricity | 13,390,772 | 14,039,480 | 13,454,545 | 8,168,839 |
| | | | | |
| Other Operating Revenues: | | | | |
| Miscellaneous Service Revenues | 28,184 | (2) | 12,975 | (2) |
| Rent from Electric Property | (57,902) | 335,040 | - | 168,517 |
| Other Electric Revenues | 2,976 | - | (58,606) | 36,767 |
| Total Other Electric Revenues | (26,742) | 335,038 | (45,631) | 205,282 |
| | | | | |
| Total Electric Operating Revenues | 13,364,029 | 14,374,517 | 13,408,914 | 8,374,121 |
| | | | | |
| Operating Expenses: | | | | |
| Purchased Electric Power Costs | 5,187,864 | 6,532,751 | 6,277,549 | 2,657,032 |
| Other Power Supply Expenses | 734,868 | 699,876 | 666,540 | 714,324 |
| Distribution Expenses | 773,828 | 521,681 | 290,732 | 471,189 |
| Customer Accounts Expenses | 311,292 | 178,164 | 331,356 | 283,560 |
| Customer Service Expenses | 30,590 | 31,651 | 42,795 | 37,736 |
| Administrative And General Expenses | 2,148,999 | 2,021,843 | 1,949,104 | 1,731,560 |
| Depreciation Expense | 1,096,950 | 801,133 | 755,885 | 828,687 |
| Taxes, Other than Income Tax | 560,165 | 915,526 | 959,260 | 530,912 |
| State Income Taxes | (1,319) | 103,014 | (373,914) | 58,650 |
| Federal Income Taxes | 358,680 | 354,714 | 325,689 | 126,208 |
| Total Operating Expense | 11,201,917 | 12,160,353 | 11,224,995 | 7,439,857 |
| | | | | |
| Total Income from Electric Utility Operations | 2,162,112 | 2,214,165 | 2,183,919 | 934,264 |
| | | | | |
| Taxes - Other Deductions: | | | | |
| Donations | 2,175 | 3,251 | 1,544 | 425 |
| Other Income Deductions | (90,023) | (18,706) | 17,623 | (98,997) |
| Total Taxes - Other Income Deductions | (87,848) | (15,454) | 19,167 | (98,572) |
| | | | | |
| Interest Charges: | | | | |
| Interest on Long Term Debt | 940,571 | 769,600 | 570,313 | 516,926 |
| Amortization of Debt Discount & Expense | 13,644 | 10,538 | 10,033 | 15,887 |
| Other Interest Expense | 28,006 | 94,201 | 9,187 | 10,244 |
| Total Interest Charges | 982,221 | 874,340 | 589,533 | 543,056 |
| | | | | |
| Net Income - Electric Operations | $ 1,267,740 | $ 1,355,280 | $ 1,575,218 | $ 489,779 |

**Pike County Light and Power Company, Inc.**

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| Electric Plant in Service | FERC Account | As of September 30, 2024 | 2023 | 2022 | 2021 |
|---|---|---|---|---|---|
| Distribution Plant | | | | | |
| Land and Land Rights | 360 | 1,090,953 | 1,090,953 | 1,090,953 | 1,090,953 |
| Structures and Improvements | 361 | (2,832) | - | - | - |
| Station Equipment | 362 | 1,272,591 | 1,239,496 | 1,239,496 | 1,211,517 |
| Poles, Towers, and Fixtures | 364 | 13,037,686 | 9,013,320 | 7,829,715 | 7,049,024 |
| Overhead Conductors and Devices | 365 | 7,090,175 | 5,693,773 | 4,895,508 | 4,667,901 |
| Underground Conduit | 366 | 299,714 | 160,142 | 121,032 | 121,032 |
| Underground Conductors and Devices | 367 | 656,996 | 655,598 | 554,820 | 448,306 |
| Line Transformers | 368 | 4,619,252 | 2,792,874 | 2,337,688 | 1,814,799 |
| Services | 369 | 2,444,132 | 2,345,622 | 2,329,466 | 2,091,680 |
| Meters | 370 | 956,931 | 722,330 | 722,330 | 587,411 |
| Street Lighting & Signal Systems | 373 | 735,150 | 341,717 | 341,717 | 145,670 |
| Total Distribution Plant | | 32,200,747 | 24,055,823 | 21,462,725 | 19,228,291 |
| | | | | | |
| General Plant | | | | | |
| Structures and Improvements | 390 | 2,339,399 | 2,087,743 | 2,087,743 | 2,029,447 |
| Small Tools | 394 | 365,052 | 236,212 | 236,212 | 123,052 |
| Total General Plant | | 2,704,451 | 2,323,955 | 2,323,955 | 2,152,499 |
| | | | | | |
| Electric Excess Reserve | 399 | (168,000) | (184,000) | (200,000) | (216,000) |
| | | | | | |
| Total Electric Plant-in-Service | | $ 34,737,197 | $ 26,195,778 | $ 23,586,680 | $ 21,164,789 |
| | | | | | |
| **Gas Plant in Service** | | | | | |
| Distribution Plant | | | | | |
| Land and Land Rights | 374 | $ 744 | $ 744 | $ 744 | $ 744 |
| Mains | 376 | 4,353,729 | 3,889,071 | 2,539,899 | 1,855,721 |
| Meas. And Reg. Equip. - General | 378 | 131,501 | 119,458 | 119,458 | 105,406 |
| Services | 380 | 1,693,812 | 1,446,545 | 1,312,073 | 760,861 |
| Meters | 381 | 62,823 | 72,166 | 72,166 | 72,166 |
| Meter Installations | 382 | 536,759 | 509,026 | 470,002 | 219,555 |
| House Regulator Installations | 384 | 9,539 | 9,539 | 9,539 | 9,539 |
| Industrial Measuring and Regulating Equipment | 385 | 36,151 | 32,861 | 32,861 | 32,861 |
| Total Gas Plant | | 6,825,059 | 6,079,412 | 4,556,744 | 3,056,854 |
| | | | | | |
| General Plant | | | | | |
| Small Tools | 394 | 346,404 | 79,638 | 79,638 | 35,805 |
| Total General Plant | | 346,404 | 79,638 | 79,638 | 35,805 |
| | | | | | |
| Gas Excess Reserve | 399 | 22,050 | 22,950 | 23,850 | 24,750 |
| | | | | | |
| Total Gas Plant-in-Service | | $ 7,193,512 | $ 6,182,000 | $ 4,660,232 | $ 3,117,410 |
| | | | | | |
| **Common Plant in Service** | | | | | |
| Intangible Plant | | | | | |
| Franchise Trade Name | 303 | $ 311,000 | $ 311,000 | $ 311,000 | $ 311,000 |
| Total Intangible Plant | | 311,000 | 311,000 | 311,000 | 311,000 |
| | | | | | |
| General Equipment | | | | | |
| Office Furniture & Equipment | 391 | 399,087 | 1,052,517 | 1,052,517 | 1,241,504 |
| Transportation Equipment | 392 | 596,946 | 189,895 | 189,895 | 228,126 |
| Communication Equipment | 397 | 143,360 | 143,360 | 143,360 | 139,262 |
| Misc Equipment | 398 | 13,477 | 3,550 | 3,550 | 90,340 |
| Total Common Plant | | 1,152,869 | 1,389,322 | 1,389,322 | 1,699,233 |
| | | | | | |
| Retirement Work in Progress | | | | | |
| | | | | | |
| Total Common Plant-in-Service | | $ 1,463,869 | $ 1,700,322 | $ 1,700,322 | $ 2,010,233 |

**Pike County Light and Power Company, Inc.**

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Responses to Data Requests Under Section 53.53

| | FERC Account | As of September 30, 2024 | 2023 | 2022 | 2021 |
|---|---|---|---|---|---|
| **Electric Depreciation Reserve** | | | | | |
| Distribution Plant | | | | | |
| Land and Land Rights | 360 | - | - | - | - |
| Structures and Improvements | 361 | 10 | 10 | 10 | 10 |
| Station Equipment | 362 | 246,881 | 213,412 | 182,449 | 151,860 |
| Poles, Towers, and Fixtures | 364 | 1,293,534 | 982,603 | 763,885 | 577,307 |
| Overhead Conductors and Devices | 365 | 869,846 | 723,501 | 595,014 | 485,102 |
| Underground Conduit | 366 | 17,913 | 13,740 | 10,782 | 8,910 |
| Underground Conductors and Devices | 367 | 82,797 | 69,396 | 52,692 | 43,887 |
| Line Transformers | 368 | 499,340 | 396,584 | 311,341 | 243,054 |
| Services | 369 | 295,671 | 208,610 | 161,862 | 117,506 |
| Meters | 370 | 261,696 | 195,405 | 156,756 | 131,438 |
| Street Lighting & Signal Systems | 373 | 57,174 | 33,350 | 17,614 | 12,719 |
| Total Distribution Plant | | 3,624,862 | 2,836,611 | 2,252,405 | 1,771,794 |
| General Plant | | | | | |
| Structures and Improvements | 390 | 387,796 | 330,671 | 1,840 | 119,121 |
| Small Tools | 394 | 235,043 | 235,043 | 170,558 | 66,879 |
| Total General Plant | | 622,839 | 565,713 | 172,397 | 186,001 |
| Electric Excess Reserve | 399 | | | | |
| Total Electric Plant-in-Service | | $ 4,247,701 | $ 3,402,324 | $ 2,424,802 | $ 1,957,795 |
| **Gas Depreciation Reserve** | | | | | |
| Distribution Plant | | | | | |
| Land and Land Rights | 374 | $ - | $ - | $ - | $ - |
| Mains | 376 | 249,602 | 195,824 | 147,971 | 120,601 |
| Meas. And Reg. Equip. - General | 378 | 30,369 | 23,748 | 19,770 | 15,877 |
| Services | 380 | 119,902 | 96,868 | 76,584 | 59,720 |
| Meters | 381 | 13,215 | 9,718 | 8,360 | 7,048 |
| Meter Installations | 382 | 52,697 | 38,343 | 27,924 | 18,510 |
| House Regulator Installations | 384 | 1,662 | 1,451 | 1,240 | 1,036 |
| Industrial Measuring and Regulating Equipment | 385 | 7,482 | 6,542 | 5,604 | 4,683 |
| Total Gas Plant | | 474,930 | 372,493 | 287,454 | 227,474 |
| General Plant | | | | | |
| Small Tools | 394 | 94,753 | 45,845 | 31,539 | 16,223 |
| Total General Plant | | 94,753 | 45,845 | 31,539 | 16,223 |
| Gas Excess Reserve | 399 | | | | |
| Total Gas Plant-in-Service | | $ 569,683 | $ 418,338 | $ 318,992 | $ 243,697 |
| **Common Depreciation Reserve** | | | | | |
| Intangible Plant | | | | | |
| Franchise Trade Name | 303 | $ 167,595 | $ 146,861 | $ 126,128 | $ 105,395 |
| Total Intangible Plant | | 167,595 | 146,861 | 126,128 | 105,395 |
| General Equipment | | | | | |
| Office Furniture & Equipment | 391 | 802,426 | 608,452 | 773,017 | 736,919 |
| Transportation Equipment | 392 | 252,900 | 144,026 | 112,099 | 180,591 |
| Communication Equipment | 397 | 139,877 | 139,877 | 138,612 | 126,775 |
| Misc Equipment | 398 | 40,093 | 37,256 | 36,546 | 123,538 |
| Total Common Plant | | 1,235,296 | 929,610 | 1,060,273 | 1,167,823 |
| Retirement Work in Progress | | | | | |
| Total Common Plant-in-Service | | $ 1,402,891 | $ 1,076,471 | $ 1,186,401 | $ 1,273,217 |

**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: January 14, 2025

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

| | | |
|---|---|---|
| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company – Electric Division | : | |

**STATEMENT NO. 1-R**

**REBUTTAL TESTIMONY OF**

**PAUL M. NORMAND**

**ON BEHALF OF**

**PIKE COUNTY LIGHT & POWER COMPANY**

Date: May 1, 2025

**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 OCA Witness Karl Pavlovic with respect to the Company's minimum distribution system results and customer charges, I&E Witness Esyan A. Sakaya's claim that the Company did not provide a breakdown of customer costs, and OSBA Witness Mark D. Ewen's discussion of revenue allocation, gradualism, and SC-2S rate design. 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 AN ELECTRIC 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 Paul Normand's Electric direct testimony on pages 6 through 15. Detailed COS results were provided with the Company's base rate filing as Exhibits E-6 through E-7. 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 DISCUSS THE UNDERLYING PURPOSE OF AN EMBEDDED COST OF SERVICE STUDY AS IS RELATES TO THE ASSUMPTIONS MADE BY OTHER PARTIES?**

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, 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 resulting in poor customer cost recovery 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 and identifiable component of 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 class revenues rate design proposals.

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

A. A customer component minimum system approach was introduced 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 smaller sized secondary lines are closer to customers and influenced considerably by population density and geography as opposed to the larger primary lines. Primary circuits consist of both three phase and single phase facilities. A large portion of primary is single phase and many of the SC2 customers that are three-phase cannot be served by single phase facilities. The miles and cost breakdown to implement this separation was not available which results in an over allocation of single phase to three phase customers. Adjusting for this overallocation would shift considerable cost assignments away from larger customers to lower-use customers.

**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, I did. A detailed summary of all these cost categories has been provided in Exhibit E-6, Schedule PMN-5-E, pages 3 and 4 at the claimed rate of return requested of 8.37%. The revenue requirements associated with each cost category are fully shown on page 3, lines 16 through 24 for the customer related cost items.

**Q. PLEASE DISCUSS THE COMPANY'S TWO DISTINCT AREAS OF FIXED CUSTOMER COST INVESTMENT IN ORDER TO PROVIDE ELECTRIC SERVICE TO ITS CUSTOMERS.**

A. The first area of fixed customer costs represents meters and services connecting customers to the Company's electric grid. These are the most basic costs which are closest to the customer and must be completely recovered on a monthly per-customer basis in order to not introduce any cross subsidies within a class of customers as currently exists.

The second area of fixed customer costs is local facilities (secondary circuits and secondary transformers) which also represent investment costs made by the Company to connect new customers to its distribution electric grid by using primary to secondary voltage transformers to convert primary voltage energy to a lower voltage for use by all secondary customers. In some instances, an additional cost may be required in secondary (conductor) circuits to connect this transformed energy to customers (reference pages 11 and 12 of Paul Normand's Electric direct testimony) which may be one or two pole lengths removed from the secondary voltage transformers. Based on class demand approaches, these added local facilities are also in very close proximity to each customer and have little diversity impact but are required to provide electric service to some customers. These local facility costs are fixed costs which are best recovered on a fixed monthly charge if we are to not introduce any additional cross subsidy.

Other parties have assumed that these local facilities already exist (which is very misleading) but achieves a desired end result which is to lower customer fixed cost recovery while increasing the volumetric (kWh) price.

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

A. The following table presents the results as found in Exhibit E-6, Schedule PMN-5-E, page 4, lines 37 and 48 (2) and Exhibit E-8, pages 3 and 4 (1):

Table ER1

Cost of Service Results – Claimed ROR

| | Existing Monthly Charge (1) | COS Local Facilities Meters, Services Cost (2) | COS Total Customer Costs (2) | Proposed Monthly Charge (1) |
|---|---|---|---|---|
| SC1 Residential (SC1) | 8.80 | 35.76 | 60.98 | 10.80 |
| SC1 Resid Space/Water Heating | 8.80 | 36.94 | 62.27 | 10.80 |
| SC2-S Small C&I Secondary | 17.26 | 57.64 | 82.53 | 21.50 |
| SC2-P Small C&I Primary | 140.00 | 80.93 | 132.09 | 175.00 |

Note: Local facilities represent secondary circuits from plant accounts 364 and 365 along with account 369 secondary line transformers (reference pages 11 and 12 of Paul Normand's direct testimony).

**Q. COULD YOU COMMENT ON THESE MONTHLY CUSTOMER CHARGES?**

A. Yes. As can be noted from the above Table 1 customer cost results, the existing and proposed customer charges for the smaller customers recover only a small portion of the costs of connecting these customers to the electric grid with the remaining costs recovered by the remaining customers in the class on a kWh basis. The effect is a poor cost recovery which is further amplified by the kWh recovery of all demand costs.

**Q. WHY IS IT IMPORTANT TO COMPARE THE PROPOSED MONTHLY CUSTOMER CHARGE TO THE COST OF METERS, SERVICES AND LOCAL FACILITIES?**

A. The important issue here is to recognize that each customer needs a meter and a service in order to receive electric service from the company's grid. This is simply a basic need of service where the dedicated meter and service cannot be utilized by anyone else. Also, as I mentioned above, the local facilities (secondary circuits and secondary voltage transformers) investment along with the service and the meter represents the fixed customer investment shown in Table 1 and are much higher than the existing and proposed monthly customer cost. Our proposed levels are therefore entirely justified and the unrecovered fixed cost balance being recovered incorrectly through volumetric charges and, in most cases, recovered by other large energy users in the class who cannot access these meters, services, line transformers and secondary circuits 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 being provided, the demographics of its customers, the design of the distribution facilities and guidance from the regulatory commission concerning class revenue targets and 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.

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

OCA Witness - Karl Richard Pavlovic

**Q. DO YOU AGREE WITH WITNESS PAVLOVIC'S DISCUSSION WITH RESPECT TO THE ASSUMPTION THAT CLASSIFYING ANY PORTION OF FERC DISTRIBUTION ACCOUNTS 365-368 AS CUSTOMER RELATED CONTRAVENES THE PRINCIPLE OF COST CAUSATION (DIRECT TESTIMONY PAGE 8)?**

A. No, I do not. Our calculations are similar to the Company's last rate case where there was a limited level of minimum system developed for accounts 364-368. As the Distribution Factor table summarizes on page 12 of our pre-filed direct testimony (Statement 1) shows, there were no minimum systems developed for any primary voltage costs. This is correct as the primary voltage system consists of both single and three phase facilities. The only minimum system considered was with respect to the lower transformed secondary network (low voltage) served from primary circuits.

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

A. No, I do not. As I presented earlier in this rebuttal (Table 1), the existing and proposed customer charges are a small fraction of the actual local facilities, service, and metering costs to connect the customer to the electric grid. Maintaining and supporting lower monthly customer charges simply encourages subsidies and uneconomic pricing resulting from just kWh pricing.

**Q. DO YOU AGREE WITH WITNESS PAVLOVIC'S RECALCULATION OF THE ELECTRIC COS TO RECLASSIFY THE CUSTOMER RELATED COSTS FOR ACCOUNTS 364-368 AS DEMAND?**

A. No, I do not. A brief review of the customer allocated costs can be found on Exhibit E-6, Schedule PMN-4-E, page 3 of 27. Here you will note the customer component for accounts 364-368 is $10,372,792 of the total distribution costs of $32,200,747 or 32.2%. The reason that this number is low stems from the fact that classified primary costs are allocated 100% on class demands and have no customer component as we emphasized local facilities as the driver of customer costs.

I&E Witness - Esyan A. Sakaya

**Q. DO YOU AGREE WITH WITNESS SAKAYA'S CHARACTERIZATION OF THE COMPANY'S CUSTOMER COSTS CALCULATIONS NOT BEING CLEAR AS TO WHAT IS OR IS NOT INCLUDED?**

A. No, I do not. The Excel version of the cost of service study (COSS), Exhibit E-6, Schedule PMN-5-E, was provided in data response OSBA-1-2. This COSS model includes a summary tab entitled "FUNCTIONS" which shows the detailed accounts and dollars in column H identified as "CUSTOMER". As we mentioned earlier, the proposed customer charges are a small portion of the total calculated customer costs.

**Q. DO YOU AGREE WITH WITNESS SAKAYA'S CHARACTERIZATION THAT "CUSTOMER DISTRIBUTION SECONDARY" ALSO REFERRED TO AS LOCAL FACILITIES (SECONDARY CIRCUITS AND SECONDARY LINE TRANSFORMERS) COSTS SHOULD NOT BE INCLUDED AS CUSTOMER COSTS (PAGE 28)?**

A. No, I do not. To be consistent with the overall planning process, customers are added to facilities by adding primary to secondary voltage transformers and a limited secondary circuit connecting some customers to the secondary transformers from distribution to serve a limited number of customers. The existing secondary infrastructure is generally limited and not so densely installed that customers are always added from existing facilities. In many locations, customers each have a transformer and no secondary. This assumption by witness Sakaya is completely inaccurate and reflects a lack of understanding of the installed facilities and their capability to recognize and accept new customers, especially local facilities. A simple review of plant growth in these accounts reflects added and improved facilities.

<u>OSBA Witness - Mark D. Ewen</u>

**Q. DO YOU AGREE WITH WITNESS EWEN'S PORTRAYAL OF THAT COMPANY'S REVENUE ALLOCATION IS OVERLY BIASED TOWARDS RATE GRADUALISM CONCERNS AT THE EXPENSE OF MAKING PROGRESS TOWARD COST-BASED RATES?**

A. No, I do not. Our rate design revenue allocation considered rate moderation to reflect the large increase (29.1% base).

