COMMONWEALTH OF PENNSYLVANIA

DARRYL A. LAWRENCE
Acting Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

@pa_oca
/pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

June 3, 2025

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

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

Dear Secretary Homsher:

Consistent with 52 Pa. Code Section 5.412a of the Commission's regulations, which requires the electronic submission of pre-served testimony, please note that the following pre-served testimony on behalf of the Office of Consumer Advocate ("OCA") was submitted via eFiling on June 3, 2025, in the above-referenced proceeding.

DIRECT TESTIMONY

OCA Statement 1:	Direct Testimony of Jennifer L. Rogers consisting of 24 pages of testimony, Appendix A, and Schedules JLR-1 through JLR-18 along with a signed verification of Jennifer L. Rogers.
OCA Statement 2:	Direct Testimony of Maureen L. Reno consisting of 56 pages of testimony, Appendix A, and Exhibits MLR-1 through MLR-6 along with a signed verification of Maureen L. Reno.
OCA Statement 3:	Direct Testimony of Karl R. Pavlovic consisting of 26 pages of testimony and Exhibits KRP-1 through KRP-3 along with a signed verification of Karl R. Pavlovic.

REBUTTAL TESTIMONY

OCA Statement 3R: Rebuttal Testimony of Karl R. Pavlovic consisting of 9 pages of testimony along with a signed verification of Karl R. Pavlovic.

SURREBUTTAL TESTIMONY

OCA Statement 3SR: Surrebuttal Testimony of Karl R. Pavlovic consisting of 13 pages of testimony along with a signed verification of Karl R. Pavlovic.

Copies of this letter are being served on parties of record per the attached Certificate of Service.

Respectfully submitted,

/s/ Jacob D. Guthrie

Jacob D. Guthrie, Esq.
Assistant Consumer Advocate
PA Attorney I.D. # 334367
Email: JGuthrie@paoca.org

Enclosures

cc: The Honorable Alphonso Arnold III (**email only:** alphonarno@pa.gov)
The Honorable Marta Guhl (**email only:** mguhl@pa.gov)
Certificate of Service

OCA Statement 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission		
	)	
v.	)	
	)	**Docket No. R-2024-3052359**
Pike County Light & Power Company-Electric	)	
	)	

DIRECT TESTIMONY

OF

JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 3, 2025

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jennifer L. Rogers. My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland, 21044. I am a Principal and Vice President at Exeter Associates, Inc. ("Exeter"). Exeter is a consulting firm specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Arts degree in Economics from Northeastern University. I also have a Bachelor of Arts degree in Economics with a minor in Environmental Studies from St. Mary's College of Maryland.

I attended the 42nd Eastern National Association of Regulatory Utility Commissioners ("NARUC") Utility Rate School. I have also completed the Institute of Public Utilities Accounting and Ratemaking Course and the Advanced Course: Regulatory Accounting and Auditing, as well as EUCI's Electric Cost-of-Service Course.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed with Exeter since 2009, initially as a Research Assistant before being promoted to Economist, then Senior Economist, and then Lead Economist. I am now a Principal and Vice President for the firm. At Exeter, I review utility rate filings and provide analysis of revenue requirement issues. I also evaluate and forecast power supply requirements, costs, and renewable energy needs; provide bill and rate analysis; and review energy use, scheduling, and scheduling deviation data for clients. In addition, I conduct utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of supply contracts, energy use, and a review of billing practices.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony before the Pennsylvania Public Utility Commission; the Philadelphia Water, Sewer, and Storm Water Rate Board; the Maryland Public Service Commission; the Public Utility Commission of Texas; the Maine Public Utilities Commission; and the State Corporation Commission of the State of Kansas. My resume is attached as Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter has been retained by the OCA to assist in the evaluation of the application of the Pike County Light & Power Company- Electric Division ("PCLP" or "Company") to increase base rates for electric service. My direct testimony presents my findings with respect to PCLP's revenue requirements and its proposed rate increases. I calculate PCLP's rate base, pro forma operating income under present rates, and overall revenue deficiency based upon my recommended adjustments. Additionally, Maureen Reno will present the OCA's recommendations regarding rate of return (OCA Statement 2). In her direct testimony, Ms. Reno recommends an overall rate of return on rate base of 7.85%.

Further, Karl R. Pavlovic will present the OCA's recommendations regarding cost of service, revenue allocation, and rate design. (OCA Statement 3). Based on my revenue requirement recommendation, Mr. Pavlovic presents an alternative revenue allocation and scale back proposal.

II. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RATE RELIEF REQUESTED BY PCLP IN ITS FILING.

A. On January 14, 2025, PCLP filed an application with the Pennsylvania Public Utility Commission ("Commission") to increase its base rates for electric service. PCLP is requesting an overall rate increase of $1,874,600. The Company's proposed rate increase is based upon the future test year ("FTY") ending September 30, 2025. The Company's requested rate increase reflects an overall rate of return ("ROR") of 8.37%. I would note that, while the Company requested to roll in its current distribution system improvement charge balance of $269,300 into rates, for an overall requested increase of $2,143,900, I do not address this request in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. As shown on Schedule JLR-1, I have determined that PCLP's proposed revenue increase should be reduced to reflect an increase of no more than $1,334,200 for the FTY. My recommendation includes a correction to the Company's calculation of interest synchronization, discussed in the 'Interest Synchronization' section of my Direct Testimony, that results in an upward adjustment of over $400,000 to income taxes, which nets out the impact of many of the other adjustments I propose below.

My recommendation is $540,400 less than the Company's requested increase of $1,874,600. My recommendation reflects an overall rate of return on rate base of 7.85%, which is per the recommendation detailed in the Direct Testimony of Maureen Reno.

Q. WHAT PERIOD HAVE YOU USED IN MAKING YOUR DETERMINATION OF PCLP'S REVENUE REQUIREMENT?

A. I have determined my revenue requirement recommendations based on the future test year ending September 30, 2025. This is the same period used by the Company to develop its revenue requirement.

Q. IN CONNECTION WITH THIS CASE, WHAT DOCUMENTS HAVE YOU EXAMINED AND REVIEWED IN MAKING YOUR RECOMMENDATIONS?

A. I have reviewed PCLP's rate filing, testimony, and exhibits. I also reviewed the Company's responses to data requests propounded by the OCA, the Office of Small Business Advocate ("OSBA"), and the Bureau of Investigation and Enforcement ("I&E").

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules JLR-1 through JLR-18. Schedule JLR-1 provides a summary of the calculation of the increase in revenues after reflecting the adjustments proposed by the OCA. Schedule JLR-2 provides my recommended rate base. Schedule JLR-3 presents the summary of the cost of service (revenues and operating expenses) adjustments. My adjustments to PCLP's claimed revenues and operating expenses are presented on Schedules JLR-4 through JLR-18.

Q. PLEASE EXPLAIN HOW THE REMAINING SECTIONS OF YOUR TESTIMONY ARE ORGANIZED.

A. The discussion of my findings and recommendations is presented in the following section, Section III. In that section, I address the revenue requirement issues (rate base and operating income) that I identified in this proceeding. Where I recommend an adjustment to a particular component of the rate base, revenues, or expenses, I document and explain the reason for the adjustment and note the related schedule in which the detailed calculations can be found. An outline of the topics within the section is set forth in the Table of Contents of my testimony.

III. ADJUSTMENTS

Summary of OCA Adjustments	
Rate Base	
Plant in Service	($2,302,500)
Accumulated Depreciation	$526,250
ADIT	$23,700
Deferred debit in Rate Base: Rate Case Expense	($192,440)
Deferred Debit in Rate Base: Storm Riley	($109,660)
Cash Working Capital	($15,848)
Total Adjustment to Rate Base:	**($2,070,498)**
Expenses and Interest Synchronization	
Depreciation Expense	($133,500)
M&T Credit Card Charges	($170,000)
Informational Advertising	($4,708)
Auditing	($47,888)
Intercompany A&O: Inflation Adjustment	($7,800)
Minor Storms Expense	($265,816)
Annual Dinner Expense	($1,360)
Interest Synchronization	$455,692
Total Adjustment to Expenses:	**($175,380)**

A. **<u>Plant In Service</u>**

Q. BRIEFLY DESCRIBE THE COMPANY'S PROPOSAL RELATED TO PLANT IN SERVICE.

A. The Company is proposing to include $45 million of utility plant in rate base, including electric plant in service, common plant in service which is allocated between electric and gas divisions, and general plant allocated from Corning Gas.[1] While general plant allocated from Corning Gas does not extend beyond the FTY, the Company has proposed extending the electric and common plant in service values through a post future test year period October 2025 through March 31, 2026.[2]

Q. DO YOU AGREE WITH THE COMPANY'S INCLUSION OF POST FUTURE TEST YEAR PLANT ADDITIONS AND RETIREMENTS THROUGH MARCH 31, 2026?

A. No, I do not. The Company is claiming a future test year ending September 30, 2025. Therefore, the inclusion of net plant additions through March 30, 2026, is inappropriate as those go beyond the future test year and these plants will not be used and useful by the end of the period the Company has selected to establish the rates. This also creates a mismatch between plant in service in the cost of service with the revenues and operating expenses, which were forecast consistent with the FTY. This is in violation of the accounting principal of matching, which dictates that financial statements should be presented on a consistent basis. Revenues, operating expenses, assets, liabilities and owners' equity should all be recognized in the period in which they are incurred and/or expenditures are made. Therefore, revenues should be recorded in the accounting

[1] Company Exhibit E-3, Summary page 1.
[2] Company Exhibit E-3, Schedule 1.

period in which they are earned, and expenses should be recorded during the period that benefits from the expense. Similarly, assets, liabilities and shareholder equity are to be recorded during the period in which the expenditures are made or funds are received. For a specific accounting period, the forementioned components should all be reported for the same period as a matter of consistency.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PLANT IN SERVICE.

A. For the reasons explained above, I recommend disallowing the inclusion of the post future test year plant additions and retirements. This adjustment removes $2,470,000 in post FTY plant additions and ($167,500) of post FTY plant retirements, for a net reduction in rate base totaling $2,302,500, as shown on Schedule JLR-5.

B. <u>Accumulated Depreciation</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ACCUMULATED DEPRECIATION.

A. As explained in the 'Plant In Service' section of my direct testimony, I am recommending the Commission disallow the inclusion of post FTY plant additions, which necessitates an additional adjustment to remove accumulated depreciation associated with the post FTY period from the cost of service. The Company has included in rate base $447,200 of accumulated depreciation for electric plant and $79,050 of accumulated depreciation for common plant associated with the post FTY period additions and retirements October 1, 2025 through March 31, 2026.[3] Consistent with my recommendation to disallow post FTY plant additions, I therefore have made an adjustment to remove the post FTY accumulated depreciation. This adjustment increases rate base by $526,250, as shown on Schedule JLR-6.

[3] Company Exhibit E-3, Schedule 2.

C. Accumulated Deferred Income Taxes

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

A. The Company has proposed an ADIT balance of $1,773,000. As explained in the 'Plant In Service' section of my direct testimony, I am recommending the Commission disallow the inclusion of post FTY plant additions. The Company has included $23,700 of accumulated deferred income taxes associated with the post FTY period October 1, 2025 through March 31, 2026.[4] Consistent with my recommendation to disallow post FTY plant additions, I therefore have made an adjustment to remove the post FTY accumulated deferred income taxes. This adjustment increases rate base by $23,700, as shown on Schedule JLR-7.

D. Deferred Debit: Rate Case Expense

Q. PLEASE DESCRIBE THE COMPANYS PROPOSAL RELATED TO THE DEFERRED DEBIT FOR RATE CASE EXPENSE.

A. The Company has included $192,440 in rate base deferred debit associated with Rate Case Acct 186171, rounded value after tax.[5]

Q. DO YOU AGREE WITH THE INCLUSION OF RATE CASE EXPENSES IN RATE BASE?

A. No, I do not. It is my understanding that no return is allowed to be earned on expenses, only on capital investments. Expenses are to be recovered without profit. Including these accumulated expenses in the rate base would allow the Company to inappropriately earn a return on these expenses, which is not permitted.

[4] Company Exhibit E-3, Schedule 9.
[5] Company Exhibit E-3, Schedule 6.

Further, it appears the Company has included this in rate base in error. In response to I&E-RE-15-D, when asked why it is appropriate to include this deferred value in rate base, the Company states that they do not seek to defer expenses incurred for prior rate cases for recovery in this rate case. The Company also states that while they have listed rate case expenses as an amortization, they actually are seeking to normalize rate case expense. Normalized expenses should not be included in rate base.

I recommend normalizing rather than amortizing this expense, and disallowing inclusion of rate case expenses in rate base. This reduces rate base by $192,440, as shown in Schedule JLR-8.

E. Deferred Debit: Storm Riley

Q. PLEASE DESCRIBE THE COMPANYS PROPOSAL RELATED TO THE DEFERRED DEBIT FOR STORM RILEY.

A. The Company has included $109,660 in rate base deferred debit associated with Hurricane Riley, rounded value after tax.[6]

Q. DO YOU AGREE WITH THE INCLUSION OF DEFERRED DEBIT FOR STORM RILEY IN RATE BASE?

A. No, I do not. Deferred charges are generally expenses incurred in prior periods that are recorded in a temporary asset account to be written off as expenses in the future. Inclusion of deferred costs in rate base should be authorized by the Commission. The Company has not received Commission approval to include these deferred charges in rate base, as per Company response to I&E-RE-24-D, part C. When asked to explain the basis for including the deferred debits in rate base for Hurricane Riley, the Company

[6] Company Exhibit E-3, Schedule 6.

provided no basis for its inclusion.[7] I therefore recommend disallowing inclusion of these costs in rate base. This reduces rate base by $109,660, as shown in Schedule JLR-9.

F. <u>Allowance for Cash Working Capital</u>

Q. HOW DO YOU DEFINE CASH WORKING CAPITAL?

A. For ratemaking purposes, cash working capital is the investment that a utility needs to have on hand to fund its day-to-day operations. Positive cash working capital represents funds provided by investors that should be included in rate base so that the utility earns a return on it. Negative cash working capital represents funds supplied by ratepayers that should be recognized as a rate base offset to reflect funds advanced for operations by ratepayers.

Q. HOW DID THE COMPANY REFLECT CASH WORKING CAPITAL IN ITS FILING?

A. The Company's cash working capital allowance has been determined based upon the results of a lead/lag study. A lead/lag study is an in-depth analysis that measures the difference between the lapse of time when a company receives revenue for the provision of service and the lapse of time when a company pays for the costs of providing service. This difference is expressed as a number of days and is used to calculate the level of investor-supplied funds advanced for operations, or the funds advanced by customers for operations.

[7] Company response to I&E-RE-24-D, part B.

Q. WHAT CHANGES HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. Since O&M expenses serve as the basis upon which the cash working capital is calculated, I have incorporated the adjustments to O&M expenses that I am recommending below. I have therefore made an adjustment to cash working capital to reduce rate base by $15,848, as shown on Schedule JLR-4.

G. <u>Depreciation Expense</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSES.

A. As explained in the 'Plant In Service' section of my direct testimony, I am recommending the Commission disallow the inclusion of post FTY plant additions, which necessitates an additional adjustment to the depreciation expenses. Consistent with my recommendation to disallow post FTY plant additions and retirements, I therefore have made an adjustment to remove the post FTY additions and retirements from the Company's calculation of depreciation expenses. This reduces depreciation expenses by $94,000.

I have also made a correction to the Company's calculation. On the "Electric Depreciable Plant at September 30, 2025" line item, the company has subtracted retirements.[8] The retirements were recorded as negative values, and subtracting these negatives has added the retirements into the depreciable plant value rather than removing them. I have changed the calculation to add the negative values rather than subtract. Having already removed the Post FTY additions and depreciations, this correction then further reduces the depreciation expenses by $39,500. In total, my

[8] Company Exhibit E-4, Schedule 12 page 1.

adjustment decreases depreciation expenses by $133,500, as shown on Schedule JLR-10.

H. M&T Credit Card Charges

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED M&T CREDIT CARD CHARGES INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. The Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged to O&M expenses for the twelve months ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[9]

These Intercompany A&O Charges are comprised of numerous expense items, one of which is 'M&T Credit Card Charges,' which totaled $202,824 in the year ending September 30, 2024.[10] These are total values, of which 85% is allocated to the electric division.[11]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED M&T CREDIT CARD CHARGES EXPENSE?

A. No, I do not. The Company is proposing to base the value on the actual amounts charged for the twelve months ended September 30, 2024, before applying a general one percent inflation factor. I address the one percent inflation factor in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony. With respect to the twelve months ended September 30, 2024, the value increased from $3,006 in year ended September 30, 2023, to $202,824 in year ended

[9] Company Exhibit E-4, Schedule 10.
[10] Company response to I&E-RE-16-D, "Q16 – Intercompany allocations 2022-2024'.
[11] Company response to OCA 11-3.

September 30, 2024. In response to I&E-RE-42, the Company explained that "The M&T credit card charges include a one-time intercompany reclass between Pike and Corning Natural Gas of $200,000, and is mislabeled as a bank fee. This was a one-time intercompany transfer for a balance that was booked in the wrong GL account, and is not expected to occur again." The Company went on to explain that this value represents a loan, which was recorded as a credit card expense in error.[12] This represents a one-time loan, not an expense, and therefore should not be included in the cost of service.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPOSED M&T CREDIT CARD CHARGES INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. For the reasons explained above, I recommend disallowing the $200,000 value associated with the one-time intercompany reclass. To calculate the adjustment, I first applied an 85 percent allocation factor to the original values, reflecting the portion allocated to the electric division. I then remove the portion of the total M&T Credit Charges associated with the loan. This adjustment reduces O&M expenses by $170,000, as shown on Schedule JLR-11. I address the one percent inflation factor, which the Company proposes to apply to all Intercompany Administrative & Operating Charges expenses, in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony.