**Q. DO YOU AGREE WITH WITNESS EWEN'S SC-2S PROPOSED CHANGES IN RATE DESIGN?**

A. No, I do not. Collapsing the rate blocks shifts costs to larger users when, in fact, the lower demand blocks are in sync with the larger first block of energy charge using the kWh hours use concept which provides a unique rate for each customer based on their consumption characteristics and reflects an excellent costs recovery approach.

**Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes, it does.

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

| | | |
|---|---|---|
| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company – Electric Division | : | |

**Statement No. 2R**
**Rebuttal Testimony of**
**Accounting Panel**
**Charles Lenns and Matthew Lenns**

Date: May 1, 2025

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**PAGE**

**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. We also discussed the adjustments made to the Historic Test Year in order to calculate the requested rate increase.

## 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.
- Adopt as part of the Company's Update, in whole or in part, certain adjustments proposed by the Bureau of Investigation and Enforcement's ("I&E") witness Getachew Bedasa (I&E Statement 1) and by the Office of Consumer Advocate's ("OCA") witness Jennifer L. Rogers (OCA Statement 1).
- Address and rebut adjustments proposed by I&E witnesses Getachew Bedasa (I&E Statement No. 1) and Esyan A. Sakaya (I&E Statement No. 3) as well as OCA witness Jennifer L. Rogers (OCA Statement No. 1) that the Company does not believe are appropriate.

- Discuss the Capital Structure and interest rate recommendations of I&E witness D.C. Patel (I&E Statement No. 2) and OCA witness Maureen L. Reno (OCA Statement No. 2).

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

A. Yes. Based on updates we will be discussing in the following portion of our testimony, the Company has lowered its requested revenue increase by $217,800 to $1,656,800.

**UPDATES – RATE BASE**

**Plant, Accumulated Depreciation, and Accumulated Deferred Income Taxes:**

**Q. PLEASE DISCUSS THE RATE BASE ADJUSTMENTS PROPOSED BY I&E WITNESS ESYAN A. SAKAYA (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 Esyan A. Sakaya (I&E Statement No. 3, pages 5 - 13) and OCA witness Jennifer L. Rogers (OCA Statement No. 1, pages 6-7) recommended eliminating all requested electric 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 Esyan A. Sakaya decreased electric utility plant by $2,300,000 along with $125,000 of projected retirements (I&E Statement 3, page 7, lines 8-11) for a net amount of $2,175,000 ($2,300,000 - $125,000). He also made an adjustment to reduce common utility plant allocated to electric by $170,000 along with $42,500 of projected retirements for a net of $127,500 ($170,000- $42,500), (I&E Statement 3, page 10, lines 6-19).

OCA witness Jennifer L. Rogers reflected an adjustment to reduce both Post Future Test Year electric plant and common plant allocated to electric by $2,302,500 (OCA Statement No. 1, page 7, lines 6 -10). Her one adjustment is equivalent to Mr. Sakaya's two separate adjustments ($2,175,000 + $127,500}.

**Q. HOW MANY ADJUSTMENTS WERE MADE TO THE ACCUMULATED DEPRECIATION RESERVE THAT WERE RELATED TO THE TEST YEAR PLANT ADDITIONS?**

A. I&E witness Esyan A. Sakaya decreased the electric accumulated depreciation reserve by a net of $447,200 (I&E Statement 3, page 8, lines 9-12). He also made an adjustment to reduce the common accumulated depreciation reserve allocated to electric by a net of $79,050 (I&E Statement 3, page 12, lines 12-17).

OCA witness Jennifer L. Rogers reflected an adjustment to reduce both Post Future Test Year electric and common accumulated depreciation reserves allocated to electric by $526,250 (OCA Statement No. 1, page 7, lines 22-23). Her one adjustment is equivalent to Esyan A. Sakaya's two separate adjustments ($447,200 + $79,050).

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

A. I&E witness Getachew Bedasa (I&E Statement No. 1, page 31, line 4-6) and OCA witness Jennifer L. Rogers (OCA Statement No. 1, pages 8, lines 4-11) recommended decreasing Accumulated Deferred Income Taxes by $23,700. Their proposed adjustment represents a partial offset to the decrease in Post Future Test Year Plant Additions discussed previously.

**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 $1,752,550 ($2,302,500 - $526,260 - $23,700), which lowered the revenue requirement by $191,000 ($250,900 – 57,400 – 2,500).

**<u>Cash Working Capital – Lead Lag Study</u>**

**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 $170,000 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 85% in the calculation. The offset is in the other O&M category. As a result of these adjustments, electric O&M decreased by $177,800 and the cash working capital requirement increased by $16,700, which produced a $2,100 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 electric working capital requirements.

**Regulatory Assets – Deferred Storm Costs**

**Q. DID I&E WITNESS GETACHEW BEDASA AND OCA WITNESS JENNIFER L. ROGERS PROPOSE AN ADJUSTMENT TO DEFERRED DEBITS RELATED TO DEFERRED STORM CHARGES?**

A. Yes. Both I&E witness Getachew Bedasa and OCA witness Jennifer L. Rogers made an adjustment to remove deferred Riley Storm costs from Rate Base. The Company agrees with this adjustment and has eliminated the net deferred balance from Rate Base as part of this Update. As shown on the Revenue Requirement Update table below, Rate Base was reduced by $109,660, which lowers the electric revenue requirement by $13,400.

**Deferred Debits – Rate Case Costs**

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

A. Yes. Both I&E witness Getachew Bedasa and OCA witness Jennifer L. Rogers made an adjustment to remove Rate Case costs 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 on the Revenue Requirement Update table below, Rate Base was reduced by $192,440, which lowered the electric revenue requirement by $23,600.

**Deferred TCJA Credits**

**Q. I&E WITNESS GETACHEW BEDASA 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 added the Accumulated TCJA Deferred Tax Benefits to Rate Base, rather than subtracting them. In addition, the amounts reflected by the Company were stated "net of tax." I&E witness Getachew Bedasa's adjustment properly reflects the gross amount of the Accumulated TCJA Deferred Taxes in Rate Base. As shown on the Revenue Requirement Update table below, Rate Base was reduced by $218,400, which lowers the revenue requirement by $26,800. 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.

**Intercompany M&T charges**

**Q., PLEASE DISCUSS YOUR UPDATE FOR INTERCOMPANY CHARGES SHOWN IN THE ACCOUNTING PANEL'S STATEMENT NO. 2 EXHIBIT E-4, SCHEDULE 10?**

A. Exhibit E-4, Schedule 10 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 reduced intercompany expense by $170,000 ($200,000 x 85%) in order to eliminate the electric portion of this out of period charge. The second adjustment removed 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 $177,800 ($170,000 + $7,800). As shown on the Revenue Requirement Update table below, the adjustments for intercompany charges lowered the electric revenue requirement by $189,600 ($181,200 + $8,400).

**Q. DID I&E WITNESS GETACHEW BEDASA AND OCA WITNESS JENNIFER L. ROGERS PROPOSE A SIMILAR ADJUSTMENT?**

A Yes. Both I&E witness Getachew Bedasa (I&E Statement 1, page 20, lines 15-20 and page 21, lines 1-2) and OCA witness Jennifer L. Rogers made adjustments to eliminate the electric portion of the out of period charge and the Company’s escalation adjustment.

**<u>Minor Storm Costs (Eliminate from Hurricane Riley Amortization)</u>**

**Q., PLEASE DISCUSS YOUR UPDATE TO THE ACCOUNTING PANEL'S STATEMENT 2, EXHIBIT E-4, SCHEDULE 7?**

A. Exhibit E-4, Schedule 7 shows the current and forecasted amortization of historic Hurricane Riley costs. In addition, Minor Storm costs of $150,000 were included in this Schedule. The minor storm cost should not have been included as part of this Schedule and combined with the amortization of historic costs. By including the minor storm cost of $150,000, the calculations in this Schedule also resulted in an additional amortization of $37,500 ($150,000 / 4 years) of minor storm costs. Removing the minor storm costs from Exhibit E-4, Schedule 7 lowered the associated Hurricane Riley adjustment by $187,500 ($150,000 + 37,500). As shown on the Revenue Requirement Update table below, the adjustments for minor storm charges lowered the revenue requirement by $199,700.

**Q. DID I&E WITNESS GETACHEW BEDASA AND OCA WITNESS JENNIFER L ROGERS PROPOSE A SIMILAR ADJUSTMENT?**

A Yes. I&E witness Bedasa also proposed eliminating the $150,000 minor storm cost (I&E Statement 1, page 22 lines 16-18 and page 23, lines 1-3). OCA witness Jennifer L. Rogers discussed this adjustment as part of OCA Statement 1, page 19, lines 15-22 and page 20, lines 1-2.

**<u>Depreciation Expense</u>**

**Q. DOES THE ACCOUNTING PANEL HAVE UPDATES FOR BOOK DEPRECIATION EXPENSE?**

A. Yes. In the Accounting Panel's Exhibit E-4, Schedule 12, Page 1 of 4, the forecast of plant retirements was inadvertently added rather than subtracted from net plant to develop the base upon which the composite book depreciation rates were applied to calculate the annual book depreciation expense. This resulted in overstatement of depreciation expense of $39,500 in the Future Test Year and $19,600 related to the Plant additions for the October 1, 2025 – March 31, 2026 time period for a total of $59,100.

**Q. DID OCA WITNESS JENNIFER L. ROGERS PROPOSE A SIMILAR ADJUSTMENT?**

A Yes. OCA Statement 1, page 11, lines 17-23 discusses the first adjustment of $39,500. The amount of $19,600 is embedded in her proposed adjustment to eliminate all plant additions between October 1, 2025 and March 31, 2026.

**Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT PROPOSED BY I&E WITNESS ESYAN A. SAKAYA (I&E STATEMENT 3) AND OCA WITNESS JENNIFER L. ROGERS (OCA STATEMENT 1) FOR POST FUTURE TEST YEAR PLANT.**

A. Consistent with their recommended adjustment to reduce the depreciation reserve for Post Future Test Year Plant, I&E witness Esyan A. Sakaya (I&E Statement No. 3, page 15, lines 6-7) reduced depreciation expense by $69,536 and OCA witness Jennifer L. Rogers (OCA Statement No. 1, pages 11, lines 10-16) recommended eliminating the associated book depreciation expense in the amount of $94,000. As discussed above, there was a correction of $19,600 that is included in OCA witness Jennifer L. Rogers Post Test Year depreciation adjustment. Eliminating this portion of her adjustment results in a net adjustment of $74,400 ($94,000 – $19,600). The difference between the adjustment proposed by I&E witness Esyan A. Sakaya and OCA witness Jennifer L. Rogers' net adjustment is $4,864 ($74,400 - $69,536). The variation was caused by the weighting of the composite depreciation rate in OCA's calculation for the future test year plant after correcting removal cost error in the Company's original depreciation calculation. I&E witness Esyan A. Sakaya relied on the Company's original composite depreciation rate. The Company believes Jennifer L. Rogers' adjustment is accurate.

**Q. HAS THE ACCOUNTING PANEL MADE THE ADJUSTMENTS DISCUSSED ABOVE TO CORRECT THE MANNER IN WHICH RETIREMENTS WERE REFLECTED IN THE DEPRECIATION CALCULATION AND TO ELIMINATE THE DEPRECIATION EXPENSE FOR POST FUTURE TEST PLANT ADDITIONS?**

A. Yes. The Accounting Panel has reflected two adjustments for depreciation expense. The first adjustment lowers depreciation expense by $59,100 ($39,500 + $19,600) to correct the depreciation calculation for retirements. The second adjustment eliminated the depreciation expense associated with Post Future Test Year Plant by $74,400 ($94,000 - 19,600). As shown on the Revenue Requirement Update table below, the adjustments for depreciation expense lowered the electric revenue requirement by $142,500 ($42,200 + $100,300).

**<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-4, SCHEDULE 14, PAGES 1 AND 3?**

A. Yes. In calculating the annual interest deduction shown on Exhibit E-4, Schedule 14, 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 electric revenue requirement.

**Q. WHAT IS 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 E-4, Schedule 14, page 3 lowers the electric Future Test Year interest deduction from $2,814,318 to $1,388,350 and the associated federal and state income taxes by $407,700. The electric revenue requirement impact of this change is approximately $597,800 ($407,700 x gross-up factor of 1.4664).

**Q. DID I&E WITNESS GETACHEW BEDASA AND OCA WITNESS JENNIFER L ROGERS RECOMMEND A SIMILAR CORRECTION?**

A Yes. On I&E Statement 1, page 35 and OCA Statement 1, page 23, lines 12-19, Getachew Bedasa and Jenifer L. Rogers, respectively, discuss the correction required in the income tax calculations to reflect the embedded cost of debt in the Company's income tax calculation rather than the "unweighted cost of debt" interest rate.

<u>**Deferred FIT Expense (TCJA Tax Benefits)**</u>

**Q. PREVIOUSLY YOU DISCUSSED AN ADJUSTMENT TO RATE BASE FOR THE TCJA DEFERRED TAX BENEFITS THAT WERE INADVERTENTLY ADDED TO RATE BASE RATHER THAN SUBTRACTED FROM RATE BASE. IS THERE AN ASSOCIATED INCOME TAX ADJUSTMENT THAT ALSO IS REQUIRED?**

A. Yes. The Company's income tax calculations included in our Exhibit E-4, Schedule 14, page 1, should have included a credit for the 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 lowers total electric income tax expense by $17,420, which reduces the revenue requirement by approximately $25,550 ($17,420 x the gross up factor of 1.4664). We are making one additional update for the residual balance in Company Account 186150 which has a credit balance of $15,153. We are proposing to amortize this credit amount over four years in the Company's Tax calculation in order to pass this credit back to customers. This adjustment reduces the electric revenue requirement by an additional $5,550 ($15,153 / 4 years x 1.4664).

**Q. DID I&E WITNESS GETACHEW BEDASA RECOMMEND A SIMILAR CORRECTION?**

A. Getachew Besa proposed the first adjustment discussed above (I&E Statement 1, page 29, lines 14-18). The second update will allow the Company to pass back the residual credit balance in Account 186150 over four years to customers.

**<u>Revenue Requirement</u>**

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

A. As shown on the Revenue Requirement Update table below, the updates and corrections to the revenue requirement would have the effect of decreasing the electric revenue requirement by $217,800, from $1,874,600 to $1,656,800.

**Pike AP-E Update Summary**

**Pike County Light & Power Company, Inc.**
Electric Rate Cast R-2024-3052359
Revenue Requirement Updates

| | April Update Adjustment | Rev. Reqm't Impact | |
|---|---|---|---|
| **Rate Increase (As Filed)** | | | $ 1,874,600 |
| | | | |
| **Operating Expenses** | | | |
| Intercompany M&T Charges | $ (170,000) | $ (181,200) | |
| Escalation of Interco Charges | (7,800) | (8,400) | |
| Minor Storm Expense | (187,500) | (199,700) | |
| | | | |
| **Depreciation Expense** | | | |
| Removal Cost Oct. 2024 - Sept 2025 | (39,500) | (42,200) | |
| Oct. 2025 - Sept 2026 | (94,000) | (100,300) | |
| | | | |
| **Income Tax Expense** | | | |
| Amort of Def TCJA Credits: | | | |
| Reflect current amort. in FIT calculation | (17,420) | (25,550) | |
| Reflect additional amort. in FIT calculation | (3,783) | (5,550) | |
| | | | |
| **Interest Synchronization** | | | |
| Corrected Embedded Cost of Debt | 407,700 | 597,800 | |
| | | | |
| **Rate Base** | | | |
| **Post Future Test Year** | | | |
| Plant Additions | (2,302,500) | (250,900) | |
| Depreciation Reserve | 526,250 | 57,400 | |
| Accumulated Deferred Income Taxes | 23,700 | 2,500 | |
| | | | |
| **Cash Working Capital** | | | |
| Intercompany M&T Charges | 16,700 | 2,100 | |
| | | | |
| **Deferred Debits** | | | |
| Eliminate Deferred Riley Charges | (109,660) | (13,400) | |
| Eliminated Deferred Rate Case Expense | (192,440) | (23,600) | |
| | | | |
| **Other Deferred Credits** | | | |
| Correct Accumulated Deferred TCJA Credits | (218,400) | (26,800) | |
| | | | |
| **Total Update Adjustments** | | | (217,800) |
| | | | |
| **Revenue Requirement with Update Adjustments** | | | **$ 1,656,800** |

## REBUTTAL OF ADJUSTMENTS PROPOSED BY PARTIES

### Rate Base

### Cash Working Capital

**Q. DOES THE COMPANY HAVE AN ISSUE REGARDING THE ADJUSTMENT TO THE WORKING CAPITAL ALLOWANCE PROPOSED BY I&E WITNESS GETACHEW BEDASA (I&E STATEMENT NO. 1, PAGE 33)?**

A. Yes. I&E witness Getachew Bedasa proposes to modify the Company's Lead Lag Study by removing uncollectable accounts expense. The adjustment would reduce the Company's Cash Working Capital requirement by $34,490. The justification he used for the adjustment is that customer bad debt costs represent a "non-cash" item and therefore do not belong in the lead-lag study.

**Q. DOES THE ACCOUNTING PANEL AGREE WITH I&E WITNESS GETACHEW BEDASA'S PROPOSED ADJUSTMENT?**

A. No. Customer bad debt expenses are an offset to customer billed revenues and are therefore real cash expenses. To the extent that all revenues are reflected in the lead-lag study, it is appropriate to reflect the impact of those revenues that will never be collected from customers. The Company's lead-lag study accounts for all revenues and expenses. Certain operating expenses are reflected with a "zero-lag" not because they are "non-cash" items but rather because they are reflected as other component parts of rate base (e.g., the working capital requirement for PUC Assessments, Gross Receipts and property taxes are included with prepaid balances).

**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.

**<u>Cost of Service</u>**

**<u>Normalization / Amortization Periods</u>**

**Q. WHAT AMORTIZATION PERIODS DID THE COMPANY AND I&E WITNESS GETACHEW BEDASA (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 and storm 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 Getachew Bedasa proposed a five-year period (sixty months) for rate case and storm costs.

**Q. DOES THE COMPANY'S ACCOUNTING PANEL AGREE THAT USING A FIVE-YEAR RECOVERY PERIOD FOR STORM AND RATE CASE COSTS IS APPROPRIATE?**

A. No. We do not agree that setting longer periods to recover deferred storm and rate case costs is appropriate. First, the Company has to absorb carrying costs for the unrecovered storm cost balances for a longer period of time. The Company has already been absorbing the carrying cost for deferred storm charges since March 2018. Based on a five-year recovery period, the Company would end financing the net deferred balance for almost thirteen years before all of the costs are fully recovered. The argument set forth by I&E witness Getachew Bedasa that historically the average period between the Company's last three base rate case filings was 66 months (I&E Statement No. 1, page 8, line 5) 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 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 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 PCLP's daily operations with that of its New York utility affiliate Corning Natural Gas Company, Inc. ("CNG").

Based on the forgoing, an amortization / normalization period of more than four years is unreasonable unless the Company is allowed carrying costs on the unrecovered balance of deferred costs.

**Q. DOES THE COMPANY AGREE WITH MR. BEDASA'S ARGUMENT THAT HISTORY IS A BETTER INDICATION OF HOW FREQUENTLY THE COMPANY WILL FILE FOR NEW RATES?**

A. No. PCLP anticipates that it will be filing more frequently than it has in the past. Delaying recovery of deferred costs will require the Company to file its next rate case sooner rather than later, since it will be required to absorb carry costs on deferred charges, instead of using those funds to support ongoing utility operations.

**<u>Deferral vs. Normalization of Rate Case Costs</u>**

**Q., PLEASE DISCUSS THE COMPANY'S REASONS FOR OPPOSING I&E WITNESS GETACHEW BEDASA'S 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 impact on the Company's earnings. In the historic Test Year, Pike had net income from both electric and gas operations of $1,292,367 (Statement No. 2, Exhibit E-1, Schedule 3). A charge to expense of $250,000 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>Payroll & Associated Benefit Expense (electric)</u>**

**Q. DID I&E WITNESS GETACHEW BEDASA PROPOSE ADJUSTMENTS TO REDUCE THE AMOUNT OF PAYROLL AND PAYROLL ANCILLARY COSTS CHARGED TO PIKE'S ELECTRIC OPERATIONS BY A TOTAL OF $14,380?**

A. Yes, witness Bedasa has proposed three adjustments to reduce the Company's payroll and the associated payroll ancillary costs by a total of $14,380 (I&E Statement No. 1, pages 13-19). The adjustments were based on his recommendation to disallow PCLP's allocated share of payroll cost associated with a new System Planner of $10,000 along with the related fringe benefit and payroll tax expense of $4,380 (i.e., $3,615 plus $765) due to the uncertainty as to when the System Planner position will be filled by the Company.