[12] Company response to OCA 13-1.

I. Informational Advertising

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INFORMATIONAL ADVERTISING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. As previously discussed, the Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged for the year ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[13]

These Intercompany Administrative & Operating Charges are comprised of numerous expense items, one of which is 'Informational Advertising' totaling $8,618 in the year ending September 30, 2024.[14] Note that these are total values, of which 85% is allocated to the electric division.[15]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED INFORMATIONAL ADVERTISING EXPENSE?

A. No, I do not. The Company is proposing to base the value on the actual amounts charged for the twelve months ended September 30, 2024, before applying a general one percent inflation factor. I address the one percent inflation factor in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony. With respect to the twelve months ended September 30, 2024, this 2024 basis for the Informational Advertising charges is abnormally high, as shown in the chart below.

[13] Company Exhibit E-4, Schedule 10.
[14] Company response to I&E-RE-16-D, "Q16 – Intercompany allocations 2022-2024'.
[15] Company response to OCA 11-3.

	12 mos. Ending September 2022	12 mos. Ending September 2023	12 mos. Ending September 2024
Informational Advertising[16]	$449	$171	$8,618

Informational advertising expenses are a variable cost item, increasing and decreasing depending on the year. In response to discovery, the Company did not provide any indication that costs would remain at an elevated level going forward.[17] Basing rates on these abnormally high 2024 expenses could result in an overcollection from customers.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPOSED INFORMATIONAL ADVERTISING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. I am recommending normalizing the annual expense level allocated to the electric division (85% of the total values) using the average of the most recent three years rather than the value for the year ended September 30, 2024. This adjustment is presented on Schedule JLR-12, and results in a decrease to O&M expenses of $4,708. I address the one percent inflation factor the Company proposes to apply to all Intercompany Administrative & Operating Charges expenses in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony.

[16] Company response to I&E-RE-16-D, "Q16 – Intercompany allocations 2022-2024'.
[17] Company response to I&E-RE-42.

J. <u>Auditing Expenses</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED AUDITING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. As previously discussed, the Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged for the year ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[18]

These Intercompany Administrative & Operating Charges are comprised of numerous expense items, one of which is 'Auditing' totaling $87,342 in the year ending September 30, 2024.[19] Note that these are total values, of which 85% is allocated to the electric division.[20]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED AUDITING EXPENSE?

A. No, I do not. The Company is proposing to base the value on the actual amounts charged for the twelve months ended September 30, 2024, before applying a general one percent inflation factor. I address the one percent inflation factor in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony. With respect to the twelve months ended September 30, 2024, this 2024 basis for the Auditing charges is abnormally high, as shown in the chart below.

[18] Company Exhibit E-4, Schedule 10.
[19] Company response to I&E-RE-16-D, "Q16 – Intercompany allocations 2022-2024'.
[20] Company response to OCA 11-3.

	12 mos. Ending September 2022	12 mos. Ending September 2023	12 mos. Ending September 2024
Auditing[21]	$4,365	$1,302	$87,342

PCLP transitioned Companies for the 2023 audit and were billed for costs of the audit transition, resulting in unusually high auditing expenses in the twelve months ending September 2024.[22] Not only were additional costs incurred for the transition, but it is also reasonable to assume that this cost will be higher in the first year of a switch to a new company than it will be in subsequent years due to the principle of economy of repetition, wherein processes for recurring tasks are developed and refined as they are repeated, which results in efficiency gains and lower costs. Using this year as the basis for future expenses could result in an overcollection from customers given this out of the ordinary activity that occurred.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO PROPOSED AUDITING COSTS INCLUDED IN THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. I am recommending normalizing the annual expense level allocated to the electric division (85% of the total values) using the average of the most recent three years rather than the value for the year ended September 30, 2024. This adjustment is presented on Schedule JLR-13, and results in a decrease to O&M expenses of $47,888. I address the one percent inflation factor the Company proposes to apply to all Intercompany Administrative & Operating Charges expenses in the 'Intercompany Administrative & Operating Charges: Inflation' section of my direct testimony.

[21] Company response to I&E-RE-16-D, "Q16 – Intercompany allocations 2022-2024'.
[22] Company response to I&E-RE-42.

K. <u>Intercompany Administrative & Operating Charges: Inflation</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. The Company has based its Intercompany Administrative & Operating Charges expense on the actual amount charged for the year ended September 30, 2024, which totals of $780,177. They then applied a one percent inflation factor, increasing the expense by $7,800.[23]

Q. DO YOU AGREE WITH THE COMPANY'S USE OF AN INFLATION ADJUSTMENT TO THESE EXPENSES?

A. No, I do not. The Company's application of a one percent inflation escalation is problematic for several reasons. First, in response to discovery, the Company was not able to provide any backup data or documentation to show the basis of how they projected a one percent inflation rate, merely stating this was an estimate.[24] Second, the Intercompany Administrative & Operating Charges reflect a wide variety of expense items, such as landscaping, credit card charges, petty cash, maintenance and repair, and more.[25] Some of the costs included in this category are not subject to inflationary increases, and an inflationary adjustment is, therefore, inappropriate. Moreover, a blanket escalation adjustment does not reflect actual expectations for the expense items in the FTY. It is apparent in the historical data that many of these costs are variable, with some increasing and others decreasing year over year to varying degrees. This blanket escalator does not capture actual expected expenses. Finally, the $780,177

---

[23] Company Exhibit E-4,Schedule 10.
[24] Company response to OCA 7-23.
[25] Company response to I&E-RE-16-D, "Q16 – Intercompany allocations 2022-2024'.

amount to which the Company has applied the one percent escalation is a total value, which is allocated between electric and gas customers, with 85% applicable to the electric cost of service. In applying the escalation to the total amount of Intercompany Administrative & Operating Charges, not solely the electric service portion, the Company has included an adjustment that includes increases allocated to the gas division. This is inappropriate to apply to electric customers and double counts increases applied in the gas division's rate case.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE INTERCOMPANY ADMINISTRATIVE & OPERATING CHARGES EXPENSE.

A. For the reasons detailed above, I am recommending the Commission disallow the inflation escalation adjustment the Company has applied to the Intercompany Administrative & Operating Charges. This adjustment reduces O&M expenses by $7,800, as shown on Schedule JLR-14

L. <u>Minor Storms Expense</u>

Q. PLEASE ADDRESS THE COMPANY'S PROPOSAL RELATED TO MINOR STORMS EXPENSE.

A. The company's filed cost of service proposes to amortize Minor Storms expenses of $150,000 per the calculation on Exhibit E-4, Schedule 7.[26] In response to discovery, however, the Company stated, "The $150,000 in estimated future small storm costs is not a historical test year cost sought to be amortized, it is a normalized estimate for future test period storm costs based on past small storm costs. The Company intended

[26] Company Exhibit E-4, Schedule 7.

to claim this $150,000 as an expense and will address this issue in its rebuttal testimony."[27]

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION METHOD TO INCORPORATE MINOR STORM EXPENSES INTO THE COST OF SERVICE?

A. No, I do not. First, the Company explained in discovery that including this item as an amortization calculation was in error, and I note the model has included the value erroneously in the 'amortization' and 'Balance' columns of Exhibit E-4, Schedule 7.[28] I agree with the Company that this value should be classified as normalized rather than amortized. Second, it does not appear that the Company has accurately reflected this as an adjustment from minor storm expenses already included in the historic year ended September 30, 2024 to reach the FTY value. The Company's proposed minor storm expenses for the FTY are not adjusted from any existing amount in the historic year, but rather appear to have been simply added in.[29] This would mean the Company is recovering the full value of minor storm expenses included in the historic year expenses as well as the value they have proposed to include going forward. When I asked directly for the Company to state the amount of minor storm expenses included in the electric cost of service for the historic year, adjustments, and future test year, the Company did not provide the information in their response.[30] I therefore must assume that the amount of minor storm expenses stated to have been incurred in year ended September 30, 2024, which total $146,866 per the Company's response to OCA 11-8.a, reflect the amount included in the cost of service historic year ended September 30, 2024. The

[27] Company response to OCA 11-8.
[28] Company response to OCA 11-8; and Company Exhibit E-4, Schedule 7.
[29] Company Exhibit E-4, Schedule 7.
[30] Company response to OCA 11-8.c.

Company should be adjusting from the historic expense amount to reach the proposed FTY value.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED MINOR STORMS EXPENSE VALUE?

A. As stated previously, I agree with the Company that this expense should be classified as normalized rather than amortized, however I disagree with the $150,000 projection. The Company stated in discovery response that they intend to claim $150,000 as an expense, which was estimated based on 2024 storm work orders.[31] When I examined historical minor storm expenses, however, I noted that 2024 was an extremely high year as compared to other years.

	12 mos. Ending September 2022	12 mos. Ending September 2023	12 mos. Ending September 2024
Minor Storm Expenses[32]	$0	$58,819	$146,866

The twelve months ended September 2024 is abnormally high, and I note the Company is proposing to include an even higher value of $150,000. Using this estimate of minor storm expenses could result in overcollection from customers. I therefore believe it is necessary to normalize the value by taking the average of the three historical years of expenses.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO MINOR STORMS EXPENSE.

A. For the reasons explained above, I first remove the Minor Storms values from the Company's existing calculation of the amortization of storm deferral balances, which reduces O&M expenses by $187,512. I then calculate an expense adjustment for Minor

[31] Company response to OCA 11-8.
[32] Company response to OCA 11-8, "Pike Storm Work Orders" Excel attachment.

Storms by averaging the most recent three years of expenses to reach a normalized value of $68,562. I adjust this from what I understand to be the historic year expense value of $146,866 (as explained above) such that the normalized value is what will be included in the FTY and is not additive to existing minor storm expenses already included in the historic year. This further reduces O&M expenses by $78,304. The total impact of the adjustment is a reduction to O&M expenses of $265,816, as shown in Schedule JLR-15. If the Company is able to supply additional information in rebuttal regarding the minor storms historic year expenses included in the cost of service, I may adjust this recommendation.

M. Annual Dinner Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATED TO THE GREATER PIKE COMMUNITY FOUNDATION ANNUAL DINNER.

A. The Company has included $1,600 related to the Greater Pike Community Foundation for their annual dinner in the cost of service, of which 85% is allocated to electric division. In response to discovery, the Company explained that the benefit associated with this expense is related to supporting the community.[33] This is related to image building and public relations for the Company, which benefits shareholders, rather than provide service to ratepayers. Ratepayers should therefore not be responsible for this expense, and I recommend disallowing expenses related to the Greater Pike Community Foundation for their annual dinner from inclusion in the cost of service. This adjustment reduces O&M expenses by $1,360, as shown in Schedule JLR-15.

[33] Company response to OCA 11-7.

N. Interest Synchronization

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION OF INTEREST SYNCHRONIZATION?

A. No, I do not. To determine the tax-deductible interest for ratemaking, the recommended rate base is multiplied by the weighted cost of debt included in the capital structure. This procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers.

In the Company's proposed cost of service, they have applied the unweighted cost of debt from a prior DSIC filing to rate base for interest synchronization, which is incorrect. The weighted cost of debt is the portion of debt that supports rate base, and therefore it is this value which must be used in the calculation to correctly determine the interest expense. The Company has multiplied the unweighted long-term cost of debt from their Pike Electric DSIC filing for Q3 2024, 7.21%, by their proposed rate base in calculating their interest synchronization.[34] In the proposed capital structure for this case, however, the Company has proposed a weighted cost of debt of 3.44%.[35] Applying the 3.44% weighted cost of debt included in the capital structure is the correct method to determine the interest component of the return on rate base to be recovered from ratepayers. The Company therefore undercalculated income taxes by $401,915 in the Company's proposed model.

[34] Company Exhibit E-4, Schedule 14.
[35] Company Exhibit E-2, Schedule 3.

Q. PLEASE EXPLAIN YOUR INTEREST SYNCHRONIZATION ADJUSTMENT.

A. To determine the tax-deductible interest for ratemaking, I multiplied the OCA's recommended rate base by the weighted cost of debt included in the capital structure recommended per the direct testimony of OCA Witness Reno. As previously discussed, this procedure synchronizes the interest deduction for tax purposes with the interest component of the return on rate base to be recovered from ratepayers. This adjustment increases state income taxes by $133,310 and federal income taxes by $322,382, as shown on Schedule JLR-16.

Q. DOES THIS COMPLETE YOUR DIRECT 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	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

JENNIFER L. ROGERS

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 3, 2025

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

APPENDIX A – Resume of Jennifer L. Rogers

JENNIFER L. ROGERS

Ms. Rogers is a Principal and Vice President at Exeter Associates, Inc., with over fifteen years of experience in the energy industry. At Exeter, Ms. Rogers reviews and analyzes utility rate filings, and presents testimony focusing primarily on revenue requirements determination. She also evaluates and forecasts power supply requirements, costs, and renewable energy needs; provides bill and rate analysis; and reviews energy use, scheduling, and scheduling deviation data for clients. In addition, Ms. Rogers conducts utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of supply contracts, energy use, and a review of billing practices.

Education

B.A. (Economics) – Saint Mary's College of Maryland, 2007

M.A. (Economics) – Northeastern University, Boston, MA, 2009

Previous Employment

2009-Current Exeter Associates, Inc.
Columbia, MD

- Principal and Vice President 2025-Current
- Lead Economist 2023-2024
- Senior Economist 2018-2022
- Economist 2011-2017
- Research Assistant 2009-2010

2007-2008 Economics Research and Teaching Assistant
Northeastern University
Boston, MA

Professional Experience

Ms. Rogers' work at Exeter is primarily related to analysis of revenue requirement issues in utility rate filings, analysis power supply acquisition, bill and rate analysis and forecasting, and utility service assessment. Ms. Rogers provides support to the U.S. Department of Energy's Northern California national laboratories, generating cost simulations and power procurement models to forecast future power supply requirements and costs. In addition, Ms. Rogers reviews and tracks the Laboratories' billing, energy use, scheduling, and scheduling deviation data. Ms. Rogers works with the U.S. Air Force Civil Engineer Center to complete utility service assessments to identify areas for potential utility cost savings, providing detailed analysis of energy usage, supply contracts, and a review of billing practices. Ms. Rogers also assists clients in reviewing utility rate filings, providing analysis on revenue requirement issues. Ms. Rogers' work at Exeter has also included assisting in studies of variable generation forecasting, feed-in tariffs for renewable energy generation, and transmission cost allocation methodologies.

As a Research Assistant at Northeastern University, Ms. Rogers worked in the fields of industrial organization and labor economics, while her studies focused on economic modeling and policy analysis. Ms. Rogers developed surveys to be used in a longitudinal labor economics study, tutored undergraduate economics students, and provided research on a variety of economics-related topics.

Expert Testimony

Before the Pennsylvania Public Utility Commission, Docket No. R-2024-3050208, Newtown Artesian Water Company, 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Maryland Public Utility Commission, Case No. 9744, Hagerstown Light Department, 2024, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Maryland Public Utility Commission, Case No. 9719, Easton Utilities Commission, 2024, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket Nos. R-2023-3042804 and R-2023-3042805, Community Utilities of Pennsylvania Inc., 2024, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the State Corporation Commission of the State of Kansas; Docket No. 23-EKCE-775-RTS; Evergy Kansas Central, Inc., Evergy Kansas South, Inc. and Evergy Metro, Inc.; 2023; on behalf of the United States Department of Defense and all other Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2023-3040258, Columbia Water Company, 2023, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Maine Public Utilities Commission, Docket No. 2023-00065, Maine Water Company – Biddeford & Saco Division, 2023, on behalf of the Maine Office of the Public Advocate. Testimony addressed revenue requirement issues.

Before the Philadelphia Water, Sewer, and Storm Water Rate Board, Fiscal Years 2024-2025 Rate Proceeding, Philadelphia Water Department, 2023, on behalf of the Public Advocate. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2022-3032764, Leatherstocking Gas Company, LLC., 2022, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Before the Public Utility Commission of Texas, Docket No. 53601, Oncor Electric Delivery Company LLC, 2022, on behalf of the United States Department of Defense and the Federal Executive Agencies. Testimony addressed revenue requirement issues.

Before the Maryland Public Service Commission, Case No. 9680, Columbia Gas of Maryland, Inc., 2022, on behalf of the Maryland Office of People's Counsel. Testimony addressed revenue requirement issues.

Before the Pennsylvania Public Utility Commission, Docket No. R-2015-2462723, United Water Pennsylvania, Inc., 2015, on behalf of the Pennsylvania Office of Consumer Advocate. Testimony addressed revenue requirement issues.

Publications and Consulting Reports

A Survey of Variable Generation Integration Charges, National Renewable Energy Laboratory, NREL Report No. NREL/TP-5500-57583, March 2013 (with Kevin Porter, Sari Fink, and Michael Buckley of Exeter Associates, and with B.-M. Hodge of NREL)

Survey of Variable Generation Forecasting in the West, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-54457, April 2012 (with Kevin Porter).

Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-54338, March 2012 (with Kevin Porter).

Long-Term Electricity Report for Maryland, prepared for the Maryland Department of Natural Resources Power Plant Research Program Pursuant to Executive Order 01.01.2010.16, December 2011, (with Steven Estomin, Kevin Porter, Christina Mudd, Emma Nicholson, Sari Fink, Michael Buckley, and Krista Ozarowski).

Alternative Energy Resource Market Assessment, National Association of Regulatory Utility Commissioners, A report for the Public Utility Commission of Ohio, September 2011 (with Kevin Porter of Exeter Associates, Inc., Ed Holt & Associates, Inc., and Sustainable Energy Advantage LLC)

Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities: Revised Edition, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-51263, March 2011 (with Kevin Porter).

A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations, National Renewable Energy Laboratory, NREL Report No. SR-5500-49880, February 2011 (with Kevin Porter, Sari Fink, and Christina Mudd).