**Q. DOES THE COMPANY HAVE MORE UP-TO-DATE INFORMATION REGARDING WHEN THE NEW EMPLOYEE WILL BE HIRED?**

A. Yes. The Company has recently offered the System Planner position to a new candidate, who accepted the job offer and will begin employment with PCLP on May 12, 2025. As a result, the payroll adjustments proposed by I&E witness Bedasa should not be adopted.

**<u>Minor Storm Costs</u>**

**Q. DID I&E WITNESS GETACHEW BEDASA RECOMMEND AN ADJUSTMENT FOR STORM COSTS?**

A. Yes. I&E witness Getachew Bedasa proposed two adjustments for minor and major storm costs. As discussed previously, I&E witness Bedasa recommended that the amortization period for deferred major storm costs be increased from four years to five years, which we disagree with unless the Company receives carrying charges on the unamortized balance.

His second adjustment was to eliminate the Company's request to recover $150,000 per year as part of future estimated minor storm costs.

**Q. DOES THE COMPANY AGREE WITH MR. BEDASA'S ADJUSTMENT TO ELIMINATE $150,000 OF MINOR STORM COSTS FROM THE RECOVERY OF DEFERRED STORMS COSTS?**

A. The Accounting Panel agrees with Mr. Bedasa that the minor storm costs should not have been included with the amortization of deferred major storm (Riley) costs. It represents a request to establish a rate allowance that would allow the Company to recover costs associated with minor storm damage which can vary significantly from year to year. We addressed the minor storm expense in our updated testimony and in the following section we will discuss the adjustment to minor storm expense proposed by OCA witness Jennifer L. Rogers.

**Q. WHAT ADJUSTMENTS TO MINOR STORM EXPENSE DID OCA WITNESS JENNIFER L. ROGERS RECOMMEND TO MINOR STORM EXPENSE?**

A. OCA witness Rogers has proposed two adjustments to minor storm expense. First, she calculated a three-year average of historic minor storm expense of $68,562 and compared the level of minor storm expense in the Historic Test Year of $146,866 to "normalize" or reduce the historic level by $78,304 ($146,866 - $68,562). She made a second adjustment to eliminate the Company's request for additional funding for minor storms included in the storm amortization calculation of $187,512. The total amount of her two adjustments was $265,816 (i.e., $78,304 plus $187,512).

**Q. DOES THE ACCOUNTING PANEL AGREE WITH BOTH OF OCA WITNESS ROGERS' ADJUSTMENTS?**

A. The Accounting Panel agrees that inclusion of the minor storm expense in the amortization of historic storm cost was an error and an adjustment to eliminate this cost from that schedule of $187,500 is appropriate. The Accounting Panel does not, however, agree with OCA witness Jessica L. Rogers' adjustment to reduce annual minor storm expense in the Historic Test Year from $146,866 to $68,562. OCA witness Jennifer L. Rogers did not have complete data upon which to base her proposed adjustment. The Company began tracking minor storm expense in calendar year 2023, so the fiscal year ending September 30, 2023 did not have a full year's worth of minor storm expense data. The twelve months ended September 30, 2022 showed that nothing was spent for minor storm cost, which is clearly an error. The Company believes the level of minor storm costs of $146,866 incurred during the twelve months ending September 30, 2024 represents a normal level of minor storm costs and was the basis for its request of $150,000. While no one can predict the frequency and extent of storm damage that will occur in any particular year, few would argue that there has been an increase in the incidence of storm activity due to climate change over the last few years. Exhibit AP-E Customer Interruptions below shows the number of outage hours for the twelve months ending September 30, 2022, 2023, and 2024. The overall number of outages for each fiscal year do not vary significantly, averaging 241 per year over the three-year period from October 1, 2021 – September 30, 2024. Accordingly, Exhibit AP-E Customer Interruptions shown below provides a reliable indication of the level of costs to be incurred in each year to restore power to customers.

The Accounting Panel recommends that the Commission reject OCA witness Rogers' adjustment to reduce the Historic Test Year minor storm costs by $78,304.

| | | | | | |
|---|---|---|---|---|---|
| | | | **Pike AP-E Customer Interruptions** | | |
| **Pike County Light & Power Company, Inc.** | | | | | |
| Electric Rate Cast R-2024-3052359 | | | | | |
| Customer Interruptions - Rolling 12-Month Period | | | | | |
| **Year** | **Quarter** | **Average Customers Served** | **Number of Interruptions** | **Customers Affected** | **Customer Minutes of Interruptions** |
| 2021 | 4th Qtr. | 4,891 | 66 | 6,890 | 1,058,853 |
| 2022 | 1st Qtr. | 4,924 | 63 | 6,696 | 1,059,038 |
| 2022 | 2nd Qtr. | 5,121 | 62 | 5,256 | 961,247 |
| 2022 | 3rd Qtr. | 5,167 | 72 | 3,211 | 439,053 |
| 2022 | 4th Qtr. | 5,299 | 63 | 2,646 | 420,975 |
| 2023 | 1st Qtr. | 5,302 | 65 | 2,663 | 427,484 |
| 2023 | 2nd Qtr. | 5,305 | 59 | 2,340 | 418,484 |
| 2023 | 3rd Qtr. | 5,305 | 53 | 2,952 | 303,163 |
| 2023 | 4th Qtr. | 5,314 | 49 | 3,344 | 289,297 |
| 2024 | 1st Qtr. | 5,334 | 54 | 5,029 | 525,476 |
| 2024 | 2nd Qtr. | 5,342 | 61 | 4,526 | 534,971 |
| 2024 | 3rd Qtr. | 5,348 | 57 | 4,080 | 620,301 |
| Oct, 2021 - Sept.2022 | | 5,026 | 263 | 22,053 | 3,518,191 |
| Oct, 2021 - Sept.2023 | | 5,303 | 240 | 10,601 | 1,570,106 |
| Oct, 2021 - Sept.2023 | | 5,335 | 221 | 16,979 | 1,970,045 |
| Average (Oct. 2021 - Sept. 2024 | | **5,221** | **241** | **16,544** | **2,352,781** |

**Informational Advertising**

**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 THAT PROPOSED 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 THAT 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 not 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 the parent company utilized 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, PCLP believed that having one of the "Big Four" firms as its auditor was beneficial 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 ELECTRIC PORTION $1,360 ($1,600 X 85%) 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 service outages. 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 annual dinner is part of its outreach efforts with the local community and is primarily done to benefit customers. As a result, the Accounting Panel recommends that the Commission reject OCA witness Jennifer L. Rogers' adjustment that would eliminate the electric portion of the Pike Community Foundation Annual Dinner expense.

**<u>Capital Structure</u>**

**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 53-63 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 40.81% LONG-TERM DEBT, 8.66% SHORT-TERM DEBT, AND 50.52% COMMON EQUITY. DID EITHER I&E WITNESS D.C. PATEL OR OCA WITNESS MAUREEN L. RENO RECOMMEND A DIFFERENT CAPITAL STRUCTURE FOR THE COMPANY IN THIS CASE?**

A. No. D.C. Patel (I&E Statement 2, page 8, lines 18–22) indicated that a "capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility as well as trying to control costs to ratepayers in this proceeding."

OCA witness Maureen L. Reno (OCA Statement No. 2, page 24, lines 17-18) indicated "Pike's proposed equity ratio of 50.52%, 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 50.52% EQUITY RATIO?**

A. Yes. OCA witness Maureen L. Reno (OCA Statement 2, page 25, lines 1 – 12) indicated that the Company equity ratio of 50.52% should be established as a maximum. While she stated that the proposed equity ratio of 50.52% falls within the range of annual average equity ratios approved by regulatory commissions for regulated electric utilities since 2020, she indicated that Pike's proposed equity ratio of 50.52% 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 50.52% EQUITY RATIO?**

A. No. The Accounting Panel does not agree that its equity ratio should capped at 50.52%. 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. D.C. Patel (I&E Statement 2, page 10, lines 13) accepted the Company's short-term interest rate, while OCA witness Maureen L. Reno (OCA Statement No. 2, page 29, lines 5-10) 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 credit ratings. Companies with higher credit ratings generally pay an amount equal to, or less than, the Prime Interest Rate and those with a lower credit rating 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. WITH REGARD TO 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 LONG-TERM INTEREST?**

A. D.C. Patel (I&E Statement 2, page 8, lines 1–21) accepted 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 million at a coupon rate of 6.31%, plus the unamortized debt issuance expenses to arrive at 6.80%.

Maureen L. Reno (OCA Statement No. 2, page 27, lines 13-14) 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 28, 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. PCLP 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 on a stand-alone basis, since it was acquired by Corning Energy Corporation, due to its small size, it was, and it still is, on a stand-alone basis unable to refinance its corporate debt. Further, prior to its acquisition by Argo in 2022, PCLP, Corning Energy Corporation ("CEC") and all of its other subsidiaries, were unable to refinance its 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 is 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 in 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 as being without any basis in fact.

**Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes, it does.

# APPENDIX

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | **Pike AP-E Update** |
| | | | | | | **Schedule 1** |
| | | | | | | |
| | | | **Pike County Light & Power Company, Inc.** | | | |
| | | | Electric Rate Cast R-2024-3052359 | | | |
| | | | Summary of Revenue Requirement Updates | | | |
| | 12 mos. Ended September 30, 2025 As Filed | April 30, 2025 Update Adjustments Reference | Amount | 12 mos. Ended September 30, 2025 April Update | Updated Revenue Requirement | As Adjusted for Additional Rrevenue |
| Operating Revenues: | | | | | | |
| Sales of Electricity - Retail Sales | $ 16,111,800 | | $ - | $ 16,111,800 | $ 1,656,800 | $ 17,768,600 |
| Other Operating Revenues | 125,100 | | - | 125,100 | - | 125,100 |
| Total Operating Revenues | 16,236,900 | | - | 16,236,900 | 1,656,800 | 17,893,700 |
| Operating Expenses: | | | | | | |
| Purchased Electric Power Costs | 7,964,400 | | - | 7,964,400 | - | 7,964,400 |
| Other Power Supply Expenses | 771,600 | | - | 771,600 | | 771,600 |
| Deferred Purchased Power Expense | | | | | | |
| Other Operation and | | | | | | |
| Maintenance Expenses | 3,447,700 | Sch. 4 | (170,000) | 3,082,400 | 4,600 | 3,087,000 |
| | | Sch. 5 | (187,500) | | | |
| | | Sch. 4 | (7,800) | | | |
| | | | - | | | |
| Depreciation Expense | 1,358,200 | Sch. 6 | (39,500) | 1,224,700 | - | 1,224,700 |
| | | Sch. 6 | (94,000) | | | |
| Taxes other than Income | 1,016,400 | | - | 1,016,400 | 97,800 | 1,114,200 |
| Total Operating Expenses | 14,558,300 | | (498,800) | 14,059,500 | 102,400 | 14,660,700 |
| Operating Income Before Income Taxes: | 1,678,600 | | 498,800 | 2,177,400 | 1,554,400 | 3,731,800 |
| State Income Tax | (90,700) | Sch. 12 | 163,900 | 73,200 | 124,200 | 197,400 |
| Federal Income Tax | (219,400) | Sch. 12 | 375,200 | 155,800 | 300,300 | 456,100 |
| Operating Income after Taxes | $ 1,988,700 | | $ (40,300) | $ 1,948,400 | $ 1,129,900 | $ 3,078,300 |
| Rate Base | $ 39,033,539 | Sch. 3 | $ (2,256,350) | $ 36,777,189 | $ - | $ 36,777,189 |
| Rate of Return | 5.09% | | | 5.30% | | 8.37% |

**Pike AP-E Update**
**Schedule 2**

Pike County Light And Power Company, Inc.
Electric Rate Cast R-2024-3052359
Calculation of Electric Revenue Requirement
For the Twelve Months Ended September 30, 2025

| | | | As Filed Amount | Update Adjustments | As Adjusted |
|---|---|---|---|---|---|
| Rate base at 09/30/2025 | | | $ 39,033,539 | $ (2,256,350) | $ 36,777,189 |
| Rate of Return at 09/30/2025 | | | 8.37% | 8.37% | 8.37% |
| Total Return Required | | | 3,267,107 | (188,856) | 3,078,251 |
| Total Earned Return | | | 1,988,700 | (40,300) | 1,948,400 |
| Addition Return Required | | | 1,278,407 | (148,556) | 1,129,851 |
| Multiplied by Retention Factor* | | | 1.4664 | 1.4664 | 1.4664 |
| Total Revenue Requirement | | | $ 1,874,613 | $ (217,838) | $ 1,656,775 |
| Rounded | | | $ 1,874,600 | $ (217,700) | $ 1,656,800 |
| * | Retention Factor: | | | | |
| | Additional Revenue | 100.0000 | 1,874,600 | (217,700) | 1,656,800 |
| | Less: Revenue Taxes @ 5.9% | 5.9000 | 110,600 | (12,800) | 97,800 |
| | Less: Uncollectibles | 0.2800 | 5,200 | (600) | 4,600 |
| | | 93.8200 | 1,758,800 | (204,300) | 1,554,400 |
| | Less: State Income Tax @ 7.99% | 7.4962 | 140,500 | (16,300) | 124,200 |
| | | 86.3238 | 1,618,300 | (188,000) | 1,430,200 |
| | Less: Federal Income Tax @ 21% | 18.1280 | 339,800 | (39,500) | 300,300 |
| | Retention Factor | 68.1958 | 1,278,500 | (148,500) | 1,129,900 |

**Pike AP-E Update**
**Schedule 3**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
Electric Rate Base
At September 30, 2025

| Description | As Filed Future Year at 09/30/25 | April 30, 2025 Update Adjustments Reference | Amount | Future Year at 09/30/25 |
|---|---|---|---|---|
| | (d)=(a)+(c) | (b) | (c) | (d)=(a)+(c) |
| Utility Plant: | | | | |
| Electric Plant in Service | $ 43,529,439 | Sch. 7 | $ (2,175,000) | $ 41,354,439 |
| Common Plant in Service (Allocated) | 1,532,400 | Sch. 7 | (127,500) | 1,404,900 |
| General Plant allocated from Corning Gas (N | 204,000 | | - | 204,000 |
| CWIP not taking interest | - | | - | - |
| Total Utility Plant | 45,265,839 | | (2,302,500) | 42,963,339 |
| | | | | |
| Utility Plant Reserves: | | | | |
| Accumulated Provision For Depreciation | | | | |
| of Electric Plant in Service | 5,411,400 | Sch. 8 | (447,200) | 4,964,200 |
| Accumulated Provision For Depreciation | | | | |
| of Common Plant in Service (Allocated) | 1,312,600 | Sch. 8 | (79,050) | 1,233,550 |
| Retirement W.I.P | (63,200) | | - | (63,200) |
| Total Utility Plant Reserves | 6,660,800 | | (526,250) | 6,134,550 |
| | | | | |
| Net Plant | 38,605,039 | | (1,776,250) | 36,828,789 |
| | | | | |
| Additions to Net Plant | | | | |
| Working Capital Requirements: | | | | |
| Cash Working Capital | 548,500 | Sch. 9 | 16,700 | 565,200 |
| Materials and Supplies | 1,568,400 | | - | 1,568,400 |
| Prepayments | 26,500 | | - | 26,500 |
| Deferred Debits (Net of Tax) | 302,100 | Sch. 10 | (302,100) | - |
| Total Additions | 2,445,500 | | (285,400) | 2,160,100 |
| | | | | |
| Deductions to Net Plant: | | | | |
| Deferred Credits | (91,900) | Sch. 11 | 218,400 | 126,500 |
| Customer Deposits | 335,900 | | - | 335,900 |
| Accumulated Deferred Income Taxes | 1,773,000 | Sch. 12 | (23,700) | 1,749,300 |
| Total Deductions | 2,017,000 | | 194,700 | 2,211,700 |
| | | | | |
| Electric Rate Base | $ 39,033,539 | | $ (2,256,350) | $ 36,777,189 |

**Pike AP-E Update**
**Schedule 4**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
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 | 85% | 85% | 85% |
| **Intercompany costs Alloc. to Electric** | **$ 663,150** | **$ (170,000)** | **$ 493,150** |
| | | | |
| Total Intercompany Allocations | $ 780,177 | $ (780,177) | $ - |
| x CPI Increase | 1.00% | 1.00% | 2.00% |
| **Net Change** | **$ 7,802** | **$ (7,802)** | **$ 11,604** |
| **Escalation Adjustment Rounded** | **$ 7,800** | **$ (7,800)** | **$ 11,600** |

**Pike AP-E Update**
**Schedule 5**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
Expense Adjustment for Minor Storms
For the Twelve Months Ended September 30, 2025

| | $ Amount | | | | |
|---|---|---|---|---|---|
| **Amortization of Storm Deferral Balances** | Balance At 9/30/2023 | Amortization 10/1/23 - 9/30/24 | Balance At 9/30/2024 | Update Adjustment | Updated Balance |
| Deferred Storm Balance | | | | | |
| - Riley | $ 541,921 | (195,528) | $ 346,393 | $ - | $ 346,393 |
| - Minor Storms (future estimate) | - | 150,000 | 150,000 | (150,000) | - |
| | - | - | - | - | - |
| Total | $ 541,921 | $ (45,528) | 496,393 | (150,000) | 346,393 |
| Amortization 10/1/24 - 9/30/25 | | | (195,528) | - | (195,528) |
| Unrecovered Balance at 9/30/2025 | | | 300,865 | (150,000) | 150,865 |
| Recovery Period (Years) | | | 4 | - | 4 |
| Annual Amount to be Amortized | | | $ 75,216 | (37,500) | 37,716 |
| Less: Annual amortization of Deferred Storm Charges | | | | | |
| In Twelve Months Ended September 30, 2024 | | | (45,528) | - | (45,528) |
| Net Increase | | | $ 29,688 | $ (37,500) | $ (7,812) |
| Rounded | | | $ 29,700 | $ (187,500) | $ (157,800) |

**Pike AP-E Update**
**Schedule 6**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
Depreciation Expense Adjustment
For the Twelve Months Ended September 30, 2025

| | Electric Dist. Plant | Common Plant Plant Allocated | Total Electric |
|---|---|---|---|
| Electric Distribution Plant in Service | | | |
| At September 30, 2024 Per Exhibit E-3, Schedule 12 | $ 34,737,197 | $ 1,244,289 | $ 35,981,486 |
| Less: Acquisition Adjustment | - | - | - |
| Electric Plant at June 30, 2020 | $ 34,737,197 | $ 1,244,289 | $ 35,981,486 |
| Less: Non-Depreciable Plant | (1,087,646) | (264,350) | (1,351,996) |
| Depreciable Plant at September 30,2025 | 33,649,551 | 979,939 | 34,629,490 |
| | | | |
| Additions - October 1, 2024 thru September 30, 2025 | | | |
| Distribution - Completed CWIP at 9/30/2025 | 2,567,239 | - | 2,567,239 |
| Distribution / General Additions Plant | 4,300,000 | 510,000 | 4,810,000 |
| | | | |
| Additions - October 1, 2025 thru March 31, 2026 | | | |
| Distribution / General Additions | - | - | - |
| Total Additions | 6,867,239 | 510,000 | 7,377,239 |
| | | | |
| Retirements - October 1, 2024 thru September 30, 2025 | | | |
| Distribution / General Plant | (250,000) | (85,000) | (335,000) |
| | | | |
| Retirements - October 1, 2025 thru March 31, 2026 | | | |
| Distribution / General Plant | - | - | - |
| Total Retirements | (250,000) | (85,000) | (335,000) |
| | | | |
| Electric Depreciable Plant at September 30, 2025 | 40,266,790 | 1,404,939 | 41,671,729 |
| x Book Basis Average Composite Depreciation Rate | 2.488% | 15.866% | 2.939% |
| | | | |
| Calculated Accruals to Depreciation Expense | | | |
| For The Twelve Months Ended September 30, 2025 | 1,001,838 | 222,908 | 1,224,745 |
| Less: Depreciation Expense as Filed | 1,074,600 | 283,600 | 1,358,200 |
| | | | |
| Decrease In Depreciation Expense | $ (72,762) | $ (60,692) | $ (133,455) |
| | | | |
| Rounded | $ (72,800) | $ (60,700) | $ (133,500) |