The Relationship between Wind Generation and Balancing-Energy Market Prices in ERCOT: 2007–2009, National Renewable Energy Laboratory, NREL Report No. NREL/SR-5500-49415, November 2010 (with Kevin Porter and Emma Nicholson).

The Relevance of Generation Interconnection Procedures to Feed-in Tariffs in the United States, National Renewable Energy Laboratory, NREL Report No. NREL/SR-6A20-48987, October 2010 (with Kevin Porter and Sari Fink).

Transmission Cost Allocation Methodologies for Regional Transmission Organizations, National Renewable Energy Laboratory, NREL Report No. NREL/SR-550-48738, July 2010 (with Kevin Porter and Sari Fink).

Examples of Wind Energy Curtailment Practices, National Renewable Energy Laboratory, NREL Report No. NREL/SR-550-48737, July 2010 (with Kevin Porter and Sari Fink).

Status of Centralized Wind Power Forecasting in North America, National Renewable Energy Laboratory, NREL/SR-550-47853, April 2010 (with Kevin Porter).

"Bi-Monthly Transmission Updates," of the National Wind Coordinating Collaborative, Prepared for National Renewable Energy Lab, August 2009 - June 2010 (with Kevin Porter).

"Maryland Power Plants and the Environment: A Review of the Impacts of Power Plants and Transmission Lines on Maryland's Natural Resources, Maryland Power Plant Research Program, PPRP-CEIR-15," January 2010 (with Steven Estomin, Christina Mudd, and Sari Fink of Exeter Associates, Inc. and contributing authors from Versar, Inc. and Environmental Resources Management).

"Wind Power and Electricity Markets," Compiled for the Utility Wind Interest Group, August 2009 (with Kevin Porter and Sari Fink).

Pike County Light And Power Company
Electric Division
Cost of Service
For the Future Test Year Ended September 30, 2025

Line No.	Description	Company Amounts at Present Rates	OCA Adjustments	Amounts After OCA Adjustments	Pro Forma Change in Revenues	Amounts After Change in Revenues
1	Total Operating Revenues	16,236,900	-	16,236,900	1,334,200	17,571,100
2						
3	Operating Expenses					
4	Purchased Electric Power Costs	7,964,400	-	7,964,400		7,964,400
5	Other Power Supply Expenses	771,600	-	771,600		771,600
6	Deferred Purchased Power Expense		-	-		0
7	Other O&M Expenses	3,447,700	(497,572)	2,950,128	3,700	2,953,828
8	Depreciation Expense	1,358,200	(133,500)	1,224,700		1,224,700
9	Taxes other than Income	1,016,400	-	1,016,400	78,718	1,095,118
10	Total Operating Expenses	$ 14,558,300	$ (631,072)	$ 13,927,228	$ 82,418	$ 14,009,646
11						
12	Operating Income Before Income Taxes	1,678,600	631,072	2,309,672	1,251,782	3,561,454
13	State Income Tax	(90,700)	183,733	93,033	100,017	193,050
14	Federal Income Tax	(219,400)	444,319	224,919	241,871	466,790
15						
16	Operating Income after Taxes	$ 1,988,700	$ 3,020	$ 1,991,720	$ 909,894	$ 2,901,614
17						
18	Rate Base	$ 39,033,539		$ 36,963,041		$ 36,963,041
19						
20	Rate of Return	5.09%		5.39%		7.85%

Pike County Light And Power Company
Electric Division
Summary of Revenue Increase at OCA Rate of Return
For the Twelve Months Ended September 30, 2025

Line No.	Description		Amount	Source
1	Adjusted Rate Base		$ 36,963,041	Schedule JLR-2, Page 1
2	Required Rate of Return		7.85%	Schedule JLR-18
3				
4	Net Operating Income Required		$ 2,901,599	
5	Net Operating Income at Present Rates		1,991,720	Schedule JLR-1, Page 1
6				
7	Income Deficiency/(Surplus)		$ 909,879	
8	Revenue Multiplier		1.4664	
9				
10	Required Change in Company Revenue		$ 1,334,200	
11				
12	Proposed Revenue Change		$ 1,334,200	
13	Less: Revenue Taxes	5.90%	$ 78,718	
14	Net of Revenue Taxes		$ 1,255,482	
15	Less: Uncollectibles	0.28%	$ 3,700	
16	Net of Uncollectibles		$ 1,251,782	
17	Less: State Income Tax @ 7.99%	7.99%	$ 100,017	
18				
19	Income Before Federal Taxes		$ 1,151,765	
20	Federal Income Tax @ 21.0%	21.00%	241,871	
21				
22	Net Income (Surplus)/Deficiency		909,894	

Note:
1/ Company Exhibit E-4, Summary, Page 2

Revenue Muliplier		Revenue Mulitplier
Additional Revenue		100.0000
Less: Revenue Taxes	5.90%	5.9000
Less: Uncollectibles	0.28%	0.280
		93.8200
Less: State Income Tax	7.99%	7.4962
		86.3238
Less: Federal Income Tax @ 0%	21%	18.1280
Retention Factor		68.196
		1.0000
		0.6820
		1.466366

Pike County Light And Power Company
Electric Division
Summary of Rate Base
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount per Company Filing [1/]	OCA Adjustments	Amount After OCA Adjustments
1	Utility Plant			
2	Electric Plant in Service	43,529,439	(2,175,000)	41,354,439
3	Common Plant in Service (Allocated)	1,532,400	(127,500)	1,404,900
4	General Plant allocated from Corning Gas (Net)	204,000		204,000
5	CWIP not taking interest	-		-
6	Total Utility Plant	$ 45,265,839	$ (2,302,500)	$ 42,963,339
7				
8	Utility Plant Reserves			
9	Accumulated Provision For Depreciation			
10	of Electric Plant in Service	5,411,400	(447,200)	4,964,200
11	Accumulated Provision For Depreciation			-
12	of Common Plant in Service (Allocated)	1,312,600	(79,050)	1,233,550
13	Retirement W.I.P	(63,200)	-	(63,200)
14	Total Utility Plant Reserves	$ 6,660,800	$ (526,250)	$ 6,134,550
15				-
16	Net Plant	38,605,039	(1,776,250)	36,828,789
17				
18	Additions to Net Plant			
19	Working Capital Requirements:			
20	Cash Working Capital	548,500	$ (15,848)	532,652
21	Materials and Supplies	1,568,400	-	1,568,400
22	Prepayments	26,500	-	26,500
23	Deferred Debits (Net of Tax)	302,100	(302,100)	-
24	Total Additions	$ 2,445,500	$ (317,948)	$ 2,127,552
25				
26	Deductions to Net Plant			
27	Deferred Credits (Net of Tax)	(91,900)	-	(91,900)
28	Customer Deposits	335,900	-	335,900
29	Accumulated Deferred Income Taxes	1,773,000	(23,700)	1,749,300
30	Total Deductions	$ 2,017,000	$ (23,700)	$ 1,993,300
31				
32	Electric Rate Base	$ 39,033,539	$ (2,070,498)	$ 36,963,041

Note:
[1/] Company Exhibit E-3, Summary Page 1

Pike County Light And Power Company
Electric Division
Summary of Rate Base Adjustments
For the Twelve Months Ended September 30, 2025

Line No.	Description	Source	Amount
1	Rate Base per Company Filing	Schedule JLR-2, Page 1	$ 39,033,539
2			
3	OCA Adjustments:		
4	Adjustment to Remove Post FTY Plant Additions	Schedule JLR- 5	(2,302,500)
5	Adjustment to Accumulated Depreciation	Schedule JLR- 6	526,250
6	Adjustment to Accumulated Deferred Income Taxes	Schedule JLR- 7	23,700
7	Adjustment to Deferred Debits: Rate Case Expense	Schedule JLR- 8	(192,440)
8	Adjustment to Deferred Debits: Storm Riley	Schedule JLR- 9	(109,660)
9	Adjustment to Cash Working Capital	Schedule JLR- 4	(15,848)
10	Total Ratemaking Adjustments		$ (2,070,498)
11			
12	Adjusted Rate Base per OCA		$ 36,963,041

Pike County Light And Power Company
Electric Division
Summary of Adjustments to Operating Income
For the Twelve Months Ended September 30, 2025

Line No.	Description	Operating Revenues	Purchased Electric Power Costs	Other Power Supply Expenses	Deferred Purchased Power Expense	Other O&M Expenses	Depreciation	Taxes Other Than Income	State Income Taxes	Federal Income Taxes	Operating Income
1	Amount per Company	$ 16,236,900	$ 7,964,400	$ 771,600	$ -	$ 3,447,700	$ 1,358,200	$ 1,016,400	$ (90,700)	$ (219,400)	$ 1,988,700
2											
3	OCA Adjustments:										
4	Adjustment to Depreciation Expense						(133,500)		10,667	25,795	$ 97,038
5	Adjustment to Intercompany Admin & Operating Charges: M&T Credit Card Charges					(170,000)			13,583	32,848	$ 123,569
6	Adjustment to Intercompany Admin & Operating Charges: Informtional Advertising					(4,708)			376	910	$ 3,422
7	Adjustment to Intercompany Admin & Operating Charges: Auditing					(47,888)			3,826	9,253	$ 34,809
8	Adjustment to Intercompany Admin & Operating Charges: Inflation Adjustment					(7,800)			623	1,507	$ 5,670
9	Adjustment to Minor Storms Expense					(265,816)			21,239	51,361	$ 193,216
10	Adjustment to Greater Pike Community Foundation Annual Dinner Expense					(1,360)			109	263	$ 988
13	Interest Synchronization								133,310	322,382	$ (455,692)
14											
15	Total OCA Adjustments	$ -	$ -	$ -	$ -	$ (497,572)	$ (133,500)	$ -	$ 183,733	$ 444,319	$ 3,020
16											
17	Total Adjusted Income Before Income Taxes	$ 16,236,900	$ 7,964,400	$ 771,600	$ -	$ 2,950,128	$ 1,224,700	$ 1,016,400	$ 93,033	$ 224,919	$ 1,991,720

Pike County Light And Power Company
Electric Division
Adjustment to Cash Working Capital
For the Twelve Months Ended September 30, 2025

Line No.	Description	Rate Year Amount Per Company [1/]	OCA Adjustments	Pro Forma Expense After OCA Adjustments	Company Daily Requirement	OCA AdjustedDaily Requirement	(Lead)/Lag Days [1/]	Company Dollar Days	OCA AdjustedDollar Days
1	Revenue Recovery	$ 15,878,371		$ 15,878,371	$ 43,502	$ 43,502	21	926,601	$ 926,601
2	Pennsylvania Gross Receipts Tax	995,500		$ 995,500	$ 2,727	$ 2,727	21	58,094	$ 58,094
3		16,873,871		16,873,871	46,230	46,230	21	984,694	984,694
4									
5	Purchased Power Expenses	7,964,400		$ 7,964,400	$ 21,820	$ 21,820	10	218,203	$ 218,203
6	SBC Expense	11,204		$ 11,204	$ 31	$ 31	30	921	$ 921
7	Salaries & Wages	482,104		$ 482,104	$ 1,321	$ 1,321	8	10,567	$ 10,567
8	401K Pension Match	31,902		$ 31,902	$ 87	$ 87	8	699	$ 699
9	Employee Welfare Expenses	423,591		$ 423,591	$ 1,161	$ 1,161	23	26,692	$ 26,692
10	Intercompany Charges	780,177	(230,396)	$ 549,781	$ 2,137	$ 1,506	30	64,124	$ 45,188
11	Uncollectible Accounts Accrual	47,247		$ 47,247	$ 129	$ 129	8	1,036	$ 1,036
12	Other O&M	1,686,876	(267,176)	$ 1,419,699	$ 4,622	$ 3,890	23	106,296	$ 89,461
13	Amortizations:	-		$ -	$ -	$ -		-	$ -
14	Storm Reserve	300,865		$ 300,865	$ 824	$ 824	-	-	$ -
15	Rate Case Costs	-		$ -	$ -	$ -	-	-	$ -
16	PUC Assessment	36,642		$ 36,642	$ 100	$ 100	-	-	$ -
17	Insurance	-		$ -	$ -	$ -	-	-	$ -
18	Depreciation & Amortization	1,358,200	(133,500)	$ 1,224,700	$ 3,721	$ 3,355	-	-	$ -
19	Taxes Other - Payroll	36,881		$ 36,881	$ 101	$ 101	8	808	$ 808
20	- Property Tax	18,338		$ 18,338	$ 50	$ 50	-	-	$ -
21	Pennsylvania Gross Receipts Tax	995,500		$ 995,500	$ 2,727	$ 2,727	-	-	$ -
22	Income Taxes:			$ -	$ -	$ -		-	$ -
23	Federal Income Tax	56,840	444,319	$ 501,159	$ 156	$ 1,373	30	4,672	$ 41,191
24	Deferred Federal Income Tax	60,213		$ 60,213	$ 165	$ 165	-	-	$ -
25	Corporate Business Tax (State)	26,544	183,733	$ 210,277	$ 73	$ 576	30	2,182	$ 17,283
26	Deferred State Income Tax	22,910		$ 22,910	$ 63	$ 63	-	-	$ -
27	Return on Invested Capital	1,122,700		$ 1,122,700	$ 3,076	$ 3,076	-	$ -	$ -
28	Total Requirement	15,463,134		$ 15,460,113			10	436,199	452,048
29									
30	Net Lag Days Per Company	11 [1/]							
31									
32	Per Company: Net Requirement	$ 548,495 [1/]							
33									
34	OCA Net Requirement	$ 532,647							
35									
36	OCA Adjustment to CWC	$ (15,848)							

Note:
1/ Company Exhibit E-3, Schedule 3, page 2.

Pike County Light And Power Company
Electric Division
Adjustment to Remove Post FTY Plant Additions
For the Twelve Months Ended September 30, 2025

Line No.	Plant In Service	Amount
1	*Electrice Plant In Service Post FTY Additions*	
2	Additions - October 1, 2025 through March 31, 2026	$ 2,300,000 [1/]
3	Retirements - October 1, 2025 through March 31, 2026	$ (125,000) [1/]
4	Net Additions	$ 2,175,000
5		
6	*Common Plant In Service Post FTY Additions - Electric Allocation 85%*	
7	Additions - October 1, 2025 through March 31, 2026	$ 200,000 [1/]
8	Retirements - October 1, 2025 through March 31, 2026	$ (50,000) [1/]
9	Net Additions	$ 150,000
10	Electric Allocation of Common Plant	85% [1/]
11		$ 127,500
12	Total Adjustment to Plant In Service	$ (2,302,500)

Notes
[1/] Exhibit E-3 Schedule 1.

Pike County Light And Power Company
Electric Division
Adjustment to Accumulated Depreciation
For the Twelve Months Ended September 30, 2025

Line No.	Plant In Service	Amount	
1	*Accumulated Provision for Depreciation of Electric Plant*		
2	Additions - October 1, 2025 thru March 31, 2026	$ 572,200	1/
3	Retirements - October 1, 2025 thru March 31, 2026	$ (125,000)	1/
4		$ 447,200	
5	*Accumulated Provision for Depreciation of Common Plant - Electric Allocation 85%*		
6	Additions - October 1, 2025 thru March 31, 2026	$ 143,000	1/
7	Retirements - October 1, 2025 thru March 31, 2026	$ (50,000)	1/
8		$ 93,000	
9	Electric Allocation of Common Plant	85%	1/
10		$ 79,050	
11			
12	Adjustment to Accumulated Depreciation	$ 526,250	

Notes
1/ Exhibit E-3 Schedule 2.

Pike County Light And Power Company
Electric Division
Adjustment to Accumulated Deferred Income Taxes
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount
1	Net Additions October 1, 2025 through March 31, 2026	$ 23,700 [1/]
2		
3	Adjustment to Rate Base	$ (23,700)

Note:
[1/] Company Exhibit E-3, Schedule 9

Pike County Light And Power Company
Electric Division
Adjustment to Deferred Debits: Rate Case Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount
1	Rate Case (a) Acct 186171	
2	Deferred Debit Balance as of September 30, 2025	$ 264,745 [1/]
3	Net of SIT & FIT Multiplier (1/1-28.8921%)	72.6879% [1/]
4	Company Proposed Amount Included in Rate Base	$ 192,440
5		
6	Adjustment to Rate Base	$ (192,440)

Note:
[1/] Company Exhibit E-3, Schedule 6

Pike County Light And Power Company
Electric Division
Adjustment to Deferred Debits: Storm Riley
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount	
1	Hurricane Riley Acct 05 186025		
2	Deferred Debit Balance as of September 30, 2025	$ 150,865	[1/]
3	Net of SIT & FIT Multiplier (1/1-28.8921%)	72.6879%	[1/]
4	Company Proposed Amount Included in Rate Base	$ 109,660	
5			
6	Adjustment to Rate Base	$ (109,660)	

Note:
[1/] Company Exhibit E-3, Schedule 6

Pike County Light And Power Company
Electric Division
Adjustment to Depreciation Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description	Electric Dist. Plant	Common Gen'l Plant Allocated	Total Electric
1	Depreciation Expense per OCA Recommendation			
2	Electric Distribution Plant in Service			
3	At September 30, 2024 Per Exhibit E-3, Schedule 12	34,737,197 [1/]	1,244,289 [1/]	35,981,486 [1/]
4	Less: Acquisition Adjustment	0 [1/]	0 [1/]	0 [1/]
5	Electric Plant at June 30, 2020	34,737,197 [1/]	1,244,289 [1/]	35,981,486 [1/]
6	Less: Non-Depreciable Plant	(1,087,646) [1/]	(264,350) [1/]	(1,351,996) [1/]
7	Depreciable Plant at June 20, 2020	33,649,551 [1/]	979,939 [1/]	34,629,490 [1/]
8	Additions - October 1, 2024 thru September 30, 2025			
9	Distribution - Completed CWIP at 9/30/2025	2,567,239 [1/]	0 [1/]	2,567,239 [1/]
10	Distribution / General Additions Plant	4,300,000 [1/]	510,000 [1/]	4,810,000 [1/]
11	**OCA Recommendation**			
12	**Additions - October 1, 2025 thru March 31, 2026**			
13	**Distribution / General Additions**	**0**	**0**	**0**
14	*Total Additions*	6,867,239	510,000	7,377,239
15	Retirements - October 1, 2024 thru September 30, 2025			
16	Distribution / General Plant	(250,000) [1/]	(85,000) [1/]	(335,000) [1/]
17	**OCA Recommendation**			
18	**Retirements - October 1, 2025 thru March 31, 2026**			
19	**Distribution / General Plant**	**0**	**0**	**0**
20	*Total Retirements*	(250,000)	(85,000)	(335,000)
21	Electric Depreciable Plant at September 30, 2025 [Formula per company]	40,766,790	1,574,939	42,341,729
22	**OCA Adjustment to Calculation of Electric Depreciable Plant at September 30, 202**	**40,266,790**	**1,404,939**	**41,671,729**
23	x Book Basis Average Composite Depreciation Rate	2.488% [1/]	15.866% [1/]	2.939%
24	Calculated Accruals to Depreciation Expense			
25	For The Twelve Months Ended September 30, 2025	1,001,800	222,900	1,224,700
26	Less: Depreciation Expense as of September 30, 2024	788,560 [1/]	308,390 [1/]	1,096,900
27				
28	*Increase In Depreciation Expense Per OCA Recommendation*	213,240	(85,490)	127,800
29				
30				
31	*Increase In Depreciation Expense Per Company*			261,300 [1/]
32				
33	Adjustment to O&M expenses			$ (133,500)

Note:
[1/] Company Exhibit E-4, Schedule 12 page 1.

Pike County Light And Power Company
Electric Division
Adjustment to Intercompany Admin & Operating Charges: M&T Credit Card Charges
For the Twelve Months Ended September 30, 2025

Line No.	Description	Total		85% - Electric Division
1	2024 Intercompany Admin & Operating Charges: M&T Credit Card Charges	202,824	1/	172,401
2	One-time intercompany reclass between Pike and Corning Natural Gas	200,000	2/	170,000
3	Subtotal less one-time reclass			2,401
4				
5	Adjustment to O&M Expenses			$ (170,000)

Note:
[1/] Company response to I&E-RE-1, "Q1 - E-4 Revenue Requirement - FINAL.xlsx", 'Intercompany Activity' tab
[2/] Company response to I&E-RE-42

Pike County Light And Power Company
Electric Division
Adjustment to Intercompany Admin & Operating Charges: Informtional Advertising
For the Twelve Months Ended September 30, 2025

Line No.	Description	Total		85% - Electric Division
1	2024 Intercompany Admin & Operating Charges: Informational Advertising	8,618	1/	$ 7,325
2				
3	2022 Intercompany Admin & Operating Charges: Informational Advertising	449	1/	
4	2023 Intercompany Admin & Operating Charges: Informational Advertising	171	1/	
5	2024 Intercompany Admin & Operating Charges: Informational Advertising	8,618	1/	
6				
7	Average 2022 through 2024	3,079		2,618
8				
9	Adjustment to O&M Expenses			$ (4,708)

Note:
1/ Company response to I&E-RE-16-D, "Intercompany allocations 2022-2024" Excel Attachment

Pike County Light And Power Company
Electric Division
Adjustment to Intercompany Admin & Operating Charges: Auditing
For the Twelve Months Ended September 30, 2025

Line No.	Description	Total		85% - Electric Division
1	2024 Intercompany Admin & Operating Charges: Auditing	87,342	[1/]	$ 74,241
2				
3	2022 Intercompany Admin & Operating Charges: Auditing	4,365	[1/]	
4	2023 Intercompany Admin & Operating Charges: Auditing	1,302	[1/]	
5	2024 Intercompany Admin & Operating Charges: Auditing	87,342	[1/]	
6				
7	Average 2022 through 2024	31,003		26,353
8				
9	Adjustment to O&M Expenses			$ (47,888)

Note:
[1/] Company response to I&E-RE-16-D, "Intercompany allocations 2022-2024" Excel Attachment

Pike County Light And Power Company
Electric Division
Adjustment to Intercompany Admin & Operating Charges: Inflation Adjustment
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount
1	Per Company: Intercompany allocations (excl. Payroll, Benefits, & Workers' Comp.) charged	
2	to O&M Expense for the Twelve Months Ended September 30, 2024	780,177 [1/]
3	Company Proposed Inflation Factor	1.00% [1/]
4	Company Proposed Adjustment	7,800
5		
6	Adjustment to O&M Expenses	$ (7,800)

Note:
[1/] Company Exhibit E-4, Schedule 10.

Pike County Light And Power Company
Electric Division
Adjustment to Minor Storms Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description	Balance At 9/30/2023	10/1/23 - 9/30/24	Balance At 9/30/2024	
1	Company Proposed Net Increase Per Exhibit E-4, Schedule 7			$ 29,700	1/
2					
3	Remove Minor Storms Expense from Company's Amortization Calculation				
4	Deferred Storm Balance				
5	- Riley	$ 541,921	$ (195,528)	$ 346,393	1/
6	- Minor Storms (future estimate)				
7		$ -	$ -	$ -	
8	Total	$ 541,921	$ (195,528)	$ 346,393	
9					
10	Amortization 10/1/24 - 9/30/25			$ (195,528)	
11	Unrecovered Balance at 9/30/2025				
12				$ 150,865	
13					
14	Recovery Period (Years)			4	1/
15					
16	Annual Amount to be Amortized			$ 37,716	
17					
18	Less: Annual amortization of Deferred Storm Charges				
19	In Twelve Months Ended September 30, 2024			$ (195,528)	
20					
21	Net Increase			$ (157,812)	
22					
23	Adjustment to Exhibit E-4, Schedule 7 Adjustement for Minor Storms Removal			$ (187,512)	
24					
25	New Minor Storms Expense Adjustment			Amount	
26	Pike Storm Work Orders Year Ended Sept 30, 2022			$ -	2/
27	Pike Storm Work Orders Year Ended Sept 30, 2023			$ 58,819	2/
28	Pike Storm Work Orders Year Ended Sept 30, 2024			$ 146,866	2/
29	Average			$ 68,562	
30					
31	Expense Adjustment			(78,304)	
32					
33					
34	Adjustment to O&M Expenses			$ (265,816)	

Note:
[1/] Company Exhibit E-4, Schedule 7.
[2/] Company response to OCA 11-8, "Pike Storm Work Orders" Excel attachment.

Pike County Light And Power Company
Electric Division
Adjustment to Greater Pike Community Foundation Annual Dinner Expense
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount	
1	Company Proposed Expense for Greater Pike Community Foundation Annual Dinner	$ 1,600	
2	Electric Division Allocation Percentage	85%	1/
3	Electric Division Allocation of Expense	1,360	1/
4			
5	Adjustment to O&M expenses	$ (1,360)	

Note:
1/ Company response to OCA 11-7

Pike County Light And Power Company
Electric Division
Interest Synchronization Adjustment
For the Twelve Months Ended September 30, 2025

Line No.	Description	Amount	
1	OCA Revised Rate Base	$ 36,963,041	[1/]
2	Weighted Cost of Debt	3.100%	[2/]
3	Adjusted Interest Deduction	$ 1,145,854	
4	Interest Deduction Per Company	2,814,318	[3/]
5	Adjustment to Synchronize Interest Expense	$ (1,668,464)	
6	Effective State Income Tax Rate	7.99%	
7	Adjustment to State Income Taxes	$ 133,310	
8	Federal Income Tax Base	$ (1,535,154)	
9	Federal Income Tax Rate	21.00%	
10	Adjustment to Federal Income Taxes	$ 322,382	

Notes:
[1/] Schedule JLR-2, Page 1.
[2/] Schedule JLR-18.
[3/] Company Exhibit E-4, Schedule 14, Page 3.

Pike County Light And Power Company
Electric Division
Calculation of Rate of Return
For the Twelve Months Ended September 30, 2025

Line No.	Description	Capitalization Ratio	Cost Rate	Weighted Cost
1	Long-Term Debt	40.81%	6.00%	2.45%
2	Short-Term Debt	8.66%	7.50%	0.65%
3	Total Debt	49.48%		3.10%
4				
5	Common Stock Equity	50.52%	9.40%	4.75%
6				
7	Total	100.00%		7.85%

Source:
Per Direct Testimony of OCA Witness Reno

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

VERIFICATION

I, Jennifer L. Rogers, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 3, 2025 Signature: Jennifer L. Rogers

Jennifer L. Rogers

Address: 10480 Little Patuxent Parkway, Suite 300,
Columbia, Maryland, 21044

OCA Statement No. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY OF

MAUREEN L. RENO

ON BEHALF OF THE

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

Dated: April 3, 2025

TABLE OF CONTENTS

DOCKET NO. R-2024-3052359
PIKE COUTY LIGHT & POWER – ELECTRIC RATE CASE
DIRECT TESTIMONY OF
MAUREEN L. RENO

EXHIBITS

- Exhibit MLR-1, Schedule MLR-1 – Historical Economic Trends (Percent Change from Previous Period)
- Exhibit MLR-1, Schedule MLR-2a – Interest Rates & Bond Yields (2018 to 2024)
- Exhibit MLR-1, Schedule MLR-2b – Daily Yields on Treasury Securities
- Exhibit MLR-1, Schedule MLR-2c – Daily Average TIPS Spread
- Exhibit MLR-1, Schedule MLR-3 – Survey of Professional Forecasters (U.S. Quarterly and Annual Forecasts)
- Exhibit MLR-1, Schedule MLR-4– Sample Characteristics
- Exhibit MLR-1, Schedule MLR-5a – Constant-Growth DCF Results EPS Growth Method (30-Day Stock Price)
- Exhibit MLR-1, Schedule MLR-5b – Constant-Growth DCF Results EPS, DPS, and BVPS Growth Method (30-Day Stock Price)
- Exhibit MLR-1, Schedule MLR-5c – Constant-Growth DCF Results with EPS Growth Method (90-Day Stock Price)
- Exhibit MLR-1, Schedule MLR-5d – Constant-Growth DCF Results with EPS, DPS, and BVPS Growth Method (90-Day Stock Price)
- Exhibit MLR-1, Schedule MLR-6a – Sustainable Growth DCF (Internal Growth Component)
- Exhibit MLR-1 ,Schedule MLR-6b – Sustainable Growth DCF (External Growth Component)
- Exhibit MLR-1, Schedule MLR-6c – Sustainable Growth DCF (Results) (30-Day Stock Price)
- Exhibit MLR-1, Schedule MLR-6d – Sustainable Growth DCF (Internal Growth Component)

- Exhibit MLR-1, Schedule MLR-6e – Sustainable Growth DCF (External Growth Component)
- Exhibit MLR-1, Schedule MLR-6f – Sustainable Growth DCF (Results) (90-Day Stock Price)
- Exhibit MLR-1, Schedule MLR-7a – CAPM Assumptions (Historical Large Stock Return, 30-yr T-Bond)
- Exhibit MLR-1, Schedule MLR-7b – CAPM Results (Historical Large Stock Return, 30-yr T-Bond)
- Exhibit MLR-1, Schedule MLR-7c – CAPM Assumptions (Supply-Side ERP, 30-yr T-Bond)
- Exhibit MLR-1, Schedule MLR-7d – CAPM Results (Supply-Side ERP, 30-yr T-Bond)
- Exhibit MLR-1, Schedule MLR-7e – CAPM Assumptions (D&P Normalized RF Rate)
- Exhibit MLR-1, Schedule MLR-7f – CAPM Results (D&P Normalized RF Rate)
- Exhibit MLR-1, Schedule MLR-8a – Electric Rate Cases for CY 2024
- Exhibit MLR-1, Schedule MLR-8b – Electric Rate Cases for CY 2023
- Exhibit MLR-1, Schedule MLR-8c – Electric Rate Cases for CY 2015-2025
- Exhibit MLR-1, Schedule MLR-8d – Electric Rate Cases for CY 2015-2025 (Only ROR rates higher than 7.85%)
- Exhibit MLR-2 (Pike Response to OCA Interrogatory 6-4).
- Exhibit MLR-3 (Pike Response to OCA Interrogatory 6-3: Supplemental Attachment Corning Energy Corporation Capitalization Structure).
- Exhibit MLR-4 (Pike Response to OCA Interrogatory 2-11: Supplemental Attachment Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024)).
- Exhibit MLR-5 (Pike Response to OCA Interrogatory 9-4).
- Exhibit MLR-6 (Pike Response to OCA Interrogatory 6-6).

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR FULL NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Maureen L. Reno. I am an economist with a specialization in public utility economics and finance. I am the founder and principal consultant of Reno Energy Consulting Services, L.L.C. My business address is 19 Hope Hill Road, Derry, New Hampshire 03038.

Q. PLEASE SUMMARIZE YOUR EDUCATION.

A. I received a Bachelor of Arts degree in Economics from the University of Maine at Orono, Maine in 1996. In 1998, I earned a Master of Arts degree in Economics from the University of New Hampshire in Durham, New Hampshire, where I also completed all course work and examination requirements for a Ph.D. degree in Economics, except for my dissertation. My areas of academic concentration included industrial organization and environmental economics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have 24 years of professional experience in the regulated utilities and energy sectors. From 2001 to 2011, I served as a utility analyst and program manager with the New Hampshire Public Utilities Commission, advising the Commissioners on regulated utilities' cost of capital and return on equity ("ROE"), among other regulatory matters. From 2011 to 2012, I served as a Senior Energy Economist with the Union of Concerned Scientists, advising on the intricacies of the regulated utility industry and helping to develop alternative financing programs for renewable energy investments. Since 2012, I have served as an independent consultant to multiple firms, including Exeter Associates, Inc. and TAHOEconomics, LLC on utility cost of capital, ROE, and capital structure; Stephenson Strategic Communications, LLC on federal climate and energy policy; and TrueLight Energy, LLC on regulated utility rate impacts and energy markets.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE A PUBLIC SERVICE COMMISSION?

A. Yes. My testimony was presented and accepted in 38 regulated utility proceedings in several states, including Alaska, Arizona, California, Delaware, Georgia, Kansas, Missouri, New Hampshire, New Mexico, North Carolina, Oklahoma, South Carolina and Texas, on a wide range of issues concerning regulated utilities, retail and wholesale energy markets, and renewable energy. (See Appendix A for my curriculum vitae and qualifications.)

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am serving as an expert witness on cost of capital, ROE, and capital structure on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into eight sections including this one. In Section II, I discuss the purpose of my testimony, which is to compare the rate of return ("ROR") proposed by Pike County Light and Power ("Pike" or "the Company") with the ROR that I am recommending. In Section III, I review current and near-term economic and financial conditions in the United States and Pennsylvania. In Section IV, I evaluate Pike's proposed capital structure and discuss my recommended capital structure. In Section V, I summarize Pike's proposed cost of debt. In Section VI, I discuss different types of risks for regulated electric utilities and evaluate whether Pike is facing greater or lesser risks than its peers in the proxy group that I use in my ROE analysis. In Section VII, I present my ROE analysis which includes the methodologies that I applied to develop my ROE recommendation. I also evaluate Pike's proposed ROE. Finally, in Section VIII, I summarize my recommendations concerning a fair and reasonable ROR, which includes my recommended capital structure and ROE.

II. PURPOSE AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to recommend an ROR for ratemaking purposes.[1] I recommend a different ROR—to include a different ROE—rather than that proposed by Pike. My ROE recommendation was determined in accordance with the standards identified in *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679, 692-93 (1923) ("*Bluefield*") and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944) ("*Hope*"). In *Bluefield* and *Hope*, the U.S. Supreme Court established the principle that a public utility may be allowed to earn a return comparable to a return on investments in other enterprises having similar risks that allow the utility, under efficient management, to maintain financial integrity so that it can attract capital on reasonable terms and maintain its credit.

Q. WHAT IS THE RATE OF RETURN THAT PIKE IS PROPOSING?

A. For the future test period ending September 30, 2025 ("FTY"), Pike proposed an ROR of 8.37%, which is composed of (1) a capital structure of 50.52% common equity, 40.81% long-term debt, and 8.66% short-term debt; (2) a cost of long-term debt of 6.80%; (3) a cost of short-term debt of 7.58%; and (4) an ROE of 9.75%.[2] See Table 1

[1] For the purpose of my testimony, I will utilize the term "rate of return," or ROR, which I consider to be synonymous with the terms "return on rate base" or "weighted average cost of capital."

[2] Lenns and Lenns Direct, at 18-21 and Exhibit E-2, Schedule 3 for the future test period ending September 30, 2025. The historical test period is October 1, 2023 through September 30, 2024.

at the end of this section of my testimony for a comparison of the proposed and recommended RORs.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED RATE OF RETURN?

A. No. The Commission should reject Pike's proposed ROR because of two main considerations. First, it is based on an overstated ROE that does not accurately reflect investors' current expected returns on utility stocks. Second, Pike's proposed electric system ROR of 8.37% is excessively high and inconsistent with the RORs typically allowed for distribution-only electric utilities.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED CAPITAL STRUCTURE?

A. Yes, subject to my concern about Pike's claimed ROR and my further recommendation discussed below. Pike's proposed equity ratio of 50.52%, based on the FTY ending September 30, 2025, is reasonable for determining its capital structure in the current proceeding. Pennsylvania precedent allows utilities to base their equity ratios on an FTY. Pike's proposed equity ratio of 50.52% is consistent with regulated utility sector trends and recently observed values for the Company. However, I have significant concerns regarding the reasonableness of Pike's ROR, and a higher equity ratio further amplifies these concerns.