**Pike AP-E Update**
**Schedule 7**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
Post Test Year Plant Additions
For the Twelve Months Ended September 30, 2025

| | **ELECTRIC PLANT IN SERVICE** | **Company January 2025 Filing** | **April Update Adjustments** | **April 30, 2025 Update Filing** |
|---|---|---|---|---|
| 1 | Electric Plant In Service - 8/30/2024 | $ 34,737,200 | $ - | $ 34,737,200 |
| 2 | Additions - Completed CWIP - 9/30/2024 | 2,567,239 | - | 2,567,239 |
| 3 | Additions - 10/1/2024 - 9/30/2025 | 4,300,000 | - | 4,300,000 |
| 4 | Additions - 10/1/2025 - 8/30/2026 | 2,300,000 | (2,300,000) | - |
| **5** | **Total Plant** | **$ 43,904,439** | **$ (2,300,000)** | **$ 41,604,439** |
| | | | | |
| 6 | Retirements 10/1/2024 -9/30/2025 | (250,000) | - | (250,000) |
| | Retirements 10/1/2025 -9/30/2026 | (125,000) | 125,000 | - |
| **7** | **Total Retirements** | **$ 43,529,439** | **$ (2,175,000)** | **$ 41,354,439** |
| | | | | |
| | **COMMON PLANT ALLOCATED TO ELECTRIC** | | | |
| 8 | Electric Common Plant In Service - 9/30/2024 | 1,152,869 | - | 1,152,869 |
| **9** | **Allocated to Electric - 85%** | **$ 979,939** | **$ -** | **$ 979,939** |
| 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 Electric - 85%** | **$ 680,000** | **$ (170,000)** | **$ 510,000** |
| | | | | |
| 15 | Retirements 10/1/2024 -9/30/2025 | (100,000) | - | (100,000) |
| | Retirements 10/1/2025 -9/30/2026 | (50,000) | 50,000 | - |
| **16** | **Allocated to Electric - 85%** | $ (127,500) | $ 42,500 | $ (85,000) |
| **17** | **Electric Common Plant In Service - 12/31/2021** | **$ 1,532,439** | **$ (127,500)** | **$ 1,404,939** |
| | **Rounded** | **$ 1,532,400** | **$ (127,500)** | **$ 1,404,900** |

**Pike AP-E Update**
**Schedule 8**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
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** | **Electric Reserve Balance - 9/30/2024** | **$ 4,247,700** | **$ -** | **$ 4,247,700** |
| 2 | Additions - 10/1/2024 - 9/30/2025 | $ 966,500 | $ - | $ 966,500 |
| 3 | Additions - 10/1/2025 - 8/30/2026 | 572,200 | $ (572,200) | $ - |
| 4 | Total Electric Reserve | $ 1,538,700 | $ (572,200) | $ 966,500 |
| | Retirements 10/1/2024 -9/30/2025 | $ (250,000) | $ - | $ (250,000) |
| 5 | Retirements 10/1/2025 -9/30/2026 | $ (125,000) | $ 125,000 | $ - |
| **6** | **Net Additions** | **$ 1,163,700** | **$ (447,200)** | **$ 716,500** |
| **7** | **Electric Reserve Balance - 9/30/2025** | **$ 5,411,400** | **$ (447,200)** | **$ 4,964,200** |
| **8** | **Common Electric Reserve Balance - 9/30/2024** | **$ 1,328,583** | **$ -** | **$ 1,328,583** |
| 9 | **Allocated to Electric - 85%** | **$ 1,129,295** | $ - | **$ 1,129,295** |
| | **Rounded** | **$ 1,129,300** | **$ -** | **$ 1,129,300** |
| 10 | Additions - 10/1/2024 - 9/30/2025 | $ 222,600 | $ - | $ 222,600 |
| 11 | Additions - 10/1/2025 - 8/30/2026 | $ 143,000 | $ (143,000) | $ - |
| 12 | Total Common Additions to Electric Reserve | $ 365,600 | $ (143,000) | $ 222,600 |
| **13** | **Allocated to Electric - 85%** | **$ 310,760** | **$ (121,550)** | **$ 189,210** |
| | **Rounded** | **$ 310,760** | **$ (121,550)** | **$ 189,210** |
| | Retirements 10/1/2024 -9/30/2025 | $ (100,000) | $ - | $ (100,000) |
| | Retirements 10/1/2025 -9/30/2026 | $ (50,000) | $ 50,000 | $ - |
| **14** | **Allocated to Electric - 85%** | **$ (127,500)** | **$ 42,500** | **$ (85,000)** |
| | **Rounded** | **$ (127,500)** | **$ 42,500** | **$ (85,000)** |
| **15** | **Common Electric Ending Balance - 12/31/2021** | **$ 1,312,560** | **$ (79,050)** | **$ 1,233,510** |
| 16 | Lines 18, 23, 26) | | | |
| **17** | **Total Electric Reserve Balance - (**Lines 15, 28) | **$ 6,723,960** | **$ (526,250)** | **$ 6,197,710** |

**Pike AP-E Update**
**Schedule 9**

Pike County Light And Power Company, Inc
Electric Rate Cast R-2024-3052359
Cash Working Capital Adjustment for Intercompany Charges
For the Twelve Months Ended September 30, 2025

| | Reference | Rate Year Amount | (Lead) / Lag Days | Dollar Days |
|---|---|---|---|---|
| Revenue Recovery | Sch. 1 | 15,878,371 | 21.3 | $ 338,209,313 |
| Pennsylvania Gross Receipts Tax | Sch. 1 | 995,500 | 21.3 | 21,204,150 |
| | | 16,873,871 | 21.3 | 359,413,463 |
| | | | | |
| Purchased Power Expenses | Sch. 2 | 7,964,400 | 10.0 | 79,644,000 |
| SBC Expense | Sch 1 | 11,204 | 30.0 | 336,107 |
| Salaries & Wages | Sch. 3 | 482,104 | 8.0 | 3,856,832 |
| 401K Pension Match | Sch. 4 | 31,902 | 8.0 | 255,216 |
| Employee Welfare Expenses | Sch. 5 | 423,591 | 23.0 | 9,742,584 |
| Intercompany Charges | Sch. 5 | 493,151 | 30.0 | 14,794,521 |
| Uncollectible Accounts Accrual | Sch. 6 | 47,247 | 8.0 | 377,975 |
| Other O&M | Sch. 7 | 1,796,102 | 23.0 | 41,310,350 |
| Amortizations: | | - | | - |
| Storm Reserve | Sch. 8 | 300,865 | - | - |
| Rate Case Costs | Sch. 8 | - | - | - |
| PUC Assessment | Sch. 8 | 36,642 | - | - |
| Insurance | Sch. 8 | - | - | - |
| Depreciation & Amortization | Sch. 8 | 1,358,200 | - | - |
| Taxes Other - Payroll | Sch. 4 | 36,881 | 8.0 | 295,048 |
| - Property Tax | Sch. 8 | 18,338 | - | - |
| Pennsylvania Gross Receipts Tax | Sch. 8 | 995,500 | - | - |
| Income Taxes: | | | | - |
| Federal Income Tax | Sch. 9 | 56,840 | 30.0 | 1,705,215 |
| Deferred Federal Income Tax | Sch. 8 | 60,213 | - | - |
| Corporate Business Tax (State) | Sch. 10 | 26,544 | 30.0 | 796,333 |
| Deferred State Income Tax | Sch. 8 | 22,910 | - | - |
| Return on Invested Capital | Sch. 8 | 1,122,700 | - | - |
| Total Requirement | | 15,285,334 | 10.0 | 153,114,180 |
| | | | | |
| Net Lag | | | 11.3 | $ 206,299,282 |
| | | | | |
| Net Requirement (Net Lag / 365 ) | | | | $ 565,204 |
| | | | | |
| Cash Working Capital - As Filed | | | | 548,495 |
| | | | | |
| Net Change | | | | $ 16,709 |
| | | | | |
| Rounded | | | | $ 16,700 |

| | | | |
|---|---|---|---|
| | | | **Pike AP-E Update** |
| | | | **Schedule 10** |

**Pike County Light And Power Company, Inc.**

Electric Rate Cast R-2024-3052359

Adjustment to Eliminate Storm and Rate Case Costs from Rate Base

For the Twelve Months Ended September 30, 2025

| | 12 Months Ended 9/30/2024 | Update Adjustments | As Adjusted |
|---|---|---|---|
| **AMORTIZATION OF STORM DEFERRALS** | (1) | (2) | (3) = (1+2) |
| Hurricane Riley- 9/30/2024 | $ 346,393 | $ (346,393) | $ - |
| Spending 9/30/2024 - 9/30/2025 | $ - | $ - | $ - |
| **Balance at 6/30/2019** | **$ 346,393** | **$ -** | **$ -** |
| Amortization - Hurricane Riley 9/30/2024 - 9/30/2025 | $ (195,528) | $ 195,528 | $ - |
| Amortization - Minor Storm Cost | $ - | $ - | $ - |
| **Balance at 9/30/2025** | **$ 150,865** | **$ (150,865)** | **$ -** |
| **AMORTIZATION OF RATE CASE COSTS** | | | |
| Rate Case Costs - 9/30/2024 | $ 113,857 | $ (113,857) | $ - |
| Spending 9/30/2024 - 9/30/2025 | $ 212,500 | $ (212,500) | $ - |
| **Balance at 6/30/2019** | **$ 326,357** | **$ -** | **$ -** |
| Amortization - Hurricane Riley 9/30/2024 - 9/30/2025 | $ (61,613) | $ 61,613 | $ - |
| Amortization - Minor Storm Cost | $ - | $ - | $ - |
| **Balance at 9/30/2025** | **$ 264,745** | **$ (264,745)** | **$ -** |
| **Unrecovered Balance - 9/30/2025** | **$ 415,610** | **$ (415,610)** | **$ -** |
| **After Tax Balance** | **$ 302,098** | **$ (302,098)** | **$ -** |
| **Rounded** | **$ 302,100** | **$ (302,100)** | **$ -** |

**Pike AP-E Update**
**Schedule 11**

**Pike County Light And Power Company, Inc.**
Electric Rate Cast R-2024-3052359
Adjustment to Correct Rate Base Deduction for Deferred Credits (TCJA Tax Benefits)
For the Twelve Months Ended September 30, 2025

| Deferred TCJA Tax Credits - Current | 12 Months Ended 9/30/2024 As Filed (1) | Update Adjustments (2) | As Adjusted (3) = (1+2) |
|---|---|---|---|
| Deferred FIT Benefits - Acct 186150 | $ (15,133) | $ 30,266 | $ 15,133 |
| Spending 9/30/2024 - 9/30/2025 | - | - | - |
| **Balance at 9/30/2024** | (15,133) | 30,266 | 15,133 |
| Amortization - 10/1/2024 - 9/30/2025 | - | - | - |
| **Balance at 9/30/2025** | **$ (15,133)** | **$ 30,266** | **$ 15,133** |
| AMORTIZATION OF FIT RATE CHANGE - PLANT | | | |
| Deferred FIT Benefits Acct 253911 & 253921 | $ (128,752) | $ 257,504 | $ 128,752 |
| Spending 9/30/2024 - 9/30/2025 | - | - | - |
| Balance at 9/30/2024 | (128,752) | 257,504 | 128,752 |
| Amortization - 10/1/2024 - 9/30/2025 | 17,420 | (34,840) | (17,420) |
| **Balance at 9/30/2025** | **$ (111,332)** | **$ 222,664** | **$ 111,332** |
| **Total Unrecovered Balance - 9/30/2025** | **$ (126,465)** | **$ 252,930** | **$ 126,465** |
| **After Tax Balance** | **$ (91,925)** | **$ 218,390** | **$ 126,465** |
| **Rounded** | **$ (91,900)** | **$ 218,400** | **$ 126,500** |

Pike AP-E Update
Schedule 12
Page 1 of 3

**Pike County Light And Power Company, Inc.**
Electric Rate Cast R-2024-3052359
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 | $ 1,678,600 | $ 498,800 | $ 2,177,400 |
| 2 | Less: Interest Expense | $ 2,814,318 | $ (1,552,861) | $ 1,261,458 |
| **3** | **Income Before Federal Income Tax** | **$ (1,135,718)** | **$ 2,051,661** | **$ 915,942** |
| | | | | |
| | Add: | | | |
| 4 | Book Depreciation | 1,358,200 | - | $ 1,358,200 |
| 5 | Amortization of Rate Case Expenses | 53,100 | - | $ 53,100 |
| 6 | Amortization of Deferred Storm Costs | 75,228 | - | $ 75,228 |
| **7** | **Total** | **$ 1,486,528** | **$ -** | **$ 1,486,528** |
| | | | | |
| | Deduct: | | | |
| 8 | Tax Depreciation | 1,560,756 | - | $ 1,560,756 |
| 9 | Deferred Rate Case Expense | 212,500 | - | $ 212,500 |
| 10 | Deferred Storm Costs | - | - | $ - |
| 11 | Amortization - Deferred FIT Customer Cr. | - | - | $ - |
| **12** | **Total** | **$ 1,773,256** | **$ -** | **$ 1,773,256** |
| | | | | |
| **13** | **Taxable Income** | **$ (1,422,446)** | **$ 2,051,661** | **$ 629,214** |
| 14 | State Income Tax Rate - 9.99% | 7.99% | 7.99% | 7.99% |
| | | | | |
| 15 | State Income Tax | $ (113,653) | $ 163,928 | $ 50,274 |
| 16 | Deferred Income Tax Dr. | 141,683 | - | 141,683 |
| 17 | Deferred Income Tax Cr. | (118,774) | - | (118,774) |
| **18** | **Total State Income Tax** | **$ (90,744)** | **$ 163,928** | **$ 73,184** |
| | | | | |
| | Rounded | **$ (90,700)** | **$ 163,900** | **$ 73,200** |

Pike AP-E Update
Schedule 12
Page 2 of 3

**Pike County Light And Power Company, Inc.**
Electric Rate Cast R-2024-3052359
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 | $ (1,422,446) | $ 2,051,661 | $ 629,214 |
| 2 | Less: State Income Tax | 90,744 | (163,928) | (73,183) |
| 3 | Federal Tax Adjustment | - | - | - |
| **4** | **Adjusted Taxable Income** | **$ (1,331,702)** | **$ 1,887,733** | **$ 556,031** |
| | | | | |
| 5 | Federal Income Tax Rate 21.00% | 21.00% | 21.00% | 21.00% |
| **6** | **Current Federal Income Tax** | **$ (279,657)** | **$ 396,424** | **$ 116,767** |
| | | | | |
| | Deferred FIT Applicable To: | | | |
| 7 | Book Depreciation | $ (285,222) | $ - | $ (285,222) |
| 8 | Amortization of Rate Case Expenses | (11,151) | - | (11,151) |
| 9 | Amortization of Deferred Storm Costs | (15,798) | - | (15,798) |
| 10 | Deferred FIT Customer Cr. | - | - | - |
| 11 | Tax Depreciation | 327,759 | - | 327,759 |
| 12 | Deferred Rate Case Expenses | 44,625 | - | 44,625 |
| 13 | Amortization of Deferred FIT Customer Cr. | - | - | - |
| **14** | **Total** | **$ 60,213** | **$ -** | **$ 60,213** |
| | | | | |
| 15 | Current Federal Income Tax | $ (279,657) | $ 396,424 | $ 116,767 |
| 16 | Deferred Income Tax | 60,213 | - | 60,213 |
| | Amortization of Deferred FIT Customer Cr. | - | (21,212) | (21,212) |
| **17** | **Total** | **$ (219,444)** | **$ 375,212** | **$ 155,768** |
| | | | | |
| | Rounded | **$ (219,400)** | **$ 375,200** | **$ 155,800** |

**Pike AP-E Update**
**Schedule 12**
**Page 3 of 3**

**Pike County Light And Power Company, Inc.**
Electric Rate Cast R-2024-3052359
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 | $ 39,033,539 | $ (2,256,350) | $ 36,777,189 |
| Interest Component of Capitalization | 7.21% | -3.78% | 3.43% |
| Interest Expense | $ 2,814,318 | $ (1,552,861) | $ 1,261,458 |
| Rounded | $ 2,814,300 | $ (1,552,900) | $ 1,261,500 |

# 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


WEDBUSH SECURITIES INC. 142 W 57th Street, 12th Floor | New York, NY 10019 | (212) 259-6580 | wedbush.com

$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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Signer bard.cook@wedbush.com entered name at signing as Bard Cook
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Document e-signed by Bard Cook (bard.cook@wedbush.com)
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Agreement completed.
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**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

| | | |
|---|---|---|
| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | DOCKET NO. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company (electric) | : | |

**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 D.C. Patel on behalf of the Bureau of Investigation and Enforcement ("I&E")[1] and Maureen L. Reno

---

[1] Pennsylvania Public Utility Commission, Docket No. R-2024-3052359, Direct Testimony of D.C. Patel, April 3, 2025 ("Patel Direct Testimony").

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-8R, 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 Ms. Reno's cost of equity and capital structure analyses and recommendations.

## II. SUMMARY OF ANALYSIS AND CONCLUSIONS

**Q. What analyses do Mr. Patel and Ms. Reno conduct, and what ROEs are each recommending for the Company in this proceeding.**

A. While Mr. Patel does not conduct any cost of equity analyses, he recommends that the Commission accept the Company's requested ROE of 9.75 percent.[3] Additionally, Mr.

---

[2] Pennsylvania Public Utility Commission, Docket No. R-2024-3052359, Direct Testimony of Maureen L. Reno, April 3, 2025 ("Reno Direct Testimony").

[3] Patel Direct Testimony, at 12.

Patel proposes to accept the Company's capital structure composed of 50.52 percent common equity, 40.82 percent long-term debt, and 8.66 percent short-term debt.[4]

Figure 1 summarizes the cost of equity model results, ROE, and capital structure recommendations of Ms. Reno. Ms. Reno prepares a constant growth Discounted Cash Flow ("DCF") analysis and a Capital Asset Pricing Model ("CAPM") analysis; however, her recommended ROE of 9.40 percent is 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.[5] Ms. Reno proposes to accept the Company proposed capital structure but recommends that Pike's equity ratio of 50.52 percent be "established as a maximum".[6]

---

4 *Id.*

5 Reno Direct Testimony, at 8.

6 *Id.,* at 24.

**Figure 1: Summary of Ms. Reno's**
**Cost of Equity Model Results**

| | Reno Low | Reno High |
|---|---|---|
| **Constant Growth DCF** | | |
| Proj. EPS Growth Rates | 10.22% | 10.34% |
| Proj. EPS, BVPS & DPS Growth Rates | 9.12% | 9.10% |
| Sustainable Growth Rate | 8.44% | 8.50% |
| **Midpoint** | **9.39%** | |
| CAPM | 8.20% | 11.44% |
| **Midpoint** | **9.82%** | |
| **Recommended ROE** | **9.40%** | |
| Capital Structure | | |
| Common Equity | 50.52% | |
| Short-term Debt | 8.66% | |
| Long-Term Debt | 40.81% | |

**Q. Will you be providing a response to Mr. Patel's recommendations regarding the appropriate ROE and capital structure for Pike?**

A. No, I will not because Mr. Patel supports both the Company's requested ROE of 9.75 percent and proposed capital structure. As a result, the remainder of my rebuttal testimony will response to direct testimony of Ms. Reno regarding the appropriate ROE and capital structure for the Company.

**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 Ms. Reno's direct testimony, my key conclusions regarding the Company's revised proposed ROE and capital structure are as follows:

- While I disagree with various aspects of the cost of equity models conducted by Ms. Reno in this proceeding, the fundamental issue is that her ROE recommendation does 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 252 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 T&D electric utilities have increased.
    - Despite the increase in the cost of equity demonstrated by current market conditions, Ms. Reno's recommended ROE of 9.40 percent is below the average authorized return for T&D electric utilities across the U.S. in 2024 and is in fact at the very low-end of the range returns authorized for T&D electric utilities in 2024. As a result, Ms. Reno's recommendation is 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 9.40 percent to 9.90 percent, or greater than the Company's requested ROE of 9.75 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 10.17 percent while the midpoint of the adjusted CAPM is 10.40 percent, each of which is substantially higher than the Company's requested ROE in this proceeding of 9.75 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.[7]
    - 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 10.29 percent.
- Ms. Reno incorrectly concludes that the Company has similar business risk as the companies included in her proxy group because she failed compare the regulatory mechanisms of the Company to the regulatory mechanisms of the proxy group companies in her assessment of regulatory risk and did not consider the Company's small size risk.
    - Considering the regulatory adjustment mechanisms, many of the companies in Ms. Reno's proxy group have more timely cost recovery between rate proceedings than Pike has in Pennsylvania; thus, the Company has slightly greater than average regulatory risk relative to Ms. Reno's proxy group. Furthermore, Pike has substantial risk associated with the small size of its electric operations in Pennsylvania. Considering both the increased regulatory and size risk of Pike, it is reasonable to conclude that the Company has greater business risk relative to Ms. Reno's proxy group.
- Ms. Reno's recommendation to set a "maximum" equity ratio at the Company's proposed equity ratio of 50.52 percent is unreasonable because:
    - an equity ratio of 50.52 percent is 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 below the proxy

[7] *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).

group average equity ratios and therefore indicates greater financial risk relative to the proxy group.

- an equity ratio of 50.52 percent is consistent with the average authorized equity ratios for T&D electric utilities from 2020-2024 and well below the maximum equity ratio authorized over this time-period.

## 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.[8] 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.[9] Finally, Ms. Reno notes that both the national and Pennsylvania economy continue to grow and remain strong.[10] According to Ms. Reno, investors will consider each of these factors in determining their cost of equity over the long-term.[11] 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.

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[8] Reno Direct Testimony, at 14.

[9] *Id.,* at 17-18.

[10] *Id.,* at 18-19.