Q. WHAT IS YOUR FURTHER RECOMMENDATION?

A. I further recommend that Pike's proposed FTY equity ratio of 50.52% be established as a maximum for the Company and that the Commission require Pike to actively manage its capital structure to prevent further increases in the equity ratio in future years.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED COST OF LONG-TERM DEBT?

A. No. While Pike's long-term debt costs appear to be based on the Company's embedded cost of long-term debt, I am concerned that the proposed 6.80% cost of long-term debt is excessive and not consistent with market rates during the time of each debt issuance. Pike's management has a responsibility to effectively manage long-term debt costs, and ratepayers should not bear the burden of any failure to do so.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED COST OF SHORT-TERM DEBT?

A. No. Pike's management has a responsibility to effectively manage short-term debt costs but has failed to do so. While Pike's short-term debt costs appear to be based on the Company's embedded cost of short-term debt, the individual short-term debt costs are inconsistent with market rates during the time of each debt issuance.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED ROE?

A. No. The 9.75% ROE proposed by Pike witnesses Chuck Lenns and Matthew Lenns does not comport with current market trends and the return on equity investors expect for a stock from a similar-risk distribution-only electric utility.

Q. WHAT EVIDENCE DOES PIKE PRESENT TO SUPPORT ITS RECOMMENDED ROE OF 9.75%?

A. Witnesses Lenns and Lenns did not conduct their own analysis using industry-standard ROE models, such as the Discounted Cash Flow ("DCF") Model and the Capital Asset Pricing Model ("CAPM"). Instead, in their testimony, they stated that they simply rounded the ROE from the Electric Distribution System Improvement Charge ("DSIC") Eligible Utilities Return on Equity Summary, as published for September 18, 2024.[3]

In response to OCA Discovery Set 6, Question 4, Mr. Matthew Lenns referenced page 15 of 30 of the *Report of the Quarterly Earnings of Jurisdictional Utilities for the Year Ended June 30, 2024* ("QE Report Ended June 30, 2024") issued by the Commission's Bureau of Technical Utility Services ("TUS") and provided a copy of the same. However, the QE Report Ended June 30, 2024 depicts the allowed ROE for Pike (electric) as 9.90%.[4] Given that the Company's claimed ROE of 9.75% is inconsistent with the 9.90% ROE set forth in the QE Report Ended June 2024, it is unclear what the witnesses mean by "rounding" to determine their proposed ROE. While this inconsistency is relevant, as it shows a lack of analysis to support the Company's claimed ROE, what is even more important is that the witnesses' proposed ROE does not reflect current market trends or investor expectations for a comparable distribution-only electric utility.

---

[3] Lenns and Lenns Direct, at 20-21.

[4] Exhibit MLR-2 (Pike Response to OCA Interrogatory 6-4); and
See QE Report Ended June 30, 2024, at 15, *available at* https://www.puc.pa.gov/pcdocs/1852340.pdf (last visited March 29, 2025).

Q. HAS THE BUREAU OF TECHNICAL UTILITY SERVICES ISSUED A NEW QUARTERLY EARNINGS REPORT SINCE PIKE SUBMITTED ITS FILING?

A. Yes. On February 6, 2025, TUS issued the latest edition of the *Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2024* ("QE Report Ended September 30, 2024").[5]

Q. DID THE BUREAU OF TECHNICAL UTILITY SERVICES ADJUST ITS COMMISSION-APPROVED ROE FOR DSIC-ELIGIBLE UTILITIES FOR PIKE?

A. Yes. The QE Report Ended September 30, 2024 shows a DISC ROE for Pike of 10.00%.[6]

Q. DO YOU AGREE WITH PIKE'S PROPOSED ROE?

A. No. Neither Pike's proposed ROE of 9.75%, which is based on the QE Report Ended June 30, 2024, nor the ROE of 10.00% set forth in the QE Report Ended September 30, 2024 is reflective of investors' expected ROE for a distribution-only electric utility in a low-risk regulatory environment.

Q. WHAT DO YOU RECOMMEND AS THE APPROPRIATE ROR FOR PIKE?

A. For Pike (electric), I recommend an overall ROR of 7.85%, which is composed of (1) a capital structure of 50.52% equity, 40.81% long-term debt, and 8.66% short-term debt (no difference from the Company's claim); (2) a cost of long-term debt of 6.00% and a cost of short-term debt of 7.50% (different from the Company's claim);[7] and (3) an

---

[5] *See* QE Report Ended September 30, 2024, at 15, *available at* https://www.puc.pa.gov/pcdocs/1865077.pdf (last visited March 29, 2025).

[6] Id., at 15.

[7] Most jurisdictions do not permit the inclusion of short-term debt in determining an allowed ROR. However, Pennsylvania does allow its inclusion, and therefore, I find it reasonable for Pike to include short-term debt for the purposes of this proceeding.

ROE of 9.40% (again, different from the Company's claim). See Table 1 below for a comparison of the proposed and recommended RORs.

Q. WHY SHOULD THE COMMISSION ACCEPT YOUR RECOMMENDED ROE?

A. My ROE recommendation of 9.40% is based on the rounded midpoint of my DCF results (9.39%) and falls within my ROE range of 8.44% to 10.34%. I recommend an ROE based on the midpoint of my DCF range because it represents a fair and reasonable ROE for Pike (electric) in consideration of its risks and investors' current valuation of public utilities and equity assets in general. I discuss my modeling in greater detail further below in my testimony.

Q. DID YOU EMPLOY ANY OTHER MODELS WHEN ESTIMATING YOUR ROE RESULTS?

A. Yes. I also use the CAPM as a check on the reasonableness of my DCF results; however, my recommended ROE is not based on the CAPM results. I use the CAPM to estimate a range of ROE results of 8.20% to 11.44%, with a midpoint of 9.82%. This midpoint of CAPM results is 43 basis points greater than my DCF midpoint. As noted, these CAPM results serve as a check on my DCF results to show that my recommendation based on the DCF model is reasonable and should be accepted by the Commission.

Q. HAVE YOU PREPARED A TABLE THAT COMPARES PIKE'S REQUESTED ROR TO THE ROR THAT YOU RECOMMEND?

A. Yes. See Table 1 on the next page.

TABLE 1. COMPARISON OF PROPOSED & RECOMMENDED RATES OF RETURN

	PIKE WITNESSES LENNS & LENNS			OCA WITNESS RENO		
	Weight	**Cost of Capital**	**Weighted Cost**	**Weight**	**Cost of Capital**	**Weighted Cost**
Long-Term Debt	40.81%	6.80%	2.78%	40.81%	6.00%	2.45%
Short-Term Debt	8.66%	7.58%	0.66%	8.66%	7.50%	0.65%
Common Equity	50.52%	9.75%	4.93%	50.52%	9.40%	4.75%
Total Capital Structure	100.00%		8.37%	100.00%		7.85%

Amounts may not add up due to rounding.
Source: Exhibit E-2, Schedule 3.

III. MACROECONOMIC AND FINANCIAL MARKET CONDITIONS

Q. WHY IS IT IMPORTANT TO CONSIDER MACROECONOMIC CONDITIONS IN DEVELOPING A RECOMMENDED ROE, COST OF DEBT, AND ROR?

A. I present current and expected macroeconomic conditions in this section to set the context for my ROE, cost of debt, and resulting ROR recommendations to the Commission. With respect to the expected ROE, investors evaluate both economic and monetary conditions when assessing the opportunity costs of their investments. Global, national, and regional economic conditions affect investor expectations regarding investment returns, as measured by stock prices, interest rates, and sustainable dividend growth — each of which serves as inputs I use in my DCF and CAPM analyses. Additionally, investors closely monitor market interest rates and the return on fixed-income securities, in particular U.S. Treasury bonds, as they weigh alternative investment options when making capital allocation decisions. The cost of new debt issuances is also determined according to the expectations set by bond holders.

Q. HOW ARE INTEREST RATES ON FIXED-INCOME SECURITIES DETERMINED?

A. Interest-rates or bond yields on long-term bonds are determined by investors' expectations on economic growth and inflation over the duration of the term of a particular bond. Interest rates on short-term bonds are also determined by these expectations but are largely driven by actions by the U.S. Federal Reserve Bank ("Federal Reserve"), specifically the Federal Open Markets Committee ("FOMC"), by adjusting the Federal Funds Rate (the overnight interest rate it charges commercial banks) and buying or selling U.S. Treasury securities to meet certain policy objectives.

Q. PLEASE ELABORATE ON THE FEDERAL RESERVE'S POLICY OBJECTIVES.

A. The Federal Reserve has two policy objectives: the first is to maintain full employment or the total amount of employment that the economy can experience without any overt inflationary pressures; and the second is to maintain a target rate of inflation of 2.0% over the long run.[8] Thus, the Federal Reserve monitors key economic indicators to gauge whether it is necessary to adjust the Federal Fund Rate to influence borrowing behaviors and/or adjust its balance of securities to change the level of money supply in the economy.

[8] https://www.federalreserve.gov/faqs/economy_14400.htm

Q. WHAT ECONOMIC INDICATORS DO BOTH THE FEDERAL RESERVE AND INVESTORS MONITOR?

A. The Federal Reserve and investors monitor economic indicators including measures of economic growth, such as real Gross Domestic Product ("GDP'), the unemployment rate, and measures of inflation, such as the Consumer Price Index ("CPI"), among others.

Q. HOW WOULD YOU DESCRIBE THE CURRENT STATE OF THE U.S. ECONOMY?

A. In general, economic signals show a slight slowdown in light of stubborn inflation, although inflation remains far lower than in 2022. Recent economic growth, as measured by real GDP, shows that the U.S. economy is slowing down after experiencing a post-COVID-19 pandemic rebound. Although inflation has fallen since it peaked in 2022, inflation is not falling at the rate the Federal Reserve had hoped. Therefore, there remains uncertainty regarding when the Federal Reserve will continue to decrease interest rates after reversing course of its aggressive increases in interest rates in July 2023.

Q. HOW HAS ECONOMIC GROWTH CHANGED SINCE THE COVID-19 PANDEMIC?

A. In 2021, real GDP growth reached an annual high of 6.1%, only to fall to 2.5% in 2022, rebound slightly to 2.9% in 2023 and 2.8% in 2024.[9]

[9] Council of Economic Advisers, "Economic Indicators" (January 2025), at 3.

Q. HOW HAS UNEMPLOYMENT CHANGED SINCE THE COVID-19 PANDEMIC?

A. Unemployment decreased from 5.3% in 2021 to 3.6% in 2022 and 2023. Unemployment has increased slightly to 4.0% in 2024.[10]

Q. HOW HAS INFLATION CHANGED SINCE THE COVID-19 PANDEMIC?

A. Inflation, as measured by the CPI, remains the primary concern in the economy, though it has decreased from its peak of 8.0% in 2022 to 2.9% in 2024.[11]

Q. HOW HAS THE FEDERAL RESERVE RESPONDED TO THESE ECONOMIC TRENDS?

A. Since July 2023, the FOMC has paused its campaign of aggressively increasing the federal funds to dampen stubborn inflationary pressures to reduce the amount of money circulating through the economy and drive down aggregate demand. Since then, the FOMC decreased the federal funds rate on three consecutive times in 2024. In its most recent press release issued on January 29, 2025, the FOMC states that "[r]ecent indicators suggest that economic activity has continued to expand at a solid pace. The unemployment rate has stabilized at a low level in recent months, and labor market conditions remain solid. Inflation remains somewhat elevated."[12] The FOMC continued by stating that although the risks to achieving its goal of maximum employment and 2% inflation are in balance, the economic outlook is uncertain. Thus, the FOMC decided to maintain the current target range for the federal funds rate at 4.25% to 4.50%.[13] The FOMC further stated, "[i]n considering the extent and timing

[10] Id., at 11.
[11] Id., at 24.
[12] Federal Open Market Committee, Federal Reserve Bank, "Press Release" (January 29, 2025), at 1.
[13] Id.

of additional adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks."[14] The FOMC also stated its intention to continue its reduction of holdings of U.S. Treasury securities, agency debt, and agency mortgage-backed securities.[15]

Q. HOW HAVE INVESTORS RESPONDED TO THESE ECONOMIC TRENDS?

A. According to *Value Line Investment Survey* ("*Value Line*"), this continued inflation is weighing on the consumer sector, which has powered the nation's economy the last few years and is now showing signs of fatigue with consumer spending, which fell 0.2% in January.[16] *Value Line* also notes that stock market volatility has picked up in light of continued uncertainty around the Trump Administration's tariff policies that threaten to increase prices in both the consumer and producer sectors and have resulted in stock market sell offs with each announcement.[17]

Q. HOW DO INVESTOR'S EXPECTATIONS INFLUENCE YOUR ROE RESULTS?

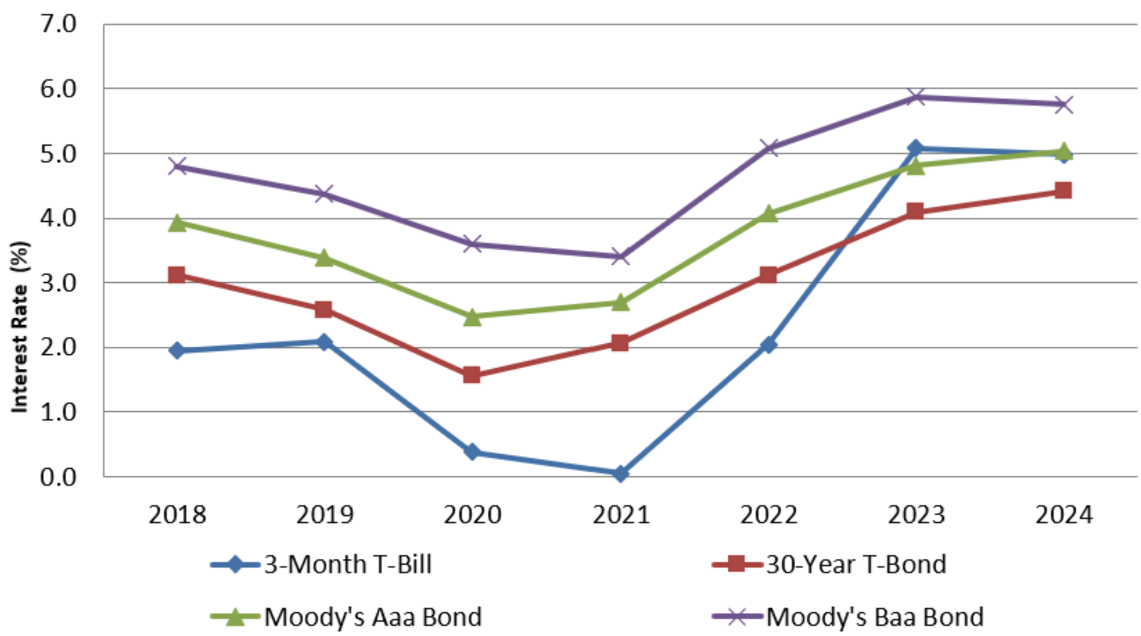
A. Investors consider action of the Federal Reserve and the economic conditions discussed above when estimating the opportunity cost of investing in a share of utility stock, or their expected return on equity in the long run. Thus, in addition to assessing economic growth, unemployment, and inflation, they will consider the yields or the return on fixed-income securities (e.g., interest rates on bonds), in particular interest rates on U.S. Treasury bonds.

[14] Id.
[15] Id.
[16] The Value Line Investment Survey, "Selection & Opinion", Issue 6, (March 14, 2025), at 2429.
[17] Id.

Q. HOW HAVE INTEREST RATES AND INVESTOR EXPECTATIONS CHANGED IN RECENT YEARS?

A. Figure 1 below shows how the interest rates have changed from 2018 to 2024. Yields on short-term U.S. Treasury bonds have currently peaked at elevated levels in response to the FOMC's recent actions. Yields on long-term U.S. Treasury bonds and corporate bonds also appear to have peaked.

FIGURE 1. INTEREST RATES AND BOND YIELDS (2018-2024)



Schedule MLR-2a (Interest Rates and Bond Yields (2018-2024)).

Yields on long-term bonds (reference the 30-Year Treasury Bond or "T-Bond," shown in red in Figure 1 above) rose from 2.06% in 2021 to 4.41% in 2024.[18] The cost of debt for Moody's Investors Service ("Moody's") Baa-rated corporations peaked in

[18] Council of Economic Advisers, "Economic Indicators" (January 2025), at 30.

2023 at 5.87% and fell slightly to 5.76% in 2024.[19] Moreover, short-term interest rates (reference the 3-Month U.S. Treasury Bill or "T-Bill," shown in blue in Figure 1 above) rebounded from 0.04% in 2021 to 4.98% in 2024.[20]

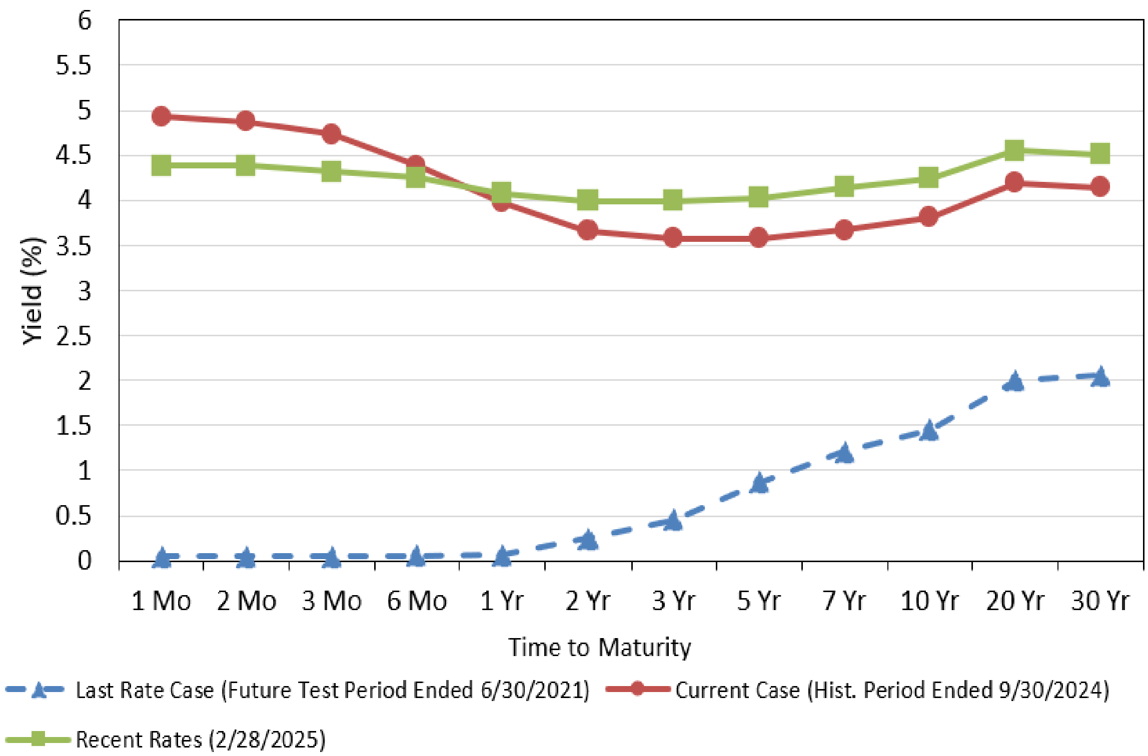
Short-term interest rates are primarily determined by the FOMC's policy actions. Recent decreases in short-term interest rates follow the FOMC's decrease in the Federal Funds rate and reduce its holding of Treasury and agency mortgage-backed securities to increase money supply.[21] Long-term interest rates are primarily determined by market forces, including investor expectations of future levels of inflation and economic growth.

Figure 2 below shows the yields on the different types of T-Bills and T-Bonds, with values along the horizontal axis representing the maturity of each T-Bill or T-Bond and the vertical axis showing the corresponding yield or interest rate. Each line represents the yields associated with each type of asset on a particular date and is referred to by financial analysts as the "yield curve." The yield curve reflects the bond market's consensus opinion of future financial market conditions as investors decide which bill or bond to purchase in response to expected levels of inflation and interest rates.

---

[19] Id.
[20] Id.
[21] Monetary Policy Report, February 2025.

FIGURE 2. TREASURY SECURITY YIELD CURVE



Source: www.treasury.gov

Q. HOW HAS THE YIELD CURVE CHANGED IN RECENT YEARS?

A. It is important to recall the evolution of the yield curve in recent years. During Pike's last rate case which incorporated a future test period ended June 30, 2021, the yield curve was upward-sloping with yields ranging from 0.05% for 1-month T-Bills to 2.06% for 30-year T-Bonds. The yields on short-term T-Bills were near 0% in response to FOMC actions, while the yields on some long-term T-Bonds were increasing slightly.

The shape of the yield curve has since flipped in 2024 and most recently flattened. As shown in Figure 2 below, yields on long-term T-Bonds are lower than the yields on short-term T-Bills as of September 30, 2024. This shows that investors were expecting a sustained economic slowdown and for the FOMC to shift its monetary policy to start decreasing interest rates to avoid an economic slowdown. However, the flattening yield curve for February 28, 2025 shows that yields on longer-term bonds are increasing while yields on short-term T-Bills are falling slightly, which suggests that investors may not be expecting an economic slowdown.

Q. WHAT OTHER MEASURES OF INVESTORS' EXPECTATIONS DO YOU CONSIDER?

A. Another metric by which to gauge investor expectations regarding long-term inflation is the Treasury Inflation-Protected Securities ("TIPS") spread, or the difference between yields on long-term nominal Treasury securities and long-term TIPS. The yield on a long-term conventional Treasury bond pays its holder a fixed nominal coupon and principal to compensate the investor for future inflation, and it includes the real rate of interest and inflation compensation. For TIPS, the coupons and principal both rise and fall with inflation, as measured by the CPI. The published yield includes only the real rate of interest. Therefore, the difference, roughly speaking, between the prevailing yields on these two types of Treasury securities reflects the inflation compensation over that maturity horizon that is expected by bond investors.

The 30-day average difference in the yield on the 30-year T-Bond and 30-year TIPS for the period ended February 28, 2025 equals 2.34% and represents the market's most recent expectations of long-term inflation. In other words, this data confirms that investors are anticipating that the rate of inflation over the long term is expected to stabilize at a higher rate than the FOMC's goal of 2.0%, which may further feed fears that the FOMC may delay interest rate cuts.

Q. WHAT ARE THE EXPECTATIONS FOR THE U.S. ECONOMY IN THE NEAR FUTURE?

A. As the FOMC continues to pause reducing short-term interest rates in response to persistent inflation, forecasters have noted the projections in near-term economic growth are higher than previously forecasted figures. However, the economy is still expected to slow down in the near term and then hover around 2.0% in the longer term. Specifically, according to the Q1 2025 edition of *Survey of Professional Forecasters* published by the Federal Reserve Bank of Philadelphia, economic growth, as measured by real GDP, is expected to decrease from 2.4% during 2025 to 2.2% during 2026 and 1.8% during 2027. Long-run economic growth beyond 2027 is expected to hover near 2.0% in 2028.[22]

Over the next year, inflation is expected to decrease but remain near moderate levels, with the CPI remaining near 2.8% in 2025 and then falling to 2.6% in 2026 and 2.3% in 2027. Another inflation metric closely watched by the FOMC is the Personal Consumption Expenditures ("PCE") index because it represents a broader measure of inflation. The PCE is expected to decrease from 2.4% in 2025 to 2.3% in 2026 and 2.0% in 2027, matching the FOMC's monetary policy goal of inflation. The data also show that analysts expect the national unemployment rate to increase slightly from 4.2% in 2025 and 2026 to 4.3 in 2027 and 2028.[23]

[22] Federal Reserve Bank of Philadelphia, "Survey of Professional Forecasters: First Quarter 2025" (February 14, 2025), at 9 & 11.
[23] Id.

Q. HOW DOES THE PENNSYLVANIA ECONOMY COMPARE TO THE U.S. ECONOMY?

A. Pennsylvania's economy is stronger than the national economy. Pennsylvania's real GDP for the most recent quarter for which data is available (Q3 2024) is 3.9% compared to the national average of 3.2%.[24] Personal income also grew at a faster rate than the national average over the same period, with an increase of 3.9% compared to the U.S. average of 3.2%.[25] Pennsylvania's unemployment rate of 3.6% in 2024 was lower than the national unemployment rate of 4.0%, though the Pennsylvania county of Pike County had a higher unemployment rate at 4.3%.[26]

According to the Federal Reserve Bank of Philadelphia, the regional economy declined slightly in 2025 after edging up in the prior period. Employment continued to grow somewhat, although firms were more reluctant to hire workers amid economic uncertainty. Reported nonauto sales showed little or no change in consumer spending on balance but noted that sales to low-income consumers are trading down as they continue to be burdened by high prices, while auto sales increased slightly.[27]

Q. ARE INVESTORS AWARE OF PENNSYLVANIA'S ECONOMIC CONDITION?

A. Yes. Investors consider local, regional, and national economic conditions when making their investment decisions. For example, investors often compare Pike to its affiliates in other states that have similar or lower credit ratings.

---

[24] Bureau of Economic Analysis, "Gross Domestic Product by State and Personal Income by State, 3rd Quarter 2024" (December 20, 2024), available at https://www.bea.gov/news/2024/gross-domestic-product-state-and-personal-income-state-3rd-quarter-2024

[25] Id.

[26] www.bls.gov/news.release/pdf/srgune.pdf and https://fred.stlouisfed.org/series/PAPIKE3URN

[27] Federal Reserve System, "The Beige Book: Summary of Commentary on Current Economic Conditions by Federal Reserve District" (February 2025), at 13-16.

Q. HOW DO INVESTORS VIEW UTILITY STOCKS?

A. In general, investors view utility stocks as a safe investment, especially during times of uncertainty, because of the industry's defensive fundamentals and high dividend yields. Utility stocks are considered defensive by investors because electric service is essential, and utilities are regulated monopolies. *Value Line* reports that during the past 12 months, utilities under its coverage have increased 14.9% in value on average versus a 14.7% rises in the *Value Line Arithmetic Index*. According to *Value Line*, this defensive group had recovered nicely through much of 2024, supported by recession concerns and falling interest rates. However, as fears of an economic downturn have abated recently and bond yields have crept up, utilities are underperforming. Specifically, *Value Line* reports that utility stocks have decreased 4.1% in value over the last three months compared to the 3.5% increase in the S&P 500.[28] 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.

Q. HOW DO INVESTORS' EXPECTATIONS OF AN ECONOMIC SOFT LANDING RELATE TO PIKE'S ROE?

A. As discussed previously in this testimony, despite a slight reprieve in inflation earlier last year, inflation has increased again, causing the Federal Reserve to delay any changes in its monetary policy. Persistent high interest rates are contributing to lower economic growth. Although the stock market performed well throughout 2024, investors seem to be anxious about when the FOMC will resume decreasing interest rates. Furthermore, investors are growing weary of the uncertainties regarding the

[28] Value Line Investment Survey, "Electric Utility East" (February 7, 2025), at 128.

Trump Administration's tariffs on imports across many goods from multiple countries—inducing fears of yet higher inflation and plummeting consumer confidence. Given this uncertainty, investors may choose more defensive stocks, such as utility stocks, that typically have a lower expected return compared to higher-risk stocks. This trend is demonstrated by my cost of equity study estimates.

IV. <u>CAPITAL STRUCTURE</u>

Q. WHAT IS MEANT BY THE TERM "CAPITAL STRUCTURE"?

A. Capital structure refers to the relative percentage of equity, preferred stock, and debt that a company uses to finance its investments.

Equity (or common equity) represents ownership in a company and its investments. It includes common stock, retained earnings, and additional paid-in capital. Equity financing is more expensive than debt financing for two reasons. Because companies have a legal obligation to pay debt before equity, stockholders expect a higher return to compensate for this risk. In addition, returns on equity (or dividends) are not tax deductible as a business expense like a company's interest payments on debt.

Preferred stock is a type of stock that offers greater benefits than common equity. Preferred stockholders receive a fixed dividend and have priority for payment over common stockholders.

Debt represents liabilities on a company's books that must be repaid prior to any common or preferred stockholders receiving a return on their investment. Corporate debt generally includes two time horizons: (1) long-term debt that matures over a period of more than one year; and (2) short-term debt that matures within one year.

Q. HOW IS A UTILITY'S TOTAL RATE OF RETURN CALCULATED?

A. The total rate of return is composed of the weighted costs of long-term debt and equity capital. Long-term debt costs are typically computed using the utility's actual debt costs as of a certain date, such as the last day of the test year. In some jurisdictions, such as Pennsylvania, short-term debt is typically included in the capital structure for ratemaking purposes. Unlike the debt components of the capital structure, equity cost rates must be estimated.

The utility's total ROR is developed by multiplying the percentage of each type of financing (common equity, long-term debt, and short-term debt) by their specific cost rates and then totaling the results for a total after-tax ROR. This rate is then converted to pre-tax returns by grossing up the common equity and the preferred stock dividends for taxes. The final pre-tax return is then multiplied by the utility's rate base to determine the amount of money that customers must pay to the utility for the return on investment and associated tax payments.

Q. HOW DOES THE CAPITAL STRUCTURE IMPACT THE TOTAL RATE OF RETURN?

A. The cost of equity is generally higher than the cost of debt, so ratepayers bear higher costs when the utility finances more of its rate base investment using common equity and preferred stock. As explained above, stockholders expect a higher return because companies are contractually obligated to repay their debt where no such obligation exists for equity. Additionally, equity is also more expensive than debt because debt financing is tax deductible while stock dividend payments are not. Thus, if a utility is allowed to use a capital structure for ratemaking purposes that has more equity than debt, ratepayers also pay a higher tax burden.

Q. HOW DO INVESTORS VIEW THE CAPITAL STRUCTURE?

A. On the one hand, investors may view a high reliance on debt as risky (referred to as financial or leverage risk) because debt has priority of payment over equity. Given that creditors must be paid before investors, a company's relatively high debt burden can lead to a higher required ROE relative to similar investment opportunities to accommodate the higher risk. On the other hand, excessive equity, while reducing financial risk for an enterprise's creditors and investors, increases the overall cost of capital (and therefore return on rate base), which must be recovered through rates for customers (giving rise to investor concern over affordability of utility rates in the context of macroeconomic inflation conditions).

Q. WHAT CAPITAL STRUCTURE IS PIKE REQUESTING FOR USE IN THIS CASE?

A. For the FTY ending September 30, 2025, Pike is proposing a capital structure of 50.52% common equity, 40.81% long-term debt, and 8.66% short-term debt.[29] This capital structure includes new financed long-term debt that Pike issued on September 12, 2024, with its parent entity, Corning Energy Corporation ("CEC"), in the amount of $17.584 million at a coupon rate of 6.31%. This capital structure also includes the daily short-term debt balance for the 12 months ended September 30, 2024 of $2,006,792 as a proxy for the short-term debt balance for the FTY.

Q. WHAT IS PIKE'S CURRENT CAPITAL STRUCTURE?

[29] Lenns and Lenns Direct, at 18-21 and Exhibit E-2, Schedule 3. The test period is October 1, 2023 through September 30, 2024.

A. Pike's actual capitalization for the historical period ended September 30, 2024 is 44.69% long-term debt, 5.10% short-term debt, and 50.21% equity.[30]

Q. HOW HAS PIKE'S CAPITAL STRUCTURE CHANGED SINCE THE LAST RATE CASE?

A. Pike's equity ratio has gradually increased since the last rate case from 47.17% for year ended September 30, 2022 to 47.97% for year ended September 30, 2023 and 50.21% for year ended September 30, 2024.[31]

Q. WHY IS THIS INCREASE IN THE EQUITY RATIO OVER THE LAST THREE YEARS A CONCERN?

A. As noted above, as Pike's equity ratio increases, the financial burden on ratepayers increases because the cost of common equity is higher than the cost of long-term debt. In addition, dividend payments associated with equity must be made with after-tax funds, which are more expensive than pre-tax funds.

Q. SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED CAPITAL STRUCTURE?

A. Yes, subject to my concern about Pike's claimed ROR and my further recommendation discussed below. Pike's proposed equity ratio of 50.52%, based on the FTY, is reasonable for determining its capital structure in the current proceeding. Pennsylvania precedent allows utilities to base their equity ratios on an FTY. However, I have significant concerns regarding the reasonableness of Pike's proposed ROR, and a higher equity ratio further amplifies these concerns.

---

[30] Exhibit MLR-3 (Pike Response to OCA Interrogatory 6-3 Supplemental Attachment Corning Energy Corporation Capitalization Structure).

[31] Id.

I further recommend that Pike's proposed FTY equity ratio of 50.22% be established as a maximum. The Commission should require Pike to actively manage its capital structure to prevent further increases in the equity ratio in future years.

Q. WHY SHOULD THE COMMISSION ACCEPT PIKE'S PROPOSED CAPITAL STRUCTURE?

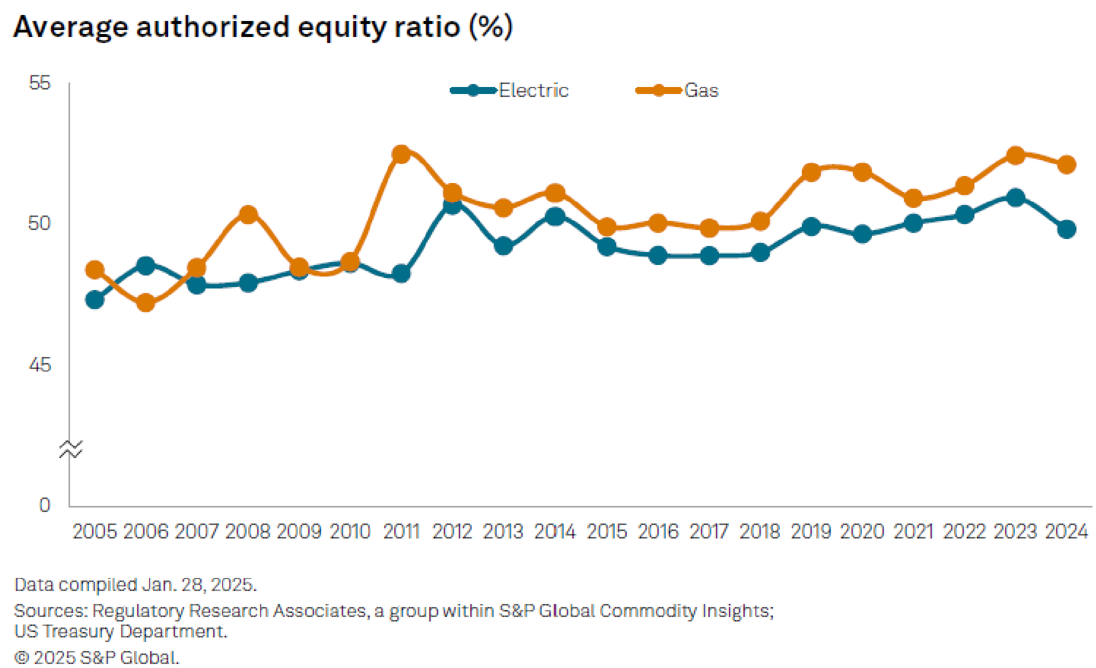
A. Pike's proposed equity ratio of 50.52% falls within the range of annual average equity ratios approved by regulatory commissions for regulated electric utilities since 2020, which are in the range of 49.67% to 50.95% (as shown in Figure 3 below).[32] For example, the average equity ratio approved by regulatory commissions for regulated electric utilities was 50.95% in 2023 and 49.84% in 2024.[33]

However, Pike's proposed equity ratio of 50.52% exceeds the proxy group average of 43.32% and median of 43.50% that is expected for 2025.[34]

---

[32] S&P Global Market Intelligence, "RRA Regulatory Focus - Major Energy Rate Case Decisions in the US January – December 2024" (February 4, 2025), at 6-7.
[33] Id.
[34] Exhibit MLR-1, Schedule MLR-4 (Sample Characteristics).