[11] *Id.,* at 13.

**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.[12] 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 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.[13]

**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.[14]

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

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[12] *Id.,* at 20.

[13] *Id.*, at 20-21.

[14] *Id.,* 20.

> T-Bills are falling slightly, which suggests that investors may not be expecting an economic slowdown.[15]

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.[16] The evidence provided by Ms. Reno shows that investors 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.[17] Therefore, the federal funds rate is also expected to remain well above the levels seen at

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[15] *Id.,* 17.

[16] *Id.,* 18.

[17] Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

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.

**Figure 2: Changes in Capital Market Conditions Since Pike's Last Rate Proceeding[18]**

| Period | Date | Federal Funds Rate | 30-Day Avg of 30-Year Treasury Bond Yield | Core Inflation Rate |
|---|---|---|---|---|
| Docket No. R-2020-3022135 | 7/15/2021 | 0.10% | 2.09% | 4.21% |
| Current | 3/31/2025 | 4.33% | 4.61% | 2.81% |
| Change | | 4.23% | 2.52% | -1.40% |

**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.[19] 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.[20] 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.[21] Thus, the FOMC's forecast of the federal

[18] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.
[19] Transcript of Chairman Powell's Press Conference (March 19, 2025).
[20] *Id.*
[21] *Id.*

funds rate remained unchanged from the December 2024 meeting, forecasting just two rate cuts before the end of 2025.[22]

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.[23] 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.[24]

**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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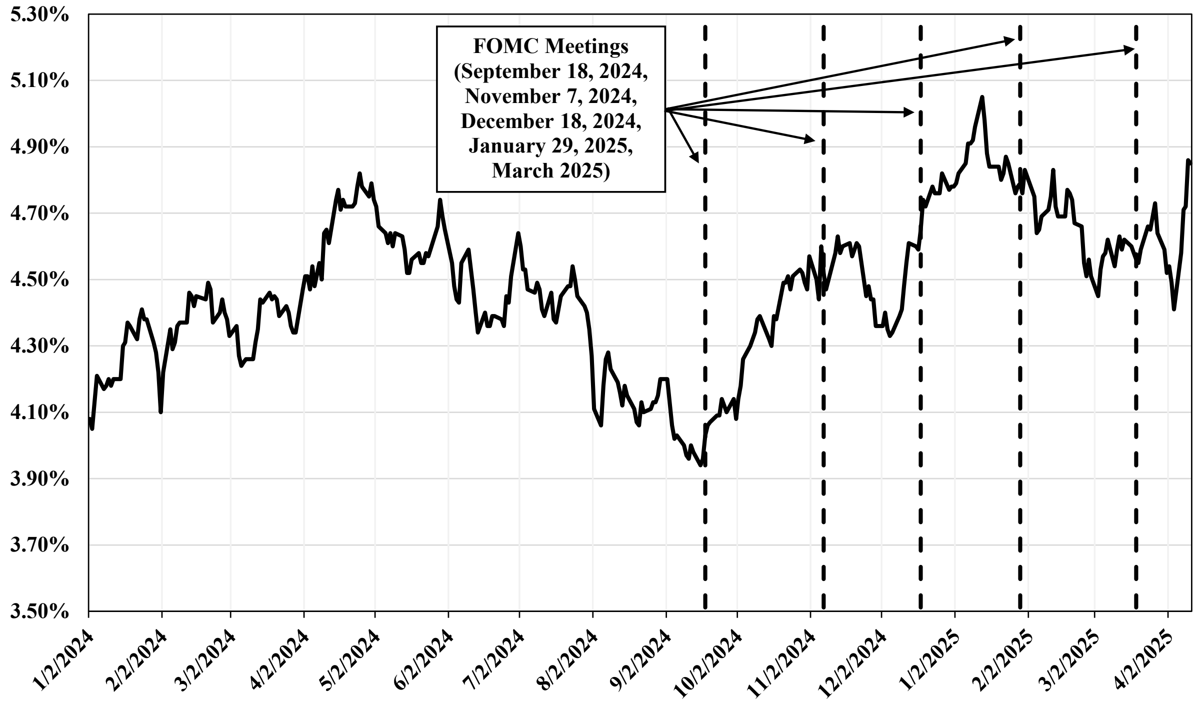
22 Federal Reserve, Summary of Economic Projections, March 19, 2025, at 2.

23 Howard Schneider and Ann Saphir, "Powell says Fed remains in wait-and-see mode; markets processing policy shifts," Reuters (April 16, 2025).

24 *Id.*

**Figure 3: 30-Year Treasury Bond Yield, January 1, 2024 – April 11, 2025[25]**




**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.[26] 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

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[25] S&P Capital IQ Pro.

[26] 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.[27]

**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.[28] 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.[29] 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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27 Vanjani, Karishma, "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," Barron's (April 9, 2025).

28 *Blue Chip Financial Forecasts*, Vol. 44, No. 4, April 1, 2025, at 2.

29 *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. Does Ms. Reno agree that it is appropriate to consider previously authorized ROEs?**

A. Yes. Ms. Reno appears to benchmark her recommended ROE of 9.40 percent to the average authorized return for transmission and distribution ("T&D") electric utilities of 9.53 percent in 2024 and 9.24 percent in 2023.[30]

**Q. Do you have any concerns with the review of authorized returns conducted by Ms. Reno?**

A. Yes. I have three primary concerns with the review of authorized returns conducted by Ms. Reno:

- Ms. Reno fails 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.
- Ms. Reno has 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

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[30] Reno Direct Testimony, at 55-56.

have increased substantially over the past few years and are expected to remain elevated over the near-term.

- Ms. Reno relies on the annual average authorized returns instead of also considering the full range of authorized returns. For example, Ms. Reno relies on the average annual authorized returns for all T&D electric utilities to conclude that her recommendation is reasonable. 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 T&D electric 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.[31]
- 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 T&D electric utilities and interest rates have increased. Further, Ms. Reno's recommended ROE of 9.40 percent is not only below the average authorized ROE for T&D electric utilities in the U.S. in 2024 but is at the very low-end of the range returns authorized for T&D electric utilities in 2024.

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31 Docket No. 23-0055 for Commonwealth Edison and Docket No. 23-0082 for Ameren Illinois were also excluded because the Illinois Commerce Commission authorized the return in each case on the basis that the Multi-Year Rate Plan resulted in less business risk than either traditional ratemaking or a formula rate plan. See Illinois Commerce Commission, Order, Docket No. 23-0082, December 14, 2023, at 372; and Illinois Commerce Commission, Order, Docket No. 23-0055, December 14, 2023, at 462.

Finally, the Company's requested ROE of 9.75 percent is within the range of authorized returns for T&D electric utilities in 2024.

**Figure 4: Range of Annual Authorized ROE for T&D Electric Utilities, 2020-2024**[32]

| Year | Average | Min. | Max. | 30-Year Treasury Bond Yield |
|---|---|---|---|---|
| 2020 | 9.29% | 8.80% | 9.70% | 1.56% |
| 2021 | 9.46% | 9.00% | 9.70% | 2.05% |
| 2022 | 9.47% | 9.00% | 10.00% | 3.12% |
| 2023 | 9.41% | 9.20% | 9.70% | 4.09% |
| 2024 | 9.53% | 9.35% | 9.76% | 4.41% |

**Q. Is Ms. Reno's ROE recommendation for the Company in this proceeding reasonable based on a comparison to recent authorized returns for T&D electric utilities?**

A. No. Ms. Reno's ROE recommendation of 9.40 percent is 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. It is therefore unreasonable to conclude that Ms. Reno's ROE recommendation would reflect the investor-required return on equity for a T&D electric utility in current market conditions.

## IV. 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;

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32 S&P Capital IQ Pro.

- 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. <u>Proxy Group</u>**

**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 electric 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.[33] The screening criteria resulted in a proxy group consisting of 28 electric utilities that Ms. Reno notes is the same 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 electric utilities in the June 2024 report.[34]

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[33] Reno Direct Testimony, at 30.

[34] *Id.*

**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 Eversource Energy ("ES"), MGE Energy, Inc. ("MGEE") and Otter Tail Corporation ("OTTR") in her proxy group. For example, Ms. Reno contends that she required companies not be involved in a transformative transaction; however, on January 27, 2025, ES agreed to sell its subsidiary Aquarion Water Company, Inc. for $2.4 billion to the Aquarion Water Authority.[35] Therefore, ES is currently engaged in a transformative transaction and should have been excluded from Ms. Reno's proxy group.

Similarly, Ms. Reno contends that she required companies be covered by at least two utility equity analysts'; however, as shown in Schedule MLR-5a, MGEE has a projected EPS growth rate from *Value Line* but does not have a projected EPS growth rate from either *S&P Capital IQ Pro* or *Zacks*. MGEE is only covered by one equity analyst and should have been excluded from Ms. Reno's proxy group.

Finally, Ms. Reno does not apply a screening criterion to determine the portion of unregulated operations for each of the electric 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 CMW-2R, OTTR derives only approximately 30 percent of

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[35] Doerr, Heike, "Eversource's Aquarion sale awaits key regulatory approvals", January 29, 2025.

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. Constant Growth DCF Analysis

**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 8.44 percent to 10.34 percent, with a midpoint of 9.39 percent.[36]

#### 1. Selection of the Growth Rate in the Constant Growth DCF model

**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

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[36] Reno Direct Testimony, at 47.

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 9.10 percent to 9.12 percent. The results of Ms. Reno's constant growth DCF scenario using sustainable growth rates range from 8.44 percent to 8.50 percent.[37] The results of both these scenarios are either below or at the low-end of any authorized ROE for an electric 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:

- 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.[38]
- 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.[39] These dividend

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37 Reno Direct Testimony, at 47.

38 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).

39 Langley, Karen. "U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade." Wall Street Journal, July 8, 2020.

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.[40] 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.

- 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).[41]

- 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

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[40] *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.

[41] Block, Stanley B. "A Study of Financial Analysts: Practice and Theory." *Financial Analysts Journal*, July/August 1999.

> 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 the future if EPS and DPS are expected to growth at a constant rate.[42] 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.

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[42] Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, *Risk and Return for Regulated Industries*, 2017, at 99.

**Q. Have you considered whether *Value Line*'s projected DPS and EPS growth rates are equivalent?**

A. Yes. As shown in Figure 5, *Value Line* only projects DPS growth to be equivalent to EPS growth for 5 of the 27 companies included in Ms. Reno's proxy group for which *Value Line* provides projected EPS and DPS growth.[43] 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.

[43] Ms. Reno's proxy group includes 28 companies; however, Value Line does not provide EPS and DPS growth rates for Exelon Corporation.

**Figure 5: *Value Line's* Projected EPS and DPS Growth Rates for Ms. Reno's Proxy Group**[44]

| | *Value Line* Projected | | **Difference** |
|---|---|---|---|
| | **EPS** | **DPS** | **(EPS - DPS)** |
| Alliant Energy Corporation | 6.00% | 6.00% | 0.00% |
| Ameren Corporation | 6.50% | 6.50% | 0.00% |
| American Electric Power Company, Inc. | 6.50% | 5.50% | 1.00% |
| Avista Corporation | 5.50% | 4.00% | 1.50% |
| CMS Energy Corporation | 6.00% | 5.00% | 1.00% |
| Consolidated Edison, Inc. | 6.00% | 4.00% | 2.00% |
| Dominion Resources, Inc. | 3.50% | 0.50% | 3.00% |
| DTE Energy Company | 4.50% | 3.00% | 1.50% |
| Duke Energy Corporation | 6.00% | 3.50% | 2.50% |
| Edison International | 6.50% | 6.00% | 0.50% |
| Entergy Corporation | 3.00% | 5.50% | -2.50% |
| Eversource Energy | 5.50% | 6.00% | -0.50% |
| Evergy, Inc. | 7.50% | 7.00% | 0.50% |
| Exelon Corporation | N/A | N/A | N/A |
| FirstEnergy Corporation | 5.50% | 5.50% | 0.00% |
| IDACORP, Inc. | 6.00% | 5.50% | 0.50% |
| MGE Energy, Inc. | 7.00% | 6.50% | 0.50% |
| NextEra Energy, Inc. | 8.50% | 9.50% | -1.00% |
| NorthWestern Corporation | 4.50% | 1.50% | 3.00% |
| OGE Energy Corporation | 6.50% | 3.00% | 3.50% |
| Otter Tail Corporation | 4.50% | 7.00% | -2.50% |
| Pinnacle West Capital Corporation | 4.00% | 1.50% | 2.50% |
| TXNM Energy | 4.00% | 5.50% | -1.50% |
| Portland General Electric Company | 5.50% | 5.50% | 0.00% |
| PPL Corporation | 7.50% | -0.50% | 8.00% |
| Public Service Enterprise Group Inc. | 6.00% | 6.00% | 0.00% |
| Southern Company | 6.50% | 3.50% | 3.00% |
| Xcel Energy Inc. | 6.50% | 6.00% | 0.50% |

**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

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[44] Source: Schedule MLR-5a and Schedule MLR-5b.

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 5, 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.[45] 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.[46] 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.[47]

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[45] 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.

[46] 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.

[47] *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.[48] 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. ***<u>Thus, the best measure of growth for use in the DCF model are forecasted earnings growth rates</u>***.[49]

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[48] *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.

[49] 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 10.22 (*i.e.,* 30-day average share price) percent to 10.34 percent (*i.e.,* 90-day average share price).[50] The results support my conclusion that the Company's ROE request of 9.75 percent is a conservative estimate of the investor required return.

**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 9.40 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 8.44 percent to 10.34 percent, which was 9.39 percent.[51]

**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.[52]

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[50] Reno Direct Testimony, at 47

[51] Reno Direct Testimony, at 54.

[52] Kansas Corporation Commission, Docket No. 23-EKCE-775-RTS, Direct Testimony of Maureen L. Reno, August 29, 2023, at 52

However, Ms. Reno noted that, in determining her recommended ROE, she excluded the low-end of her DCF range because:

> 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).[53]

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.[54]

**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".[55] 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 8.44 percent to 9.39 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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53 *Id.*

54 *Id.,* at 52-53.

55 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 252 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 8.44 percent to 10.34 percent with a midpoint of 9.39 percent. If Ms. Reno excluded the low-end of her DCF range, her recommended ROE range would be 9.39 percent to 10.34 percent, with a midpoint of 9.87 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 9.40 percent to 9.90 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. In fact, Ms. Reno's decision to rely solely on the 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,[56] Columbia Water,[57] and PAWC[58]. 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 and that the Federal Reserve was ending its accommodative monetary policy to keep interest rates low

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[56] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, at 154-155 (Order entered May 16, 2022).

[57] *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 107-108 (Order Entered January 18, 2024).

[58] *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-2023-3043190, at 171-172 (Order Entered July 22, 2024).

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.[59] 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 Ms. Reno. 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.[60]

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.[61]

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 suggests that the DCF results may understate the utility's ROE, the Commission will

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[59] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket Nos. R-2021-3027385 & R-2021-3027386, at 154 (Order entered May 16, 2022).

[60] *Id.,* at 155.

[61] *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.

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.[62]

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.[63]

**Q. Are current market conditions still consistent with those that resulted in the Commission utilizing both the DCF and CAPM results in the determination of the ROE?**

A. Yes. As discussed in Section III above and 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. These 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. Therefore, consistent with the Commission's recent decisions, Ms. Reno should have relied on both her DCF and CAPM results for purposes

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[62] *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 107-108 (Order Entered January 18, 2024).

[63] *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.

of developing her recommended ROE, and by failing to do so, has understated the cost of equity for Pike.

### 4. Updated Constant Growth DCF Results

**Q. Have you updated Ms. Reno's constant growth DCF analysis to reflect more recent market data?**

A. Yes. Given the recent changes in market conditions referenced in Section III above and acknowledged by Ms. Reno, 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-3R, 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 10.10 percent while the median cost of equity for her 90-day average constant growth DCF using projected EPS growth rates is 10.24 percent. The updated constant growth DCF range of 10.10 percent to 10.24 percent provides support for my conclusion that the Company's requested ROE of 9.75 percent is conservative.

## C. CAPM Analysis

**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 8.20 percent to 11.44 percent.[64] 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.

[64] Reno Direct Testimony, at 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 8.20 percent, which is well below any authorized ROE in decades for an electric 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. 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-4R, 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 8.20 percent to 9.25 percent. The correction would also result in an updated CAPM range of 9.25 percent to 11.44 percent with a midpoint of 10.35 percent as opposed to Ms. Reno's filed CAPM range of 8.20 percent to 11.44 percent with a midpoint of 9.82 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[65] has been 4.87 percent;[66] 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 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 6, 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.

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65 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.

66 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.

**Figure 6: 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.[67]

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

[67] *Morningstar Inc*., 2010 Ibbotson SBBI Valuation Yearbook, at 55.

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."[68] 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.

**Q. Is there also evidence that the use of a historical market premium can produce counter-intuitive results?**

A. Yes. Figure 7 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,

[68] *Kroll*, 2022 SBBI Yearbook, at 198.

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 7: Historical Market Risk Premium and Market Volatility**

| | **Market Volatility** | **Market Return** | **Annual Equity Risk Premium** | **Long-term Average Historical Market Risk Premium**[69] |
|---|---|---|---|---|
| 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% |

**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

[69] 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.

applied to Ms. Reno's CAPM analyses, the results provide support for my conclusion that the Company's requested ROE of 9.75 percent is conservative.

**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.[70] As shown in Figure 8 (see also Exhibit CMW-4R), applying these reasonable updates and corrections to Ms.

[70] 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.

Reno's CAPM analyses results in a cost of equity range of 9.32 percent to 11.48 percent with a midpoint of 10.40 percent.[71]

**Figure 8: Summary of Adjustments to Ms. Reno's CAPM Analysis**

| | **Historical MRP** | **Supply-Side MRP** | **Kroll Recommended MRP** | **Range** | **Midpoint** |
|---|---|---|---|---|---|
| As Filed | 11.44% | 10.55% | 8.20% | 8.20% to 11.44% | 9.82% |
| As Adjusted (Kroll MRP - Spot Yield / Hist. MRP & S.S. MRP (1926-2024) | 11.57% | 10.58% | 9.25% | 9.25% to 11.57% | 10.41% |
| As Updated (As of March 31, 2025) | 11.48% | 10.49% | 9.32% | 9.32% to 11.48% | 10.40% |

**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 9 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 CMW-3R and Exhibit CMW-4R, respectively. As shown in Figure 9, the midpoint of Ms. Reno's constant growth DCF analyses increases from 9.39 percent to 10.17 percent while the midpoint of her CAPM analyses increases from 9.82 percent to 10.40 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

[71] 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 9.75 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.

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 10.29 percent – which is significantly higher than the Company's requested ROE of 9.75 percent in this proceeding.

**Figure 9: Summary of Adjusted Cost of Equity Results**

| | As Filed | Adjusted/ Corrected | Updated/ Adjusted/ Corrected |
|---|---|---|---|
| **Constant Growth DCF** | | | |
| **30-Day Avg.** | | | |
| Proj. EPS Growth Rates | 10.22% | 10.22% | 10.10% |
| Proj. EPS, BVPS & DPS Growth Rates | 9.12% | Excl. | Excl. |
| Sustainable Growth Rate | 8.44% | Excl. | Excl. |
| **90-Day Avg.** | | | |
| Proj. EPS Growth Rates | 10.34% | 10.34% | 10.24% |
| Proj. EPS, BVPS & DPS Growth Rates | 9.10% | Excl. | Excl. |
| Sustainable Growth Rate | 8.50% | Excl. | Excl. |
| **Midpoint** | **9.39%** | **10.28%** | **10.17%** |
| **CAPM** | | | |
| Historical MRP | 11.44% | 11.57% | 11.48% |
| Supply-Side MRP | 10.55% | 10.58% | 10.49% |
| Kroll Recommended MRP | 8.20% | 9.25% | 9.32% |
| **Midpoint** | **9.82%** | **10.41%** | **10.40%** |
| **Average of DCF and CAPM** | **9.61%** | **10.35%** | **10.29%** |

### E. Business and Regulatory Risks

**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".[72] 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 default service charge, state tax adjustment surcharge, Distribution System Improvement Charge ("DSIC") and use of a forecast test year.[73]

**Q. What is your concern with Ms. Reno's use of the credit rating for CEC to assess the business risk of Pike's electric 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 electric 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.[74] 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 cost of equity should reflect the investor required return for Pike's electric 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

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[72] Reno Direct Testimony, at 34.

[73] *Id.,* at 37-40.

[74] Morin, Dr. Roger A. *New Regulatory Finance*. Public Utilities Reports, Inc., 2006, at 215-216.

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 electric 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 BBB+ from S&P and Baa2 from Moody's, [75] 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 regulatory mechanisms such as the use of a forecast test year, DSIC, default service charge, and state tax adjustment surcharge?**

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 fundamental comparison here is to the proxy group". [76] 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". [77]

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[75] Reno Direct Testimony, at 35.

[76] *Id.*

[77] *Id.,* at 38.

**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-5R and summarized below:

- Fuel Cost Recovery: The Company has the default service charge to recover the cost of purchasing energy, capacity and ancillary services for default service customers, which is updated every six months and also allows for the variances between actual costs and projected costs to be recovered from or refunded to customers. Similarly, as shown in Exhibit CMW-5R, approximately 92.65 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 58.82 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: Pike does not have protection against volumetric risk in Pennsylvania, either through a revenue decoupling mechanism, formula rate plan or straight fixed-variable rate design. However, approximately 58.82 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 electric infrastructure. Similarly, approximately 74.26 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, many of the companies in Ms. Reno's proxy group have more timely cost recovery between rate proceedings than Pike has in Pennsylvania. As a result, I conclude that the Company has slightly greater than average regulatory risk relative to Ms. Reno's proxy group.

**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.[78]

**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 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 electric operations in Pennsylvania compare in size to the companies in Ms. Reno's proxy group?**

A. The Company's electric 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-6R, Pike's common equity based on its

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[78] Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

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.[79] As shown in Exhibit CMW-6R, the median market capitalization of the proxy group is approximately $22.75 billion, which corresponds to the second decile of *Kroll's* market capitalization data.[80] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.33 percent (*i.e.*, 33 basis points). In comparison, Pike's common equity of approximately 19.72 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 414 basis points (*i.e.*, 4.47 percent minus 0.33 percent).

**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.[81]

**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

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[79] *Kroll*, Cost of Capital Navigator – Size Premium: Annual data as of 12/21/2024.

[80] *Id*.

[81] Duff & Phelps, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

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.[82] 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.[83]

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.[84] 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.[85]

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[82] 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.

[83] *Id*.

[84] 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.

[85] 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.

**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." [86] 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.[87] 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, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[88] 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.[89]

Additionally, in Docket No. E017/GR-15-1033 for Otter Tail Power Company ("Otter Tail"), the Minnesota Public Utilities Commission ("Minnesota PUC") selected an

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[86] 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.

[87] *Id.*, at 32 and 37.

[88] 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.

[89] *Id.*

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.[90]

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 necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[91]

**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. As discussed, I conclude that the Company has slightly greater than average regulatory risk relative to Ms. Reno's proxy group. Further, the Company has substantial risk associated with the small size of its electric 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 either compare the regulatory mechanisms of the Company to the regulatory

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[90] 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.

[91] 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).

mechanisms of the proxy group companies nor 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. Capital Structure

**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 50.52 percent common equity, 40.81 percent long-term debt, and 8.66 percent short-term debt but recommends that Pike's equity ratio of 50.52 percent be "established as a maximum".[92] Ms. Reno suggests that her recommendation to establish a "maximum" equity ratio of 50.52 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.

[92] Reno Direct Testimony, at 24-25.

**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 electric 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-7R, 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 51.89 percent. Therefore, Pike's proposed equity ratio of 50.52 percent is 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 50.52 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.[93] As shown in Equation [1], the value of a company (or asset) is determined as follows:

$$V = D + E \qquad [1]$$

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:

$$r_V = \frac{D}{D + E} \text{ x } r_D + \frac{E}{E + D} \text{ x } r_E \qquad [2]$$

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

93 Brealey, Myers, and Allen, *Principles of Corporate Finance,* 13th Ed., 2020, at 452-462.

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-8R presents the average market value common equity ratio for Ms. Reno's proxy group as of December 31, 2024.[94] As shown therein, the median common equity ratio for Ms. Reno's proxy group is 55.39 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 55.39 percent. Based on this analysis, the market value common equity ratio is significantly greater than the median book value equity ratio of 43.50 percent that Ms. Reno relied on to benchmark the Company's proposed equity ratio of 50.52 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 50.52 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

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94 Note, this represents the data most currently available at the time of the preparation of my rebuttal testimony.

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 electric 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 cases for vertically integrated electric utilities; however, only T&D cases should be included due to the different risk profile of vertically integrated electric utilities, which own generation assets.
- 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 electric utilities. Ms. Reno does not consider the range of equity ratios that have been authorized for electric utilities.

**Q. Did you compare the Company's proposed equity ratio with the equity ratios that have been authorized for T&D electric utilities from 2020 through 2024?**

A. Yes. Specifically, I reviewed the authorized equity ratios for electric utilities across the U.S. from 2020 through 2024, excluding vertically integrated electric cases, 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 10, Pike's proposed equity ratio of 50.52 percent is generally consistent with the mean equity ratio for T&D electric utilities across the U.S. from 2020-2024 and well below the high-end which ranged from 53.00 to 55.00 percent. Therefore, Ms. Reno's recommendation to set the maximum equity ratio for Pike at 50.52 percent is also not supported by a review of authorized equity ratios for T&D electric utilities across the U.S.

**Figure 10: Range of Annual Authorized Equity Ratios for T&D Electric Utilities, 2020-2024**[95]

| Year | Average | Min. | Max. |
|---|---|---|---|
| 2020 | 49.22% | 42.50% | 54.40% |
| 2021 | 50.34% | 48.51% | 54.43% |
| 2022 | 50.61% | 48.00% | 53.87% |
| 2023 | 49.23% | 42.50% | 53.00% |
| 2024 | 50.44% | 42.50% | 55.00% |

**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.[96] 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

95 S&P Capital IQ Pro.

96 *See, e.g.*, Dr. Roger A. Morin, *Modern Regulatory Finance*, Public Utilities Reports, Inc., 2021, Chapter 20.

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.

**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.[97]

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

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[97] Richard A. Brealey, Stewart C. Myers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 8th Ed., 2006, at 234.

> 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.[98]

Finally, the use of double leverage versus an independent capital structure was studied by Pettway and Jordan (1983)[99] and Lerner (1973).[100] 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

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98 Alan C. Shapiro, Modern Corporate Finance, Wiley, 1st Ed., 1990, at 276.

99 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.

100 Eugene M. Lerner, "What are the Real Double Leverage Problems," Public Utilities Reports, Inc., June 7, 1973.

> regulation. The analysis finds no valid support for the "double leverage" approach; the "independent company" approach is shown to be universally correct.[101]

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.[102]

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[101] *Id.*

[102] Eugene M. Lerner, "What are the Real Double Leverage Problems," Public Utilities Reports, Inc., June 7, 1973, at 22.

**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 50.52 percent results in greater leverage on average than the proxy group measured using data at both the holding company and 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 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

Boston | +1.508.450.7361 | Chris.Wall@brattle.com

### 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 OTTER TAIL CORPORATION**

**Otter Tail Corporation - Operating Income ($000)**

| Year | Total | Electric | Manufacturing | Plastics | Corporate and Intersegment Eliminations | Notes | Percent Reg / Total |
|---|---|---|---|---|---|---|---|
| 2024 | 380,250 | 113,789 | 19,092 | 271,905 | (24,536) | [1] | 29.92% |
| 2023 | 377,919 | 106,521 | 29,140 | 254,402 | (12,144) | [1] | 28.19% |
| 2022 | 390,439 | 113,138 | 29,065 | 264,578 | (16,342) | [1] | 28.98% |
| **3 yr. average** | | | | | | | **29.03%** |

**Notes:**
[1] Source: OTTR - 2024 Form 10-K, pp. 50, 60 and 61

MS. RENO - 30-DAY AVG. PRICE - CONSTANT GROWTH DCF - AS FILED

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | Dividend Yield | Expected Dividend Yield | Value Line Projected EPS Growth Rate | S&P Capital IQ Projected EPS Growth Rate | Zacks Projected EPS Growth Rate | Average Projected EPS Growth Rate | Cost of Equity |
| Alliant Energy Corporation | LNT | $2.04 | $60.97 | 3.35% | 3.45% | 6.00% | 6.73% | 6.40% | 6.38% | 9.83% |
| Ameren Corporation | AEE | $2.85 | $97.19 | 2.93% | 3.03% | 6.50% | 6.82% | 6.70% | 6.67% | 9.70% |
| American Electric Power Company, Inc. | AEP | $3.80 | $101.92 | 3.73% | 3.85% | 6.50% | 6.59% | 6.00% | 6.36% | 10.21% |
| Avista Corporation | AVA | $2.00 | $37.36 | 5.35% | 5.51% | 5.50% | 5.74% | 5.90% | 5.71% | 11.22% |
| CMS Energy Corporation | CMS | $2.20 | $69.25 | 3.18% | 3.29% | 6.00% | 7.27% | 7.70% | 6.99% | 10.28% |
| Consolidated Edison, Inc. | ED | $3.40 | $96.29 | 3.53% | 3.63% | 6.00% | 5.71% | 5.60% | 5.77% | 9.40% |
| Dominion Resources, Inc. | D | $2.67 | $55.81 | 4.78% | 5.04% | 3.50% | 15.54% | 13.60% | 10.88% | 15.92% |
| DTE Energy Company | DTE | $4.41 | $126.16 | 3.50% | 3.61% | 4.50% | 7.59% | 7.60% | 6.56% | 10.17% |
| Duke Energy Corporation | DUK | $4.22 | $114.04 | 3.70% | 3.82% | 6.00% | 6.33% | 6.30% | 6.21% | 10.03% |
| Edison International | EIX | $3.36 | $52.05 | 6.46% | 6.71% | 6.50% | 8.25% | 8.50% | 7.75% | 14.46% |
| Entergy Corporation | ETR | $2.43 | $83.48 | 2.91% | 3.01% | 3.00% | 8.88% | 9.50% | 7.13% | 10.14% |
| Eversource Energy | ES | $3.03 | $60.72 | 4.99% | 5.13% | 5.50% | 5.86% | 5.70% | 5.69% | 10.82% |
| Evergy, Inc. | EVRG | $2.71 | $66.32 | 4.09% | 4.21% | 7.50% | 5.66% | 5.70% | 6.29% | 10.50% |
| Exelon Corporation | EXC | $1.62 | $42.10 | 3.85% | 3.96% | n/a | 5.86% | 5.70% | 5.78% | 9.74% |
| FirstEnergy Corporation | FE | $1.80 | $40.63 | 4.43% | 4.57% | 5.50% | 6.70% | 6.90% | 6.37% | 10.94% |
| IDACORP, Inc. | IDA | $3.52 | $111.75 | 3.15% | 3.27% | 6.00% | 7.81% | 8.50% | 7.44% | 10.70% |
| MGE Energy, Inc. | MGEE | $1.95 | $90.60 | 2.15% | 2.23% | 7.00% | n/a | n/a | 7.00% | 9.23% |
| NextEra Energy, Inc. | NEE | $2.26 | $69.96 | 3.23% | 3.36% | 8.50% | 7.65% | 7.80% | 7.98% | 11.34% |
| NorthWestern Corporation | NWE | $2.64 | $53.78 | 4.91% | 5.04% | 4.50% | 5.76% | 6.10% | 5.45% | 10.50% |
| OGE Energy Corporation | OGE | $1.71 | $43.56 | 3.93% | 4.05% | 6.50% | 5.92% | 6.10% | 6.17% | 10.22% |
| Otter Tail Corporation | OTTR | $2.10 | $79.35 | 2.65% | 2.73% | 4.50% | 8.20% | n/a | 6.35% | 9.08% |
| Pinnacle West Capital Corporation | PNW | $3.61 | $89.14 | 4.05% | 4.16% | 4.00% | 6.42% | 5.60% | 5.34% | 9.50% |
| TXNM Energy | TXNM | $1.65 | $50.09 | 3.29% | 3.37% | 4.00% | 6.00% | 3.00% | 4.33% | 7.70% |
| Portland General Electric Company | POR | $2.08 | $42.36 | 4.91% | 5.11% | 5.50% | 6.87% | 12.30% | 8.22% | 13.34% |
| PPL Corporation | PPL | $1.09 | $34.16 | 3.19% | 3.31% | 7.50% | 7.27% | 6.80% | 7.19% | 10.50% |
| Public Service Enterprise Group Inc. | PEG | $2.56 | $83.68 | 3.06% | 3.16% | 6.00% | 6.58% | 7.20% | 6.59% | 9.75% |
| Southern Company | SO | $2.96 | $86.03 | 3.44% | 3.55% | 6.50% | 6.62% | 6.80% | 6.64% | 10.19% |
| Xcel Energy Inc. | XEL | $2.30 | $68.29 | 3.37% | 3.48% | 6.50% | 7.35% | 6.90% | 6.92% | 10.40% |
| Mean | | | | 3.79% | 3.92% | 5.76% | 7.11% | 7.11% | 6.65% | 10.56% |
| Median | | | | 3.51% | 3.62% | 6.00% | 6.70% | 6.75% | 6.47% | 10.22% |

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

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | Dividend Yield | Expected Dividend Yield | Value Line Projected EPS Growth Rate | S&P Capital IQ Projected EPS Growth Rate | Zacks Projected EPS Growth Rate | Average Projected EPS Growth Rate | Cost of Equity |
| Alliant Energy Corporation | LNT | $2.04 | $63.22 | 3.23% | 3.33% | 6.00% | 6.81% | 6.70% | 6.50% | 9.84% |
| Ameren Corporation | AEE | $2.85 | $98.98 | 2.88% | 2.98% | 6.50% | 6.88% | 6.70% | 6.69% | 9.67% |
| American Electric Power Company, Inc. | AEP | $3.80 | $105.19 | 3.61% | 3.73% | 6.50% | 6.69% | 6.30% | 6.50% | 10.23% |
| Avista Corporation | AVA | $2.00 | $39.81 | 5.02% | 5.17% | 5.50% | 5.88% | 6.10% | 5.83% | 11.00% |
| CMS Energy Corporation | CMS | $2.20 | $73.07 | 3.01% | 3.12% | 6.00% | 7.27% | 7.70% | 6.99% | 10.11% |
| Consolidated Edison, Inc. | ED | $3.40 | $105.77 | 3.21% | 3.31% | 6.00% | 5.91% | 5.60% | 5.84% | 9.15% |
| Dominion Resources, Inc. | D | $2.67 | $54.71 | 4.88% | 5.13% | 3.50% | 13.49% | 13.60% | 10.20% | 15.33% |
| DTE Energy Company | DTE | $4.41 | $133.89 | 3.29% | 3.40% | 4.50% | 7.87% | 7.60% | 6.66% | 10.06% |
| Duke Energy Corporation | DUK | $4.22 | $118.27 | 3.57% | 3.68% | 6.00% | 6.32% | 6.30% | 6.21% | 9.88% |
| Edison International | EIX | $3.36 | $57.11 | 5.88% | 6.11% | 6.50% | 7.74% | 8.50% | 7.58% | 13.69% |
| Entergy Corporation | ETR | $2.43 | $83.83 | 2.90% | 3.00% | 3.00% | 8.88% | 9.50% | 7.13% | 10.13% |
| Eversource Energy | ES | $3.03 | $60.69 | 4.99% | 5.13% | 5.50% | 5.54% | 5.70% | 5.58% | 10.71% |
| Evergy, Inc. | EVRG | $2.71 | $66.97 | 4.05% | 4.17% | 7.50% | 5.72% | 5.70% | 6.31% | 10.48% |
| Exelon Corporation | EXC | $1.62 | $43.91 | 3.69% | 3.80% | NMF | 5.86% | 5.70% | 5.78% | 9.58% |
| FirstEnergy Corporation | FE | $1.80 | $39.24 | 4.59% | 4.73% | 5.50% | 5.74% | 6.90% | 6.05% | 10.77% |
| IDACORP, Inc. | IDA | $3.52 | $114.96 | 3.06% | 3.18% | 6.00% | 8.23% | 8.50% | 7.58% | 10.76% |
| MGE Energy, Inc. | MGEE | $1.95 | $91.73 | 2.13% | 2.20% | 7.00% | n/a | n/a | 7.00% | 9.20% |
| NextEra Energy, Inc. | NEE | $2.26 | $71.44 | 3.16% | 3.29% | 8.50% | 7.11% | 7.80% | 7.80% | 11.09% |
| NorthWestern Corporation | NWE | $2.64 | $55.57 | 4.75% | 4.88% | 4.50% | 5.94% | 6.10% | 5.51% | 10.40% |
| OGE Energy Corporation | OGE | $1.71 | $44.86 | 3.81% | 3.93% | 6.50% | 5.92% | 6.10% | 6.17% | 10.10% |
| Otter Tail Corporation | OTTR | $2.10 | $81.26 | 2.58% | 2.67% | 4.50% | 8.20% | n/a | 6.35% | 9.02% |
| Pinnacle West Capital Corporation | PNW | $3.61 | $92.83 | 3.89% | 3.96% | 4.00% | 5.55% | 2.10% | 3.88% | 7.85% |
| TXNM Energy | TXNM | $1.65 | $52.26 | 3.16% | 3.23% | 4.00% | 6.55% | 3.00% | 4.52% | 7.74% |
| Portland General Electric Company | POR | $2.08 | $43.80 | 4.75% | 4.87% | 5.50% | 6.54% | 3.40% | 5.15% | 10.02% |
| PPL Corporation | PPL | $1.09 | $34.67 | 3.14% | 3.26% | 7.50% | 7.27% | 6.80% | 7.19% | 10.45% |
| Public Service Enterprise Group Inc. | PEG | $2.56 | $81.03 | 3.16% | 3.26% | 6.00% | 6.56% | 7.20% | 6.59% | 9.85% |
| Southern Company | SO | $2.96 | $89.99 | 3.29% | 3.40% | 6.50% | 6.33% | 6.50% | 6.44% | 9.84% |
| Xcel Energy Inc. | XEL | $2.30 | $69.13 | 3.33% | 3.44% | 6.50% | 7.26% | 6.90% | 6.89% | 10.33% |
| Mean | | | | 3.68% | 3.80% | 5.76% | 6.97% | 6.65% | 6.46% | 10.26% |
| Median | | | | 3.31% | 3.42% | 6.00% | 6.56% | 6.60% | 6.47% | 10.10% |

Notes:
[1] Value Line
[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

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | Dividend Yield | Expected Dividend Yield | Value Line Projected EPS Growth Rate | S&P Capital IQ Projected EPS Growth Rate | Zacks Projected EPS Growth Rate | Average Growth Rate | Cost of Equity |
| Alliant Energy Corporation | LNT | $2.04 | $60.00 | 3.40% | 3.51% | 6.00% | 6.73% | 6.40% | 6.38% | 9.89% |
| Ameren Corporation | AEE | $2.85 | $93.02 | 3.06% | 3.17% | 6.50% | 6.82% | 6.70% | 6.67% | 9.84% |
| American Electric Power Company, Inc. | AEP | $3.80 | $97.12 | 3.91% | 4.04% | 6.50% | 6.59% | 6.00% | 6.36% | 10.40% |
| Avista Corporation | AVA | $2.00 | $36.85 | 5.43% | 5.58% | 5.50% | 5.74% | 5.90% | 5.71% | 11.30% |
| CMS Energy Corporation | CMS | $2.20 | $67.63 | 3.25% | 3.37% | 6.00% | 7.27% | 7.70% | 6.99% | 10.36% |
| Consolidated Edison, Inc. | ED | $3.40 | $93.22 | 3.65% | 3.75% | 6.00% | 5.71% | 5.60% | 5.77% | 9.52% |
| Dominion Resources, Inc. | D | $2.67 | $54.91 | 4.86% | 5.13% | 3.50% | 15.54% | 13.60% | 10.88% | 16.01% |
| DTE Energy Company | DTE | $4.41 | $122.75 | 3.59% | 3.71% | 4.50% | 7.59% | 7.60% | 6.56% | 10.27% |
| Duke Energy Corporation | DUK | $4.22 | $110.90 | 3.81% | 3.92% | 6.00% | 6.33% | 6.30% | 6.21% | 10.13% |
| Edison International | EIX | $3.36 | $66.20 | 5.08% | 5.27% | 6.50% | 8.25% | 8.50% | 7.75% | 13.02% |
| Entergy Corporation | ETR | $2.43 | $79.20 | 3.07% | 3.18% | 3.00% | 8.88% | 9.50% | 7.13% | 10.30% |
| Eversource Energy | ES | $3.03 | $58.97 | 5.14% | 5.28% | 5.50% | 5.86% | 5.70% | 5.69% | 10.97% |
| Evergy, Inc. | EVRG | $2.71 | $63.56 | 4.26% | 4.40% | 7.50% | 5.66% | 5.70% | 6.29% | 10.68% |
| Exelon Corporation | EXC | $1.62 | $39.42 | 4.11% | 4.23% | n/a | 5.86% | 5.70% | 5.78% | 10.01% |
| FirstEnergy Corporation | FE | $1.80 | $40.19 | 4.48% | 4.62% | 5.50% | 6.70% | 6.90% | 6.37% | 10.99% |
| IDACORP, Inc. | IDA | $3.52 | $111.04 | 3.17% | 3.29% | 6.00% | 7.81% | 8.50% | 7.44% | 10.72% |
| MGE Energy, Inc. | MGEE | $1.95 | $93.09 | 2.09% | 2.17% | 7.00% | n/a | n/a | 7.00% | 9.17% |
| NextEra Energy, Inc. | NEE | $2.26 | $71.27 | 3.17% | 3.30% | 8.50% | 7.65% | 7.80% | 7.98% | 11.28% |
| NorthWestern Corporation | NWE | $2.64 | $53.26 | 4.96% | 5.09% | 4.50% | 5.76% | 6.10% | 5.45% | 10.55% |
| OGE Energy Corporation | OGE | $1.71 | $42.39 | 4.03% | 4.16% | 6.50% | 5.92% | 6.10% | 6.17% | 10.33% |
| Otter Tail Corporation | OTTR | $2.10 | $77.54 | 2.71% | 2.79% | 4.50% | 8.20% | n/a | 6.35% | 9.14% |
| Pinnacle West Capital Corporation | PNW | $3.61 | $87.40 | 4.13% | 4.24% | 4.00% | 6.42% | 5.60% | 5.34% | 9.58% |
| TXNM Energy | TXNM | $1.65 | $48.90 | 3.37% | 3.45% | 4.00% | 6.00% | 3.00% | 4.33% | 7.78% |
| Portland General Electric Company | POR | $2.08 | $43.10 | 4.83% | 5.02% | 5.50% | 6.87% | 12.30% | 8.22% | 13.25% |
| PPL Corporation | PPL | $1.09 | $33.21 | 3.28% | 3.40% | 7.50% | 7.27% | 6.80% | 7.19% | 10.59% |
| Public Service Enterprise Group Inc. | PEG | $2.56 | $85.46 | 3.00% | 3.09% | 6.00% | 6.58% | 7.20% | 6.59% | 9.69% |
| Southern Company | SO | $2.96 | $84.27 | 3.51% | 3.63% | 6.50% | 6.62% | 6.80% | 6.64% | 10.27% |
| Xcel Energy Inc. | XEL | $2.30 | $67.73 | 3.40% | 3.51% | 6.50% | 7.35% | 6.90% | 6.92% | 10.43% |
| Mean | | | | 3.81% | 3.94% | 5.76% | 7.11% | 7.11% | 6.65% | 10.59% |
| Median | | | | 3.62% | 3.73% | 6.00% | 6.70% | 6.75% | 6.47% | 10.34% |