FIGURE 3. AVERAGE AUTHORIZED EQUITY RATIO



S&P Global Market Intelligence ("S&P MI"), "RRA Regulatory Focus - Major Energy Rate Case Decisions in the US – January – December 2024" (February 4, 2025) at 7.

Additionally, Pike's proposed equity ratio of 50.52% far exceeds the 25.73% equity ratio of its parent company, CEC.[35] The Commission needs to be aware that CEC would benefit from double leveraging, in which a parent company issues debt and then infuses that debt into the regulated subsidiary as common equity.

Q. PLEASE EXPLAIN THE CONCEPT OF DOUBLE LEVERAGE.

A. Double leverage occurs when a utility holding company issues debt and then infuses that debt into the regulated subsidiary as common equity. CEC as the holding company wholly owns the regulated utility subsidiary, Pike, and itself does not offer utility services. The purpose of the holding company issuing debt and infusing it into the utility subsidiary is to reduce costs to the parent company at the expense of the

[35] Exhibit MLR-3 (Pike Response to OCA Interrogatory 6-3 Supplemental Attachment Corning Energy Corporation Capitalization Structure).

subsidiary's ratepayers because equity is more expensive than debt. Also, equity is grossed up for taxes, such that the costs that CEC can collect from Pike, as the subsidiary, are far greater than the cost of issuing the debt.

V. <u>COST OF DEBT</u>

Q. WHAT DOES PIKE PROPOSE AS THE COST OF LONG-TERM DEBT?

A. Pike's proposed cost of long-term debt of 6.80% is the Company's embedded cost of debt for the FTY ended September 30, 2025, which is comprised solely of the $17.584 million intercompany loan from CEC to Pike, as refinanced on September 12, 2024, at a two-tranche blended rate of 6.31%.[36]

Q. DO YOU CONSIDER THE COMPANY'S REQUESTED OVERALL COST OF LONG-TERM DEBT REASONABLE?

A. No. 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%.

As shown earlier in Figure 1, interest rates followed a downward trajectory from 2018 through 2021 before experiencing a sharp increase. Pike's management had the option to refinance its long-term debt during this period but chose not to do so. This was a management decision, and it would be unreasonable for ratepayers to bear an undue cost burden due to Pike's delayed refinancing.

Pike only recently refinanced its long-term debt in 2024. Although interest rates have declined from their 2023 peak, they remain relatively high compared to historical values, as previously illustrated in Figure 1. For instance, current market rates for

[36] Lenns and Lenns Direct, Exhibit E-2; Schedule 2.

Moody's Baa-rated corporate bonds are around 6.00%, which is still lower than the 6.80% rate Pike is proposing as a reasonable cost of long-term debt in this proceeding.[37]

Q. DO YOU RECOMMEND THAT THE COMMISSION ACCEPT PIKE'S REQUESTED COST OF LONG-TERM DEBT?

A. No. The Company's proposed cost of debt of 6.80% is unreasonably high, primarily due to Pike's management decisions regarding the handling of long-term debt refinancing. Given the current financial circumstances, this rate is not justified.

Q. WHAT IS YOUR PROPOSED COST OF LONG-TERM DEBT LEVEL FOR PIKE IN THIS PROCEEDING?

A. I propose a 6.00% cost of long-term debt as a reasonable rate for Pike in this proceeding, as this reflects the current (2025) average interest rate for Moody's Baa-rated corporate bonds.[38]

Historical data shows that the cost of long-term debt for Moody's Baa-rated corporations was 4.80% in 2018, 4.37% in 2019, 3.60% in 2020, 3.40% in 2021, and 5.08% in 2022, peaking at 5.87% in 2023 before slightly declining to 5.76% in 2024, and at about 6.00% currently.[39]

Pike's management had the opportunity to refinance its long-term debt between 2018 and 2022 at lower interest rates but chose not to do so. Given this, the current cost of long-term debt for Moody's Baa-rated credits serves as an appropriate proxy for Pike's cost of debt and should be adopted by the Commission.

Q. WHAT DOES PIKE PROPOSE AS THE COST OF SHORT-TERM DEBT?

---

[37] Exhibit MLR-1, Schedule MLR-3 (Survey of Professional Forecasters).
[38] Id.
[39] Exhibit MLR-1, Schedule MLR-2a (Interest Rates & Bond Yields (2018 to 2024)).

A. Pike's proposed cost of short-term debt of 7.58% is the Company's cost on its short-term line of credit currently in effect.

Q. DO YOU RECOMMEND THAT THE COMMISSION ACCEPT PIKE'S REQUESTED COST OF SHORT-TERM DEBT?

A. No. The Company's proposed cost of short-term debt of 7.58% is unreasonably high; given the current financial circumstances, this rate is not justified. For instance, the current Prime interest rate is 7.50%.[40] This rate is used by commercial banks to determine interest on consumer loans, credit cards, and mortgages. Since a regulated utility has a less risky credit profile than a typical homebuyer, I use the Prime interest rate as a cap on the interest rate for short-term debt.

VI. RETURN ON EQUITY

Q. HOW DO YOU DETERMINE THE ROE FOR A REGULATED UTILITY?

A. For ratemaking purposes, the cost of equity must be estimated because it cannot be directly observed, and it varies with changing expectations of financial market conditions. The cost of equity is the long-term annualized market return that investors (in general) expect when they purchase equity shares of a particular company. It reflects the risk factors of that investment as compared to alternative investment opportunities and investors' current opportunity cost of investing in the securities of that company (i.e., the investors' risk-adjusted alternatives).

Because Pike is a wholly-owned subsidiary of Corning Energy Corporation, which is 100% owned by ACP Crotona Corporation, and is not a publicly traded company, it is not possible to directly apply cost of equity models to the Company. As

[40] Prime Rate | Federal Funds Rates Discount Rate Fed Fund Reserve Lending COFI

an alternative, I calculate an estimate of Pike's cost of equity by deriving average expected market returns for a proxy group of regulated electric utility companies with comparable risk.

Q. DID YOU CHOOSE THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. Yes. However, I decided to use the electric utility proxy group listed in the TUS QE Reports Ended June 30, 2024 for consistency given that Pike relies on that report for its proposed ROE.

Q. HOW DID YOU CHOOSE THE COMPANIES FOR YOUR UTILITY PROXY GROUP?

A. For my electric utility proxy group, I began with a group of 38 electric utilities that are publicly traded and included in *Value Line*. I then apply a series of criteria for my utility proxy group, which includes companies that have not publicly announced involvement in any major merger or acquisition activity; companies that have not cut or omitted their common dividends during the last six months; companies that are consistently covered by at least two utility industry equity analysts; and companies that have investment grade senior unsecured bond and/or corporate credit ratings (an S&P rating of BBB- or higher). After applying these criteria, I compiled a utility proxy group comparable to the proxy group used in the TUS QE Report Ended June 30, 2024.

Q. PLEASE DESCRIBE PIKE AND ITS OPERATIONS.

A. Pike is an electric and gas utility that provides electric service to approximately 4,900 customers and natural gas to 1,300 customers in eastern Pike County, Pennsylvania. Pike was acquired by CEC in 2016 from Orange & Rockland Utilities, Inc., a local utility company owned by Consolidated Edison.[41] Since Pennsylvania's electric industry was restructured in the late 1990s, Pike does not own its own electricity generation; it purchases electricity from other suppliers.[42]

Q. PLEASE DISCUSS THE DIFFERENT TYPES OF RISK THAT A REGULATED MONOPOLY, SUCH AS AN ELECTRIC UTILITY, MAY FACE.

A. An investor's expected return on an investment is composed of the risk-free rate and different types of risk, to include inflation risk, interest rate risk, business risk, financial risk, and regulatory risk.

The risk-free rate is the level of return investors can achieve without assuming any risk. In general, most investors agree that a Treasury bond is an asset perceived by the market as having relatively less risk than other market instruments because the federal government's access to tax proceeds to fulfill its debt obligations and strong credit rating make Treasury securities practically default-free. However, Treasury bonds are not absolutely risk-free because they incorporate a risk premium associated with interest rate risk. This is the premium investors require to compensate them for the foregone opportunity cost of an alternative, higher interest rate later.

From an investor's perspective, inflation risk, also called purchasing power risk, is the chance that the cash flows from an investment will not be worth as much in the future because of changes in purchasing power due to inflation.

---

[41] CEC was acquired by Argo Infrastructure Partners, LP in July 2022. Argo Infrastructure Partners, LP is an independent infrastructure investment manager that invests in industries such as regulated utilities, energy, renewables, and transportation. Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024), at 4.

[42] https://www.electricchoice.com/blog/guide-deregulation-pennsylvania/

Interest rate risk is the risk that arises for investors from the variability in returns caused by fluctuating interest rates, which depends on how sensitive an asset's price is to interest rate changes in the market. For bonds, for example, their price sensitivity to interest rates depends on the bond's time to maturity and the coupon rate of the bond.

Business risk, as perceived by investors, includes all the operating factors that increase the probability that expected future cash flows accruing to investors may not be realized. Business risk would include such factors as sales volatility and operating leverage. A utility's business risk is a function of factors such as customer base diversity, necessary capital expenditures, the regional and national economy, and the regulatory environment in which the utility operates.

Financial risk relates to the capital structure of a company, including its fixed contractual obligations and ability to pay interest on its debt and refinance that debt when it is due. Credit-rating agencies assess the financial health of a company through the use of key financial ratios that measure the extent to which a company can pay its debt, including principal and interest. Corporate rating designations that are commonly used are shown later in Table 2 of my testimony, which identifies rating categories used by S&P, Fitch, and Moody's for investment-grade issuances.

One of the key financial ratios used by credit-rating agencies is the debt ratio. The higher the portion of the capital structure that is comprised of debt or leverage, the higher the risk of default on those debt obligations.

Regulatory risk is based on the investor's perceived understanding of the current regulatory environment along with possible changes to that regulatory environment. How regulators treat regulatory lag is one example of regulatory risk. To the extent that companies face a time lag between incurring expenses and cost recovery, such risk is best measured by choosing a proxy group of companies that face similar regulatory oversight and earn the majority of their revenues from regulated operations.

A. INFLATION RISK

Q. IN YOUR VIEW, DOES PIKE FACE GREATER INFLATION RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. The risks associated with current inflation trends, which have decreased from a CPI of 8.0% in 2022 to 2.9% in 2024,[43] are shared by all regulated utilities and, as a result, are reflected in the utility proxy group's calculated costs of equity.

B. INTEREST RATE RISK

Q. IN YOUR VIEW, DOES PIKE FACE GREATER INTEREST RATE RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. Yes. Since changes in interest rates affect borrowing costs, the effect of such risk depends on the company's credit rating and portion of debt to total financial capital compared to the proxy group. As I discuss in greater detail in the financial risk section below, since Pike is not credit-rated and receives debt and equity funding through its parent company, CEC, the relevant comparison is CEC's credit rating. CEC has a lower credit rating than the average of the proxy group. Thus, Pike faces higher debt cost when issuing new debt compared with the debt costs incurred by one of the proxy group companies, on average.

C. BUSINESS RISK

[43] Exhibit MLR-1, Schedule MLR-1.

Q. HOW DO CREDIT-RATING AGENCIES VIEW ELECTRIC UTILITIES IN TERMS OF BUSINESS RISK?

A. Kroll Bond Rating Agency ("KBRA") characterizes CEC and its subsidiaries, including Pike's, business risk as "average" with the subcategory of industry risk considered "strong." KBRA reports that "The essential nature of the services provided and the nature of the regulatory protection in which the utility companies are granted natural monopolies with little competition in their service territories. In addition, the regulatory environment is typically supportive, allowing utility companies the opportunity to recover and earn a rate of return based on the costs to provide services."[44] KBRA also notes that CEC and Pike's competitive risk is considered "average" because "the company's monopolistic position through the ownership of regulated utilities operations, offset by its limited corporate scale and market share and concentrated customer base."[45]

Q. HOW DOES KBRA VIEW PIKE'S JOINT OPERATIONS IN THE ELECTRIC AND GAS UTILITY SECTORS?

A. KBRA looks favorably on Pike's diversified operations in both the distribution-only electric services and natural gas sectors, with both segments benefiting from long-term contracts for supply and a constructive regulatory environment, which I will discuss in greater detail later in this section. KBRA addresses Pike's long-term natural gas contracts and close proximity to the Marcellus gas fields as factors reducing Pike and its affiliates' exposure to industry risk.[46] KBRA also notes that CEC and Pike's natural

[44] Exhibit MLR-4 (Pike Response to OCA Interrogatory 2-11: Supplemental Attachment Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024)), at 6.
[45] Id.
[46] Id., at 8.

gas operations continue to grow as customers continue to switch to natural gas and the Commission remains supportive of natural gas use, while Pike affiliates in New York face challenges since the New York Public Service Commission has shifted its focus to the transition toward renewable energy sources.[47]

Q. IN YOUR VIEW, DOES PIKE FACE GREATER BUSINESS RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. The fundamental comparison here is to the proxy group. Every utility is different, but I do not believe that Pike has greater business risk than its peers in the proxy group.

D. <u>FINANCIAL RISK</u>

Q. IN YOUR VIEW, DOES PIKE FACE GREATER FINANCIAL RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. Pike faces similar financial risk compared to the proxy group. Although Pike acquires financing through its parent company, CEC, which has a lower credit rating than the proxy group, Pike's lower debt ratio relative to the proxy group reduces its financial risk. According to KBRA, CEC has an issuer credit rating of BB/Stable; a Series A Senior Secured Notes rated at BBB-/Stable; and a Series B Senior Secured Notes rating of BBB-/Stable.[48] In Pike Response to OCA Interrogatory Set 9, No. 4, the Company confirmed that the KBRA credit-rating scale is comparable to the credit-rating scale assigned by S&P.[49] Although CEC's ratings are lower than the average for the proxy group, which is an S&P rating of BBB+ and a Moody's rating of Baa2, KBRA classifies CEC liquidity and financial risk as average because CEC's liquidity

---

[47] Id., at 10.
[48] Id., at 3.
[49] Exhibit MLR-5 (Pike Response to Interrogatory OCA No. 9-4).

and cash flow profile is sufficient to meet its ongoing obligations. "The company [CEC]'s liquidity position is expected to benefit from the reimbursement of prudently managed costs and capital expenditures."[50] See Table 2 below for a comparison of CEC's credit ratings compared to the proxy group. Note that the proxy group average ratings are highlighted.

Table 2. Rating Categories
(Investment Grade)

S&P and Fitch	Moody's
AAA	Aaa
AA+	Aa1
AA	Aa2
AA-	Aa3
A+	A1
A	A2
A-	A3
BBB+	Baa1
BBB	Baa2
BBB-	Baa3

Q. DOES THE CAPITAL STRUCTURE OF PIKE INDICATE THAT IT IS EXPOSED TO LESS FINANCIAL RISK THAN OTHER MEMBERS OF THE PROXY GROUP?

A. Yes. Pike's current capital structure of 44.69% long-term debt and 5.10% short-term debt (totaling 49.79%) is lower than the utility proxy group's average debt-to-total-

[50] Exhibit MLR-4 (Pike Response to OCA Interrogatory 2-11: Supplemental Attachment Corning Energy Corporation: Unpublished Rating Report, KBRA Corporates, issued by Kroll Bond Rating Agency, LLC (September 12, 2024)), at 6.

capital ratio average of 56.23% and median of 55.75%, meaning that Pike faces lower financial or leverage risk than the proxy group.[51]

E. REGULATORY RISK

Q. IN YOUR VIEW, DOES PIKE FACE GREATER REGULATORY RISK THAN OTHER REGULATED UTILITIES IN THE PROXY GROUP?

A. No. Pike does not face greater regulatory risk than the proxy group. Pennsylvania has a regulatory ranking of "Above Average/2", according to S&P Market Intelligence, which is the second highest rating of "Above Average/1" and outranked by only Alabama.[52] In a more recent publication by Regulatory Research Associates ("RRA"), (a division of S&P Market Intelligence), RRA states that, "RRA views the regulatory climate for energy utilities in Pennsylvania to be relatively constructive from an investor standpoint…"[53] RRA continues by stating that the Commission allows utilities to employ a series of ratemaking practices meant to reduce regulatory lag, such as recovering costs using a forward-looking test year and year-end base valuations. The Commission also permits utilities to employ a series of rate mechanisms meant to recover costs in between general rate cases. Moreover, RRA notes that almost all the cases decided since the 1990s have been resolved by black box settlements that do not disclose the settled ROE or rate of return.

Q. PLEASE ELABORATE ON HOW A FUTURE TEST YEAR REDUCES REGULATORY LAG AND, ULTIMATELY, RISK.

---

[51] Exhibit MLR-1, Schedule MLR-4 (Sample Characteristics); and Exhibit MLR-3 (Pike Response to OCA Interrogatory 6-3 Supplemental Attachment Corning Energy Corporation Capitalization Structure).
[52] S&P MI, "RRA State Regulatory Evaluations – Energy" (January 2025), at 3.
[53] S&P MI, "Regulatory Research Associates: Focus Notes" (February 18, 2025) at 9-11

A. A future test year allows a utility to forecast costs forward into the first full year when the proposed new rates will be in effect so that rates can be matched to costs. It significantly reduces regulatory lag, which is the time between when a utility incurs increases in costs and when it recovers costs through increases in rates.