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

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | | Annualized Dividend | Stock Price | Dividend Yield | Expected Dividend Yield | Value Line Projected EPS Growth Rate | S&P Capital IQ Projected EPS Growth Rate | Zacks Projected EPS Growth Rate | Average Growth Rate | Cost of Equity |
| Alliant Energy Corporation | LNT | $2.04 | $61.00 | 3.34% | 3.45% | 6.00% | 6.81% | 6.70% | 6.50% | 9.96% |
| Ameren Corporation | AEE | $2.85 | $95.78 | 2.98% | 3.08% | 6.50% | 6.88% | 6.70% | 6.69% | 9.77% |
| American Electric Power Company, Inc. | AEP | $3.80 | $100.92 | 3.77% | 3.89% | 6.50% | 6.69% | 6.30% | 6.50% | 10.39% |
| Avista Corporation | AVA | $2.00 | $37.67 | 5.31% | 5.46% | 5.50% | 5.88% | 6.10% | 5.83% | 11.29% |
| CMS Energy Corporation | CMS | $2.20 | $69.58 | 3.16% | 3.27% | 6.00% | 7.27% | 7.70% | 6.99% | 10.26% |
| Consolidated Edison, Inc. | ED | $3.40 | $97.65 | 3.48% | 3.58% | 6.00% | 5.91% | 5.60% | 5.84% | 9.42% |
| Dominion Resources, Inc. | D | $2.67 | $54.59 | 4.89% | 5.14% | 3.50% | 13.49% | 13.60% | 10.20% | 15.34% |
| DTE Energy Company | DTE | $4.41 | $126.77 | 3.48% | 3.59% | 4.50% | 7.87% | 7.60% | 6.66% | 10.25% |
| Duke Energy Corporation | DUK | $4.22 | $113.50 | 3.72% | 3.83% | 6.00% | 6.32% | 6.30% | 6.21% | 10.04% |
| Edison International | EIX | $3.36 | $57.43 | 5.85% | 6.07% | 6.50% | 7.74% | 8.50% | 7.58% | 13.65% |
| Entergy Corporation | ETR | $2.43 | $82.11 | 2.96% | 3.06% | 3.00% | 8.88% | 9.50% | 7.13% | 10.19% |
| Eversource Energy | ES | $3.03 | $59.19 | 5.12% | 5.26% | 5.50% | 5.54% | 5.70% | 5.58% | 10.84% |
| Evergy, Inc. | EVRG | $2.71 | $64.96 | 4.17% | 4.30% | 7.50% | 5.72% | 5.70% | 6.31% | 10.61% |
| Exelon Corporation | EXC | $1.62 | $41.59 | 3.90% | 4.01% | NMF | 5.86% | 5.70% | 5.78% | 9.79% |
| FirstEnergy Corporation | FE | $1.80 | $39.65 | 4.54% | 4.68% | 5.50% | 5.74% | 6.90% | 6.05% | 10.72% |
| IDACORP, Inc. | IDA | $3.52 | $111.78 | 3.15% | 3.27% | 6.00% | 8.23% | 8.50% | 7.58% | 10.85% |
| MGE Energy, Inc. | MGEE | $1.95 | $90.71 | 2.15% | 2.23% | 7.00% | n/a | n/a | 7.00% | 9.23% |
| NextEra Energy, Inc. | NEE | $2.26 | $70.22 | 3.22% | 3.34% | 8.50% | 7.11% | 7.80% | 7.80% | 11.15% |
| NorthWestern Corporation | NWE | $2.64 | $53.86 | 4.90% | 5.04% | 4.50% | 5.94% | 6.10% | 5.51% | 10.55% |
| OGE Energy Corporation | OGE | $1.71 | $43.50 | 3.93% | 4.05% | 6.50% | 5.92% | 6.10% | 6.17% | 10.22% |
| Otter Tail Corporation | OTTR | $2.10 | $78.93 | 2.66% | 2.75% | 4.50% | 8.20% | n/a | 6.35% | 9.10% |
| Pinnacle West Capital Corporation | PNW | $3.61 | $88.98 | 4.06% | 4.14% | 4.00% | 5.55% | 2.10% | 3.88% | 8.02% |
| TXNM Energy | TXNM | $1.65 | $50.06 | 3.30% | 3.37% | 4.00% | 6.55% | 3.00% | 4.52% | 7.89% |
| Portland General Electric Company | POR | $2.08 | $42.44 | 4.90% | 5.03% | 5.50% | 6.54% | 3.40% | 5.15% | 10.17% |
| PPL Corporation | PPL | $1.09 | $33.71 | 3.23% | 3.35% | 7.50% | 7.27% | 6.80% | 7.19% | 10.54% |
| Public Service Enterprise Group Inc. | PEG | $2.56 | $82.94 | 3.09% | 3.19% | 6.00% | 6.56% | 7.20% | 6.59% | 9.77% |
| Southern Company | SO | $2.96 | $86.21 | 3.43% | 3.54% | 6.50% | 6.33% | 6.50% | 6.44% | 9.99% |
| Xcel Energy Inc. | XEL | $2.30 | $67.61 | 3.40% | 3.52% | 6.50% | 7.26% | 6.90% | 6.89% | 10.41% |
| Mean | | | | 3.79% | 3.91% | 5.76% | 6.97% | 6.65% | 6.46% | 10.37% |
| Median | | | | 3.48% | 3.59% | 6.00% | 6.56% | 6.60% | 6.47% | 10.24% |

Notes:
[1] Value Line
[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] | 0.94 | 0.94 | 0.94 |
| Market Risk Premium | [3] | 7.17% | 7.31% | 7.31% |
| **Cost of Equity** | [4] | **11.44%** | **11.57%** | **11.48%** |
| *Increase from As-Filed:* | | | ***0.13%*** | ***0.04%*** |

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] | 0.94 | 0.94 | 0.94 |
| Market Risk Premium | [3] | 6.22% | 6.26% | 6.26% |
| **Cost of Equity** | [4] | **10.55%** | **10.58%** | **10.49%** |
| *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] | 0.94 | 0.94 | 0.94 |
| Market Risk Premium | [3] | 5.00% | 5.00% | 5.00% |
| **Cost of Equity** | [4] | **8.20%** | **9.25%** | **9.32%** |
| *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 | | | | | |
| Company | Operating Subsidiary | State | Utility Type | Test Year Convention | Revenue Decoupling | Formula-Based Rates | Straight Fixed Variable Rate Design | Overall Revenue Stabilization | Capital Cost Recovery | Fuel Adjustment Clause |
| Alliant Energy Corporation | Interstate Power & Light Co. | Iowa | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Interstate Power & Light Co. | Iowa | Gas | Fully Forecast | No | No | No | No | No | Yes |
| | Wisconsin Power & Light Co. | Wisconsin | Electric | Fully Forecast | No | No | No | No | No | Yes |
| | Wisconsin Power & Light Co. | Wisconsin | Gas | Fully Forecast | No | No | No | No | No | Yes |
| Ameren Corporation | Ameren Illinois Co. | Illinois | Electric | Fully Forecast | Yes | No | No | Yes | Yes | n/a |
| | Ameren Illinois Co. | Illinois | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Union Electric Co. | Missouri | Electric | Historical | Yes | No | No | Yes | Yes | Yes w/ sharing |
| | Union Electric Co. | Missouri | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| American Electric Power Company, Inc. | Southwestern Electric Power Co. | Arkansas | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| | Indiana Michigan Power Co. | Indiana | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Kentucky Power Co. | Kentucky | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Southwestern Electric Power Co. | Louisiana | Electric | Historical | Yes | Yes | No | Yes | No | Yes |
| | Indiana Michigan Power Co. | Michigan | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Ohio Power Co. | Ohio | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| | Public Service Co. of Oklahoma | Oklahoma | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| | Kingsport Power Co. | Tennessee | Electric | Historical | No | No | No | No | No | Yes |
| | AEP Texas | Texas | Electric | Historical | No | No | No | No | Yes | n/a |
| | Southwestern Electric Power Co. | Texas | Electric | Historical | No | No | No | No | Yes | Yes |
| | Appalachian Power Co. | Virginia | Electric | Historical | No | No | No | No | Yes | Yes |
| | Appalachian Power Co./Wheeling Power Co. | West Virginia | Electric | Historical | No | No | No | No | Yes | Yes |
| Avista Corporation | Alaska Electric Light and Power Co. | Alaska | Electric | Historical | No | No | No | No | No | Yes |
| | Avista Corp. | Idaho | Electric | Historical | Yes | No | No | Yes | No | Yes w/ sharing |
| | Avista Corp. | Idaho | Gas | Historical | Yes | No | No | Yes | No | Yes |
| | Avista Corp. | Oregon | Gas | Fully Forecast | Yes | No | No | Yes | No | Yes w/ sharing |
| | Avista Corp. | Washington | Electric | Historical | Yes | No | No | Yes | No | Yes w/ sharing |
| | Avista Corp. | Washington | Gas | Historical | Yes | No | No | Yes | No | Yes |
| CMS Energy Corporation | Consumers Energy Co. | Michigan | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Consumers Energy Co. | Michigan | Gas | Fully Forecast | Yes | No | No | Yes | No | Yes |
| Consolidated Edison, Inc. | Consolidated Edison Co. of New York, Inc. | New York | Electric | Fully Forecast | Yes | No | No | Yes | Yes | n/a |
| | Consolidated Edison Co. of New York, Inc. | New York | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Orange & Rockland Utilities, Inc. | New York | Electric | Fully Forecast | Yes | No | No | Yes | Yes | n/a |
| | Orange & Rockland Utilities, Inc. | New York | Gas | Fully Forecast | Yes | No | No | Yes | No | Yes |
| | Rockland Electric Co. | New Jersey | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| Dominion Resources, Inc. | Dominion Energy Virginia | North Carolina | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| | Dominion Energy South Carolina | South Carolina | Electric | Historical | No | No | No | No | Yes | Yes |
| | Dominion Energy South Carolina | South Carolina | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| | Dominion Energy Virginia | Virginia | Electric | Partially Forecast | No | No | No | No | Yes | Yes |
| DTE Energy Company | DTE Electric Co. | Michigan | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | DTE Gas Co. | Michigan | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| Duke Energy Corporation | Duke Energy Florida LLC | Florida | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Duke Energy Indiana LLC | Indiana | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Duke Energy Kentucky Inc. | Kentucky | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Duke Energy Kentucky Inc. | Kentucky | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Duke Energy Carolinas LLC/Duke Energy Progress LLC | North Carolina | Electric | Historical | No | No | No | No | Yes | Yes |
| | Piedmont Natural Gas Co. Inc. | North Carolina | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| | Duke Energy Ohio Inc. | Ohio | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| | Duke Energy Ohio Inc. | Ohio | Gas | Partially Forecast | No | No | Yes | Yes | Yes | Yes |
| | Duke Energy Carolinas LLC/Duke Energy Progress LLC | South Carolina | Electric | Historical | No | No | No | No | Yes | Yes |
| | Piedmont Natural Gas Co. Inc. | South Carolina | Gas | Historical | Yes | No | No | Yes | No | Yes |
| | Piedmont Natural Gas Co. Inc. | Tennessee | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| Edison International | Southern California Edison Co. | California | Electric | Fully Forecast | Yes | No | No | Yes | No | Yes |
| Entergy Corporation | Entergy Arkansas LLC | Arkansas | Electric | Fully Forecast | Yes | Yes | No | Yes | Yes | Yes |
| | Entergy New Orleans LLC | Louisiana-NOCC | Electric | Partially Forecast | No | Yes | No | Yes | Yes | Yes |
| | Entergy New Orleans LLC | Louisiana-NOCC | Gas | Partially Forecast | No | Yes | No | Yes | No | Yes |
| | Entergy Louisiana LLC | Louisiana | Electric | Historical | Yes | Yes | No | Yes | Yes | Yes |
| | Entergy Louisiana LLC | Louisiana | Gas | Historical | No | Yes | No | Yes | Yes | Yes |
| | Entergy Mississippi LLC | Mississippi | Electric | Fully Forecast | Yes | Yes | No | Yes | No | Yes |
| | Entergy Texas Inc. | Texas | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| Eversource Energy | Connecticut Light and Power Co. | Connecticut | Electric | Fully Forecast | Yes | No | No | Yes | Yes | n/a |
| | Yankee Gas Services Co. | Connecticut | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Eversource Gas Co. of Massachusetts | Massachusetts | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| | NSTAR Electric Co. | Massachusetts | Electric | Historical | Yes | Yes | No | Yes | Yes | n/a |
| | NSTAR Gas Co. | Massachusetts | Electric | Historical | Yes | Yes | No | Yes | Yes | Yes |
| | Public Service Co. of New Hampshire | New Hampshire | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| Evergy, Inc. | Evergy Kansas Central Inc | Kansas | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| | Evergy Metro Inc. | Kansas | Electric | Historical | No | No | No | No | Yes | Yes |
| | Evergy Metro Inc | Missouri | Electric | Historical | Yes | No | No | Yes | Yes | Yes w/ sharing |
| | Evergy Missouri West Inc. | Missouri | Electric | Historical | Yes | No | No | Yes | Yes | Yes w/ sharing |
| Exelon Corporation | Delmarva Power & Light Co. | Delaware | Electric | Partially Forecast | No | No | No | No | Yes | n/a |
| | Delmarva Power & Light Co. | Delaware | Gas | Historical | No | No | No | No | Yes | Yes |
| | Potomac Electric Power Co. | District of Columbia | Electric | Fully Forecast | Yes | No | No | Yes | Yes | n/a |
| | Commonwealth Edison Co. | Illinois | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | Baltimore Gas & Electric Co. | Maryland | Electric | Fully Forecast | Yes | No | No | Yes | No | n/a |
| | Baltimore Gas & Electric Co. | Maryland | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Delmarva Power & Light Co. | Maryland | Electric | Fully Forecast | Yes | No | No | Yes | No | n/a |

**COMPARISON OF PIKE AND MS. RENO'S PROXY GROUP COMPANIES**
**REGULATORY RISK ASSESSMENT**

| Company | Operating Subsidiary | State | Utility Type | [1] Test Year Convention | [2] Revenue Stabilization: Revenue Decoupling | [3] Revenue Stabilization: Formula-Based Rates | [4] Revenue Stabilization: Straight Fixed Variable Rate Design | [5] Overall Revenue Stabilization | [6] Capital Cost Recovery | [7] Fuel Adjustment Clause |
|---|---|---|---|---|---|---|---|---|---|---|
| | Potomac Electric Power Co. | Maryland | Electric | Fully Forecast | Yes | No | No | Yes | Yes | n/a |
| | Atlantic City Electric Co. | New Jersey | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| | PECO Energy Co. | Pennsylvania | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | PECO Energy Co. | Pennsylvania | Gas | Fully Forecast | No | No | No | No | Yes | Yes |
| FirstEnergy Corporation | Potomac Edison Co. | Maryland | Electric | Historical | No | No | No | No | No | n/a |
| | Jersey Central Power & Light Co. | New Jersey | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| | Cleveland Electric Illum./Ohio Edison/Toledo Edison | Ohio | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| | Metropolitan Edison Co. | Pennsylvania | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | Pennsylvania Electric Co. | Pennsylvania | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | Pennsylvania Power Co. | Pennsylvania | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | West Penn Power Co. | Pennsylvania | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | Monongahela Power Co. | West Virginia | Electric | Historical | No | No | No | No | Yes | Yes |
| | Potomac Edison Co. | West Virginia | Electric | Historical | No | No | No | No | No | Yes |
| IDACORP, Inc. | Idaho Power Co. | Idaho | Electric | Partially Forecast | Yes | No | No | Yes | No | Yes w/ sharing |
| | Idaho Power Co. | Oregon | Electric | Partially Forecast | No | No | No | No | No | Yes w/ sharing |
| MGE Energy, Inc. | Madison Gas & Electric Co. | Wisconsin | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Madison Gas & Electric Co. | Wisconsin | Gas | Fully Forecast | No | No | No | No | No | Yes |
| NextEra Energy, Inc. | Florida Power & Light Co. | Florida | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Pivotal Utility Holdings Inc. | Florida | Gas | Fully Forecast | No | No | No | No | Yes | Yes |
| | Lone Star Transmission LLC | Texas | Electric | Historical | No | No | No | No | Yes | n/a |
| NorthWestern Corporation | NorthWestern Corporation | Montana | Electric | Historical | No | No | No | No | No | Yes w/ sharing |
| | NorthWestern Corporation | Montana | Gas | Historical | No | No | No | No | No | Yes |
| | NorthWestern Corporation | Nebraska | Gas | Historical | No | No | No | No | No | Yes |
| | NorthWestern Corporation | South Dakota | Electric | Historical | No | No | No | No | No | Yes |
| | NorthWestern Corporation | South Dakota | Gas | Historical | No | No | No | No | No | Yes |
| OGE Energy Corporation | Oklahoma Gas and Electric Company | Arkansas | Electric | Historical | Yes | Yes | No | Yes | Yes | Yes |
| | Oklahoma Gas and Electric Company | Oklahoma | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| Otter Tail Corporation | Otter Tail Power Co. | Minnesota | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Otter Tail Power Co. | North Dakota | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Otter Tail Power Co. | South Dakota | Electric | Historical | No | No | No | No | Yes | Yes |
| Pinnacle West Capital Corporation | Arizona Public Service Co. | Arizona | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| TXNM Energy | Public Service Co. of New Mexico | New Mexico | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Texas-New Mexico Power Co. | Texas | Electric | Historical | No | No | No | No | Yes | n/a |
| Portland General Electric Company | Portland General Electric Co. | Oregon | Electric | Fully Forecast | No | No | No | No | Yes | Yes w/ sharing |
| PPL Corporation | Kentucky Utilities Co. | Kentucky | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Louisville Gas & Electric Co. | Kentucky | Electric | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Louisville Gas & Electric Co. | Kentucky | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | PPL Electric Utilities Corp. | Pennsylvania | Electric | Fully Forecast | No | No | No | No | Yes | n/a |
| | Narragansett Electric Co. | Rhode Island | Electric | Historical | Yes | No | No | Yes | Yes | n/a |
| | Narragansett Electric Co. | Rhode Island | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| | Kentucky Utilities Co. | Virginia | Electric | Historical | No | No | No | No | No | Yes |
| Public Service Enterprise Group Inc. | Public Service Electric Gas | New Jersey | Electric | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| | Public Service Electric Gas | New Jersey | Gas | Partially Forecast | Yes | No | No | Yes | Yes | n/a |
| Southern Company | Alabama Power Co. | Alabama | Electric | Fully Forecast | No | Yes | No | Yes | Yes | Yes |
| | Georgia Power Co. | Georgia | Electric | Fully Forecast | No | Yes | No | Yes | Yes | Yes |
| | Atlanta Gas & Light Co. | Georgia | Gas | Fully Forecast | No | Yes | Yes | Yes | Yes | n/a |
| | Northern Illinois Gas Co. | Illinois | Gas | Fully Forecast | Yes | No | No | Yes | Yes | Yes |
| | Mississippi Power Co. | Mississippi | Electric | Fully Forecast | Yes | Yes | No | Yes | Yes | Yes |
| | Chattanooga Gas Co. | Tennessee | Gas | Historical | Yes | Yes | No | Yes | No | Yes |
| | Virginia Natural Gas Inc. | Virginia | Gas | Partially Forecast | Yes | No | No | Yes | Yes | Yes |
| Xcel Energy Inc. | Public Service Co. of Colorado | Colorado | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| | Public Service Co. of Colorado | Colorado | Gas | Historical | Yes | No | No | Yes | Yes | Yes |
| | Northern States Power Co.-Minnesota | Minnesota | Electric | Fully Forecast | Yes | Yes | No | Yes | Yes | Yes |
| | Northern States Power Co.-Minnesota | Minnesota | Gas | Fully Forecast | No | No | No | No | Yes | Yes |
| | Southwestern Public Service Co. | New Mexico | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Northern States Power Co.-Minnesota | North Dakota | Electric | Fully Forecast | No | No | No | No | Yes | Yes |
| | Northern States Power Co.-Minnesota | North Dakota | Gas | Fully Forecast | No | No | Yes | Yes | No | Yes |
| | Northern States Power Co.-Minnesota | South Dakota | Electric | Historical | Yes | No | No | Yes | Yes | Yes |
| | Southwestern Public Service Co. | Texas | Electric | Historical | No | No | No | No | No | Yes |
| | Northern States Power Co.-Wisconsin | Wisconsin | Electric | Fully Forecast | No | No | No | No | No | Yes |
| | Northern States Power Co.-Wisconsin | Wisconsin | Gas | Fully Forecast | No | No | No | No | No | Yes |

| | Test Year Convention | | Overall Revenue Stabilization | | Capital Cost Recovery | | Fuel Adjustment Clause | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Yes | 95 |
| Proxy Group Totals | Fully Forecast | 64 | | | | | Yes w/ sharing | 10 |
| | Partially Forecast | 16 | Yes | 80 | Yes | 101 | n/a | 31 |
| | Historical | 56 | No | 56 | No | 35 | No | 0 |
| | % Forecast | 58.82% | % Yes | 58.82% | % Yes | 74.26% | % Yes | 92.65% |

| Company | State | Utility Type | Test Year Convention | Revenue Decoupling | Formula-Based Rates | Straight Fixed Variable Rate Design | Overall Revenue Stabilization | Capital Cost Recovery | Fuel Adjustment Clause |
|---|---|---|---|---|---|---|---|---|---|
| Pike Country Light and Power Company [8] | Pennsylvania | Electric | Fully Forecast | No | No | No | No | 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) |
|---|---|---|
| Alliant Energy Corporation | LNT | 16.22 |
| Ameren Corporation | AEE | 26.76 |
| American Electric Power Company, Inc. | AEP | 56.00 |
| Avista Corporation | AVA | 3.15 |
| CMS Energy Corporation | CMS | 21.72 |
| Consolidated Edison, Inc. | ED | 35.93 |
| Dominion Resources, Inc. | D | 46.94 |
| DTE Energy Company | DTE | 27.71 |
| Duke Energy Corporation | DUK | 91.06 |
| Edison International | EIX | 21.46 |
| Entergy Corporation | ETR | 36.39 |
| Eversource Energy | ES | 22.52 |
| Evergy, Inc. | EVRG | 15.51 |
| Exelon Corporation | EXC | 44.04 |
| FirstEnergy Corporation | FE | 22.98 |
| IDACORP, Inc. | IDA | 6.19 |
| MGE Energy, Inc. | MGEE | 3.35 |
| NextEra Energy, Inc. | NEE | 146.20 |
| NorthWestern Corporation | NWE | 3.40 |
| OGE Energy Corporation | OGE | 9.03 |
| Otter Tail Corporation | OTTR | 3.40 |
| Pinnacle West Capital Corporation | PNW | 10.91 |
| TXNM Energy | TXNM | 4.79 |
| Portland General Electric Company | POR | 4.83 |
| PPL Corporation | PPL | 25.63 |
| Public Service Enterprise Group Inc. | PEG | 40.82 |
| Southern Company | SO | 98.12 |
| Xcel Energy Inc. | XEL | 39.98 |
| Median | | 22.75 |

| | | |
|---|---|---|
| Pike County Light and Power Company | | |
| Test Year Rate Base ($millions) | [2] | $39.03 |
| Company-Projected Common Equity Ratio | [3] | 50.52% |
| Common Equity ($millions) | [4] | $19.72 |
| Market Capitalization of Proxy Group (median) ($millions) | [5] | $22,752.44 |

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] | 19.72 | 4.47% |
| Proxy Group Market Capitalization (median) | [5] | 22,752.44 | 0.33% |
| Size Premium | | | 4.14% |

Notes:
[1] S&P Capital IQ Pro, equals 30-day average as of March 31, 2025
[2] Exhibit E-3, Summary, at 1
[3] Exhibit E-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

| Proxy Group Company | Ticker | Most Recent 3 Years (2021-2023) Common Equity Ratio | Long-Term Debt Ratio | Preferred Equity Ratio | Short-term Debt Ratio | Total Capitalization |
|---|---|---|---|---|---|---|
| Alliant Energy Corporation | LNT | 50.95% | 47.02% | 0.00% | 2.04% | 100.00% |
| Ameren Corporation | AEE | 52.15% | 44.84% | 0.54% | 2.47% | 100.00% |
| American Electric Power Company, Inc. | AEP | 47.58% | 50.45% | 0.00% | 1.98% | 100.00% |
| Avista Corporation | AVA | 47.13% | 45.84% | 0.00% | 7.03% | 100.00% |
| CMS Energy Corporation | CMS | 49.65% | 48.92% | 0.19% | 1.24% | 100.00% |
| Consolidated Edison, Inc. | ED | 45.32% | 50.02% | 0.00% | 4.66% | 100.00% |
| Dominion Energy, Inc. | D | 50.53% | 43.95% | 0.00% | 5.52% | 100.00% |
| DTE Energy Company | DTE | 49.11% | 48.51% | 0.00% | 2.38% | 100.00% |
| Duke Energy Corporation | DUK | 51.63% | 45.67% | 0.00% | 2.70% | 100.00% |
| Edison International | EIX | 39.56% | 52.04% | 4.53% | 3.87% | 100.00% |
| Entergy Corporation | ETR | 48.31% | 51.58% | 0.10% | 0.00% | 100.00% |
| Eversource Energy | ES | 54.55% | 42.20% | 0.54% | 2.72% | 100.00% |
| Evergy, Inc. | EVRG | 56.97% | 36.97% | 0.00% | 6.06% | 100.00% |
| Exelon Corporation | EXC | 52.25% | 45.72% | 0.00% | 2.03% | 100.00% |
| FirstEnergy Corporation | FE | 53.66% | 43.92% | 0.00% | 2.41% | 100.00% |
| IDACORP, Inc. | IDA | 52.93% | 47.07% | 0.00% | 0.00% | 100.00% |
| MGE Energy, Inc. | MGEE | 58.84% | 38.98% | 0.00% | 2.18% | 100.00% |
| NextEra Energy, Inc. | NEE | 59.50% | 37.47% | 0.00% | 3.04% | 100.00% |
| NorthWestern Corporation | NWE | 49.35% | 50.65% | 0.00% | 0.00% | 100.00% |
| OGE Energy Corporation | OGE | 53.91% | 45.57% | 0.00% | 0.52% | 100.00% |
| Otter Tail Corporation | OTTR | 53.71% | 43.18% | 0.00% | 3.11% | 100.00% |
| Pinnacle West Capital Corporation | PNW | 48.98% | 48.38% | 0.00% | 2.64% | 100.00% |
| TXNM Energy, Inc. | TXNM | 48.82% | 48.80% | 0.19% | 2.19% | 100.00% |
| Portland General Electric Company | POR | 44.27% | 55.08% | 0.00% | 0.65% | 100.00% |
| PPL Corporation | PPL | 55.17% | 41.99% | 0.01% | 2.84% | 100.00% |
| Public Service Enterprise Group Inc. | PEG | 54.99% | 44.55% | 0.00% | 0.45% | 100.00% |
| Southern Company | SO | 53.55% | 44.08% | 0.15% | 2.22% | 100.00% |
| Xcel Energy Inc. | XEL | 53.81% | 44.79% | 0.00% | 1.40% | 100.00% |
| Average | | 51.33% | 46.01% | 0.22% | 2.44% | |
| Median | | 51.89% | 45.69% | 0.00% | 2.30% | |
| Maximum | | 59.50% | 55.08% | 4.53% | 7.03% | |
| Minimum | | 39.56% | 36.97% | 0.00% | 0.00% | |

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of the operating subsidiaries.
[2] Electric and Natural Gas operating subsidiaries with data listed as N/A from S&P Global Market Intelligence have been excluded from the analysis.

## Market Value of the Capital Structure of Ms. Reno's Proxy Group

Expressed in ($000s)

| | | Debt | | | | | | | | | | | | Preferred Equity | | Common Equity | | Market Value | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] | [17] | [18] | [19] | [20] |
| 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 |
| Alliant Energy Corporation | LNT | $1,184,000 | $2,715,000 | $1,173,000 | ($358,000) | $558,000 | $358,000 | $8,886,000 | ######### | $9,848,000 | $9,577,000 | $271,000 | ######### | $0 | $0 | $7,004,000 | ######### | ######### | 41.16% | 0.00% | 58.84% |
| Ameren Corporation | AEE | $2,264,000 | $3,413,000 | $325,000 | ($824,000) | $1,143,000 | $824,000 | ######### | ######### | $15,933,000 | $17,579,000 | -$1,646,000 | ######### | $0 | $0 | ######### | ######### | ######### | 41.16% | 0.00% | 58.84% |
| American Electric Power Company, Inc. | AEP | $5,788,800 | ######### | $3,509,700 | ($3,710,800) | $2,523,800 | $2,523,800 | ######### | ######### | $38,964,700 | $42,642,800 | -$3,678,100 | ######### | $0 | $0 | ######### | ######### | ######### | 46.21% | 0.00% | 53.79% |
| Avista Corporation | AVA | $656,000 | $771,000 | $8,000 | ($107,000) | $354,000 | $107,000 | $2,787,000 | $2,902,000 | $2,183,000 | $2,725,000 | -$542,000 | $2,360,000 | $0 | $0 | $2,591,000 | $2,892,548 | $5,252,548 | 44.93% | 0.00% | 55.07% |
| CMS Energy Corporation | CMS | $2,790,000 | $3,521,000 | $1,198,000 | $467,000 | $65,000 | $0 | ######### | ######### | $14,876,000 | $16,386,000 | -$1,510,000 | ######### | $224,000 | $224,000 | $8,006,000 | ######### | ######### | 42.56% | 0.64% | 56.80% |
| Consolidated Edison, Inc. | ED | $6,664,000 | $6,433,000 | $119,000 | $350,000 | $2,670,000 | $0 | ######### | ######### | $21,997,000 | $24,651,000 | -$2,654,000 | ######### | $0 | $0 | ######### | ######### | ######### | 42.04% | 0.00% | 57.96% |
| Dominion Resources, Inc. | D | $6,613,000 | $9,289,000 | $1,783,000 | ($893,000) | $2,500,000 | $893,000 | ######### | ######### | $32,167,000 | $34,533,000 | -$2,366,000 | ######### | $991,000 | $991,000 | ######### | ######### | ######### | 45.50% | 1.17% | 53.33% |
| DTE Energy Company | DTE | $3,607,000 | $5,106,000 | $1,317,000 | ($182,000) | $1,067,000 | $182,000 | ######### | ######### | $20,136,000 | $21,963,000 | -$1,827,000 | ######### | $0 | $0 | ######### | ######### | ######### | 44.96% | 0.00% | 55.04% |
| Duke Energy Corporation | DUK | ######### | ######### | $4,557,000 | ($1,850,000) | $3,584,000 | $1,850,000 | ######### | ######### | $73,440,000 | $80,689,000 | -$7,249,000 | ######### | $973,000 | $973,000 | ######### | ######### | ######### | 47.45% | 0.60% | 51.94% |
| Edison International | EIX | $7,155,000 | $8,439,000 | $2,173,000 | $889,000 | $998,000 | $0 | ######### | ######### | $33,160,000 | $35,583,000 | -$2,423,000 | ######### | $1,645,000 | $1,645,000 | ######### | ######### | ######### | 51.35% | 2.46% | 46.19% |
| Entergy Corporation | ETR | $4,396,237 | $6,111,037 | $1,462,250 | ($252,550) | $927,291 | $252,550 | ######### | ######### | $25,181,802 | $27,991,595 | -$2,809,793 | ######### | $0 | $0 | ######### | ######### | ######### | 44.29% | 0.00% | 55.71% |
| Eversource Energy | ES | $5,076,073 | $6,720,957 | $1,062,360 | ($582,524) | $2,042,793 | $582,524 | ######### | ######### | $24,791,400 | $26,704,800 | -$1,913,400 | ######### | $0 | $0 | ######### | ######### | ######### | 55.19% | 0.00% | 44.81% |
| Evergy, Inc. | EVRG | $1,839,300 | $3,662,400 | $679,600 | ($1,143,500) | $1,608,600 | $1,143,500 | ######### | ######### | $11,535,000 | $12,460,900 | -$925,900 | ######### | $0 | $0 | $9,955,000 | ######### | ######### | 47.47% | 0.00% | 52.53% |
| Exelon Corporation | EXC | $8,384,000 | $9,611,000 | $1,492,000 | $265,000 | $1,859,000 | $0 | ######### | ######### | $39,057,000 | $44,400,000 | -$5,343,000 | ######### | $0 | $0 | ######### | ######### | ######### | 51.35% | 0.00% | 48.65% |
| FirstEnergy Corporation | FE | $2,776,000 | $4,997,000 | $1,028,000 | ($1,193,000) | $550,000 | $550,000 | ######### | ######### | $22,128,000 | $23,594,000 | -$1,466,000 | ######### | $0 | $0 | ######### | ######### | ######### | 49.93% | 0.00% | 50.07% |
| IDACORP, Inc. | IDA | $988,455 | $700,801 | $19,885 | $307,539 | $0 | $0 | $3,053,777 | $3,073,662 | $2,807,803 | $3,073,662 | -$265,859 | $2,807,803 | $0 | $0 | $3,330,954 | $5,844,764 | $8,652,567 | 32.45% | 0.00% | 67.55% |
| MGE Energy, Inc. | MGEE | $227,265 | $125,563 | $6,647 | $108,349 | $0 | $0 | $789,944 | $796,591 | $698,765 | $773,400 | -$74,635 | $721,956 | $0 | $0 | $1,230,138 | $3,442,974 | $4,164,930 | 17.33% | 0.00% | 82.67% |
| NextEra Energy, Inc. | NEE | ######### | ######### | $8,061,000 | ($5,343,000) | $1,887,000 | $1,887,000 | ######### | ######### | $76,428,000 | $80,446,000 | -$4,018,000 | ######### | $0 | $0 | ######### | ######### | ######### | 34.91% | 0.00% | 65.09% |
| NorthWestern Corporation | NWE | $418,186 | $802,200 | $303,546 | ($80,468) | $100,000 | $80,468 | $2,697,208 | $3,081,222 | $2,645,779 | $2,995,293 | -$349,514 | $2,731,708 | $0 | $0 | $2,857,700 | $3,249,654 | $5,981,362 | 45.67% | 0.00% | 54.33% |
| OGE Energy Corporation | OGE | $895,100 | $1,229,800 | $37,300 | ($297,400) | $469,300 | $297,400 | $5,048,700 | $5,383,400 | $4,735,000 | $5,053,300 | -$318,300 | $5,065,100 | $0 | $0 | $4,640,900 | $8,299,147 | ######### | 37.90% | 0.00% | 62.10% |
| Otter Tail Corporation | OTTR | $630,041 | $309,790 | $4,776 | $325,027 | $69,615 | $0 | $967,301 | $972,077 | $806,826 | $943,734 | -$136,908 | $835,169 | $0 | $0 | $1,668,499 | $3,127,059 | $3,962,228 | 21.08% | 0.00% | 78.92% |
| Pinnacle West Capital Corporation | PNW | $1,689,404 | $2,843,797 | $900,367 | ($254,026) | $568,450 | $254,026 | $9,579,525 | ######### | $7,405,000 | $8,405,000 | -$1,000,000 | $9,733,918 | $0 | $0 | $6,754,311 | $9,658,800 | ######### | 50.19% | 0.00% | 49.81% |
| TXNM Energy | TXNM | $498,836 | $1,775,098 | $635,022 | ($641,240) | $609,300 | $609,300 | $4,583,611 | $5,827,933 | $4,706,076 | $4,923,368 | -$217,292 | $5,610,641 | $0 | $0 | $2,536,385 | $4,371,111 | $9,981,752 | 56.21% | 0.00% | 43.79% |
| Portland General Electric Company | POR | $1,025,000 | $1,119,000 | $223,000 | $129,000 | $0 | $0 | $4,948,000 | $5,171,000 | $3,963,000 | $4,524,000 | -$561,000 | $4,610,000 | $0 | $0 | $3,794,000 | $4,589,427 | $9,199,427 | 50.11% | 0.00% | 49.89% |
| PPL Corporation | PPL | $2,880,000 | $3,333,000 | $575,000 | $122,000 | $303,000 | $0 | ######### | ######### | $15,562,000 | $16,503,000 | -$941,000 | ######### | $0 | $0 | ######### | ######### | ######### | 39.58% | 0.00% | 60.42% |
| Public Service Enterprise Group Inc. | PEG | $4,235,000 | $6,505,000 | $2,178,000 | ($92,000) | $1,593,000 | $92,000 | ######### | ######### | $19,341,000 | $21,114,000 | -$1,773,000 | ######### | $0 | $0 | ######### | ######### | ######### | 31.67% | 0.00% | 68.33% |
| Southern Company | SO | ######### | ######### | $4,918,000 | ($381,000) | $1,338,000 | $381,000 | ######### | ######### | $57,700,000 | $63,200,000 | -$5,500,000 | ######### | $0 | $0 | ######### | ######### | ######### | 39.64% | 0.00% | 60.36% |
| Xcel Energy Inc. | XEL | $4,325,000 | $6,459,000 | $1,332,000 | ($802,000) | $695,000 | $695,000 | ######### | ######### | $25,115,000 | $28,419,000 | -$3,304,000 | ######### | $0 | $0 | ######### | ######### | ######### | 40.80% | 0.00% | 59.20% |
| MEDIAN | | | | | | | | | | | | | | | | | | | 44.61% | 0.00% | 55.39% |

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**

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

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| 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.

Statement No. 3-RJ

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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|---|---|---|
| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company (electric) | : | |

**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. Grandinali and to update the status of Pike's personnel plans.

**Q: Why are you adopting Mr. Verbraak's testimony?**

A: Mr. Grandinali testified on behalf of Pike during the interim between when Mr. Verbraak the prior General Manager left the Company and I joined 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 10-11 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**

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| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company – Electric | : | |

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**TESTIMONY VERIFICATION OF PAUL M. NORMAND**
**ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY**

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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 the accompanying Exhibit Nos. E-6, E-7 and E-8; and
- PCLP Statement No. 1-R – Rebuttal Testimony of Paul M. Normand.

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
Management Consultant and President
Management Applications Consulting, Inc.

**BEFORE THE**
**PENNSYLVANIA PUBLIC UTILITY COMMISSION**

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| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
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| Pike County Light & Power Company – Electric | : | |

## 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, I 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, including Exhibit Nos. E-1, E-2, E-3, E-4, E-5 and Verification of Customer Notice, Notice of Proposed Electric Rate Changes and Public Notice Electric Rates; and
- PCLP Statement No. 2-R – Rebuttal Testimony of Accounting Panel (Charles Lenns and Matthew Lenns), including Pike AP-E Update (Schedule Nos. 1-12) and Exhibit AP-1R.

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**

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| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
| | : | |
| Pike County Light & Power Company – Electric | : | |
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**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**

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| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
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| Pike County Light & Power Company – Electric | : | |
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**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, including Exhibit Nos. CMW-1R, CMW-2R, CMW-3R, CMW-4R, CMW-5R, CMW-6R, CMW-7R and CMW-8R.

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**

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| Pennsylvania Public Utility Commission | : | |
| | : | |
| v. | : | Docket No. R-2024-3052359 |
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| Pike County Light & Power Company – Electric | : | |

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**TESTIMONY VERIFICATION OF NANCY KARLOVICH**
**ON BEHALF OF PIKE COUNTY LIGHT AND POWER COMPANY**

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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 Steven Grandinali (adopted by 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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Ryan Morden, Esquire
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*/s/ Whitney E. Snyder*
Whitney E. Snyder
Erich W. Struble

DATED: June 6, 2025