Q. HOW DOES REDUCING REGULATORY LAG REDUCE REGULATORY RISK?

A. Reducing the time or "lag" in between rate cases or when costs increase helps mitigate regulatory risk in several ways: It allows utilities to better align their revenues with current operating expenses, which in turn improves cash flow and enhances financial stability. By enabling more timely cost recovery, reducing lag also lowers uncertainty for investors, increasing the likelihood that a utility will achieve its authorized ROE without delay. Additionally, when rates more accurately reflect contemporaneous operating conditions, a utility can more effectively manage its expenses and maintain a sound financial position, ultimately reducing financial risk.

Q. HOW DO INVESTORS PERCEIVE THE USE OF FUTURE TEST YEARS?

A. Investors consider this type of test year to reduce regulatory risk, particularly in periods where there is a robust level of capital spending, high inflation, and rising interest rates.[54] S&P MI reports that less than a quarter of states allow a future test year.[55]

Q. IS THE REDUCTION IN REGULATORY RISK ASSOCIATED WITH A FUTURE YEAR ALREADY INCORPORATED IN YOUR ROE ESTIMATES?

A. No. I use the electric utility proxy group shown in the TUS QE Report Ended June 30, 2024, which includes utilities from across the country. As noted above, less than a

---

[54] S&P MI, "RRA State Regulatory Evaluations – Energy, Regulatory Research Associates" (May 24, 2023) at 18.

[55] *Id.*

quarter of states allow the use of future test years, so Pike's regulatory risk is arguably lower than the proxy group.

Q. DOES PIKE HAVE ANY RATE MECHANISMS THAT CAN IMPROVE COST RECOVERY IN BETWEEN RATE CASES?

A. Yes. Pike has a series of rate mechanisms or adjustment clauses that allow it to recover associated costs in between cases, thereby reducing recovery lag and regulatory risk. Such mechanisms also reduce business risk because they provide more predictable earnings and consistent cash flow than otherwise. These rate mechanisms include the Default Service Charge, State Tax Adjustment Surcharge, and DSIC.[56]

Q. PLEASE EXPLAIN THE PURPOSE OF THE DEFAULT SERVICE CHARGE.

A. The Default Service Charge is used to recover all costs associated with purchasing energy, capacity, and ancillary services incurred by Pike in providing electric power supply to default service customers. This charge consists of the market price of electric supply and the electric supply adjustment charge and are updated on a semi-annual basis.[57] This charge essentially shifts the risk associated with market price swings onto customers.

Q. WHAT IS THE PURPOSE OF THE STATE TAX ADJUSTMENT SURCHARGE?

A. The State Tax Adjustment Surcharge is recomputed whenever Pike experiences a material change in any of the taxes used in calculating the surcharge.[58]

---

[56] Exhibit MLR-6 (Pike Response to OCA Interrogatory 6-6).
[57] Id.
[58] Id.

Q. WHAT IS THE PURPOSE OF THE DSIC?

A. The DSIC is a surcharge that appears on consumer bills as a line item and that is used to recover the reasonable and prudent costs incurred by the utility to repair, improve, or replace eligible property that is placed in service in between rate cases, subject to certain customer protections. The DSIC permits Pike to recover eligible costs in between general rate cases and allows Pike to accelerate the replacement of aging infrastructure.[59]

Q. ARE THE ABOVE-REFERENCED RIDERS CURRENTLY IN EFFECT?

A. Yes.

Q. DO THESE RATE MECHANISMS REDUCE PIKE'S REGULATORY RISK?

A. Yes. Because the recovery in between rate cases is guaranteed for prudently incurred expenses, Pike's regulatory risk is comparable to the regulatory risk of other utilities in its proxy group.

Q. HOW DO INVESTORS VIEW THESE RATE MECHANISMS?

A. Investors view these rate mechanisms favorably because they reduce regulatory lag. As discussed above, S&P MI considers these rate mechanisms as constructive, but also looks at the frequency with which the adjustments occur and whether there is a true-up mechanism. S&P MI addresses the DSIC mechanism in particular as contributing to Pennsylvania's "Above average/2 rating," because it allows utilities to update rates for incremental infrastructure capital investment as often as quarterly.[60]

---

[59] Id.

[60] S&P MI, "RRA Regulatory Focus Notes: Pa. regulators raise electric, waters' proxy equity returns" (February 10, 2025).

VII. ROE METHODOLOGIES

Q. WHAT METHODOLOGIES DO YOU USE TO DERIVE YOUR COST OF EQUITY RECOMMENDATION?

A. I use the Constant-Growth DCF model to form the basis of my recommendation of a 9.40% ROE, which is the rounded midpoint (9.39%) of the range of my DCF results for Pike. My recommendation is further supported by the average of the results of my CAPM analyses of 9.82%, which is within the range of my DCF results, demonstrating the reasonableness of my DCF analysis.

Q. WHAT IS THE PREDOMINANT ROE MODEL UTILIZED BY REGULATORY BODIES IN THE UNITED STATES?

A. For decades, the FERC and public utility commissions across the United States, including Pennsylvania, have relied primarily on the DCF model to develop a range of returns earned on investments in companies with corresponding risks for purposes of determining the ROE for regulated entities.[61] Although I use variants of the Constant-Growth DCF model and the CAPM, I rely on my Constant-Growth DCF to form the basis of my recommendation of a 9.40% ROE for Pike.

A. CONSTANT-GROWTH DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE CONSTANT-GROWTH DCF MODEL.

A. The Constant-Growth DCF model is based on the dividend discount model first proposed by J.B. Williams in 1938.[62] The model is based on the premise that since cash dividends are the only income from a share of stock held to infinity, the value of that

[61] S&P MI, "RRA Regulatory Focus, FERC and Electric ROEs – 2022 Update" (September 26, 2022), at 3.
[62] J.B. Williams, *The Theory of Investment Value* (1938), at 45-48.

stock will be the present value of its stream of dividends, where the discount rate is the market's required return. The model can be modified to take into account the (more common) situation whereby shares of stock are bought and sold, producing capital gains income in addition to dividend income. To simplify the mathematics of the model, expected future dividends are represented by applying a constant-growth rate to the current observable dividend. Mathematically, the present value of an asset (common stock) is expressed as:

$$P_0 = \frac{D_1}{(K-g)},$$

Where:

D_1 is the dividend payment in one year from today or the expected dividend;
K is the rate of return used by investors to discount future dividends; and
g is the growth rate of the dividend payment.

The estimated cost of equity, K, is specified as:

$$K = \frac{D_1}{P_0} + g,$$

Where:

D_1 is the expected dividend, represented by $D_1 = D_0 (1 + g)$

Where:

D_0 is the current annual dividend per share.

Therefore, the market ROE capital is the sum of the dividend yield (anticipated dividend payments divided by the market price) and the expected growth in dividend income.

Q. PLEASE DESCRIBE HOW YOU DERIVE THE DIVIDEND YIELD COMPONENT OF YOUR DCF ANALYSIS.

A. The dividend yield in my DCF analysis is the annual dividend per share over the next 12 months, divided by the stock price average for different historical periods ended February 28, 2025. I first calculate the dividend yields using the 30-calendar day average of closing stock prices. I also use a 90-calendar day average of closing stock prices for capturing longer market trends.

In general, the most recent price of a security can be used to calculate the dividend yield because it represents current valuations in equity markets, calculating an average over time to mitigate any irregularities as necessary. However, using the average of a range of dates (e.g., 30 and 90 days) helps reduce the bias that might occur from day trading-driven irregularities or short-term volatility. The average 30-calendar day stock price for the proxy group is $71.68 per share, which is more than the 90-calendar day average stock price of $70.81 per share.[63]

I then estimate the expected dividend yield by applying the growth rate component of my Constant-Growth DCF analysis. I use three variants for calculating the growth rate component which I will discuss later in my testimony. These methods produce a range of expected dividend yields from 3.88% to 3.94% using the proxy group.[64]

Q. DO YOU MAKE ANY FURTHER ADJUSTMENTS TO YOUR EXPECTED DIVIDEND YIELD?

A. Yes. I adjust the dividend yield by one-half the expected growth to reflect growth over the coming year. Since I use annualized dividends, I make this adjustment to account for the fact that companies tend to announce changes in dividends at different times throughout the year.

[63] Exhibit MLR-1, Schedule MLR-5a through Exhibit MLR-1, Schedule MLR-6f.
[64] Id.

Q. PLEASE DESCRIBE THE GROWTH RATE COMPONENT OF YOUR DCF ANALYSIS.

A. My first set of growth rates is based on published earnings per share ("EPS") forecasts because investors typically view earnings growth as an indicator of future dividend growth. Investors also incorporate other sources of information when setting their expectations of dividend growth, which I will discuss shortly.[65]

I calculate the estimated earnings growth rates by taking the average of analysts' forecasts (which typically cover roughly the next five years) from *Value Line*, S&P MI, and Zacks. The S&P MI and Zacks websites report results incorporating forward-looking surveys of securities analysts' EPS projections. *Value Line*, in contrast, uses a historical base period average value for 2022-2024 and a forecast for 2028-2030 to calculate its growth rates, and it is not a survey. The average expected earnings growth rate using the proxy group of companies is 6.65% [and median DCF results of 10.22% and 10.34%].[66]

However, I then refine my calculation of the growth rate by averaging *Value Line's* dividends per share ("DPS") and book value per share ("BVPS") estimates with the previously estimated earnings growth rate projections weighted equally. I include these three components of growth in my analysis because investors are not only concerned with earnings growth but also dividend and book value growth as an assurance that dividend growth will be sustained. Moreover, dividend growth rates are more stable than expected earnings growth. These calculations produce an average growth rate of 5.34% [and median DCF result of 9.12% and 9.10%].[67]

[65] J.B. Williams, *The Theory of Investment Value* (1938), at 47.
[66] Exhibit MLR-1, Schedule MLR-5a and Exhibit MLR-1, Schedule MLR-5c.
[67] Exhibit MLR-1, Schedule MLR-5b and Exhibit MLR-1, Schedule MLR-5d.

B. SUSTAINABLE-GROWTH DISCOUNTED CASH FLOW MODEL

Q. DO YOU EMPLOY OTHER METHODS TO DERIVE GROWTH RATES IN YOUR DCF MODEL?

A. Yes. I also use the sustainable growth method to estimate the rate of dividend growth. The standard DCF model assumes only one source of equity financing, namely the retention of earnings. Growth in earnings and dividends, however, can also be achieved by the sale of new common equity.[68] The basic Constant-Growth DCF model of:

$$K = \frac{D_1}{P} + g$$

can be rewritten to assume that external sources of financing influence investor expectations of dividend growth, and is represented as the following:

$$K = \frac{D_1}{P} + br + sv$$

Therefore:

$$G = br + sv,$$

Where:

G is the retention growth rate;
b is the portion of retained earnings or 1 minus payout ratio;
r is the earned rate of return;
s represents the funds raised from the sale of stock as a fraction of existing common equity; and
v is the fraction of funds raised from the sale of stock that accrues to current shareholders.

[68] This expanded version of the DCF model allows for the value of stocks to vary from book values. If the stock prices equal book value, then the equity held by new shareholders is equal to the funds they invest and the existing shareholders' equity is not changed. If, however, stock prices are greater than book value, a portion of the funds accrues to the existing shareholders, thereby increasing their expectations of dividend growth in the future. David Parcell, *The Cost of Capital – A Practitioner's Guide* (2010), at 144-145.

I use *Value Line* expectations regarding retention ratios and ROEs for five years into the future to derive estimates for *b* and *r*, which in turn are used to calculate the expected internal growth component, *br*. To incorporate external financing growth, *sv*, I use *Value Line* data to derive the market-to-book ratio (which is an actual, observed figure) and expected growth in the number of outstanding shares. The average sustainable growth rates for my proxy group is 5.03% (30-calendar day stock prices) and 5.01% (90-calendar day stock prices).[69]

Q. DO YOU APPLY A REASONABLENESS SCREEN TO YOUR INDIVIDUAL ROE RESULTS USING THE DCF METHOD?

A. Yes. After adding the growth-rate estimates and the dividend-yield estimates for each company in my proxy group to obtain the individual ROE estimates, I examined individual company ROE results for reasonableness and whether some results are extreme outliers. Thus, in lieu of relying on the average of my proxy group results for each model, I use the median. The median is the middle value of a set of data and is not skewed by outliers.

Q. PLEASE SUMMARIZE YOUR DCF MODEL RESULTS.

A. As shown in Table 3 below, I employ three different methods for deriving the growth rate in the DCF model, yielding three sets of estimates of the ROE for my proxy group. First, I use the Constant-Growth DCF model using only EPS growth rates. When I assume that investors are only concerned with earnings growth when valuing a company's stock, thereby only using EPS growth in the DCF model, I derive ROE estimates of 10.22% (30-calendar day stock prices) and 10.34% (90-calendar day stock prices).[70]

[69] Exhibit MLR-1, Schedule MLR-6c and Exhibit MLR-1, Schedule MLR-6f.
[70] Exhibit MLR-1, Schedule MLR-5a and Exhibit MLR-1, Schedule MLR-5c.

Second, I use the Constant-Growth DCF model using EPS, DPS, and BVPS growth rates. Once I allow for other sources of growth, such as DPS and BVPS growth rates, to influence investors' expectations of the return on a particular equity, my analyses yield lower results. For instance, incorporating DPS and BVPS growth rates results in median ROE estimates of 9.12% (30-calendar day stock prices) and 9.10% (90-calendar day stock prices).[71]

Third, I use the Sustainable-Growth DCF model. When I allow for both internal and external funding sources to drive growth in investor income, for my sustainable growth rate model, I derive median ROE results of 8.44% (30-calendar day stock prices) and 8.50% (90-calendar day stock prices), after adjusting for reasonable growth rates.[72] The overall range of ROE estimates using my DCF is 8.44% to 10.34%, with a midpoint of 9.39%.

TABLE 3. RENO DCF RESULTS
(AVERAGE RESULTS)

Estimated Return on Equity	**ROE**		
DCF Methodology	30-Day Stock Price	90-Day Stock Price	Midpoint
Constant-Growth DCF (EPS Growth)	10.22%	10.34%	
Constant-Growth DCF (DPS, EPS and BVPS)	9.12	9.10	
Sustainable-Growth DCF	8.44	8.50	
DCF Range (Min. & Max.)[1]	**8.44%**	**10.34%**	**9.39%**

[1] ROE range (minimum and maximum values) for the 30-day and 90-day DCF results.

[71] Exhibit MLR-1, Schedule MLR-5b and Exhibit MLR-1, Schedule MLR-5d.
[72] Exhibit MLR-1, Schedule MLR-6c and Exhibit MLR-1, Schedule MLR-6f.

C. CAPITAL ASSET PRICING MODEL

Q. DO YOU USE ANY OTHER METHODOLOGIES TO ESTIMATE THE ROE FOR PIKE?

A. Yes. I also apply the CAPM to derive a total of three ROE estimates, which serve as a check on the reasonableness of my DCF results. However, my recommended ROE is not based on my CAPM results. My CAPM results range from 8.20% to 11.44% with a midpoint of 9.82%.

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is a version of the "risk premium" approach that is rooted in modern portfolio theory. It recognizes that common equity capital is riskier than debt from an investor's perspective because debt holders are typically paid before shareholders, and as such, investors require higher returns on stocks than on bonds to be compensated for the additional risk.[73] The cost of common equity is represented by the following equation:

$$K_e = R_f + \beta_s * RP,$$

Where:

K_e is the cost of equity;

R_f is the yield on risk-free securities;

β_s or Beta coefficient ("Beta") is a company-specific measure that reflects the movement in a company's stock price relative to movements in a composite group of companies representing the stock market. Beta measures the investment risk that cannot be eliminated by holding a diverse portfolio of assets; and

RP is the equity risk premium ("ERP") demanded by shareholders to accept equity relative to debt.

[73] The CAPM is generally superior to the simple risk premium method because the CAPM recognizes the risk of a particular company or industry through the use of betas, whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. PLEASE DESCRIBE THE RISK-FREE RATE YOU USE IN YOUR CAPM ANALYSIS.

A. The first term in the CAPM is the risk-free rate (R_f). I use the yield on the 30-year T-bond observed over a recent 30-day period ended February 28, 2025, of 4.70%, based on recent market information.[74] I also include in one of my CAPM analyses the Kroll (formerly Duff & Phelps) Normalized Risk-Free Rate of 3.50%.[75]

Q. HOW DO YOU CALCULATE THE EQUITY RISK PREMIUM?

A. In each of my three CAPM analyses, I use different estimates of the ERP that range from 5.00% to 7.17%. For the high end of this range, I use the Kroll estimate of the historical arithmetic average of real market returns over the period 1926 to 2023, which is the total return on common stocks (S&P 500) including capital appreciation, less the income returns on T-bond investments.[76]

Kroll also provides an updated Ibbotson & Chen supply-side model, which found that the market risk premium based on the S&P 500 was influenced by an abnormal experience of price-to-earnings ("P/E") ratios relative to earnings and dividend growth over the last 30 years. Thus, Kroll adjusted this market risk premium and published a long-horizon, supply-side ERP of 6.22%.[77]

Kroll also recommends a forward-looking ERP that was derived in conjunction with a normalized risk-free rate. Thus, my final CAPM analysis uses the Kroll Recommended U.S. ERP of 5.00% and Normalized Risk-Free Rate of 3.50%.[78]

---

[74] Federal Reserve, "Selected Interest Rates" (Daily), available at https://www.federalreserve.gov/releases/h15/.
[75] Kroll, "Cost of Capital in the Current Environment" (January 2025).
[76] Exhibit MLR-1, Schedule MLR-7a and Exhibit MLR-1, Schedule MLR-7b.
[77] Exhibit MLR-1, Schedule MLR-7c and Exhibit MLR-1, Schedule MLR-7d.
[78] Exhibit MLR-1, Schedule MLR-7e and Exhibit MLR-1,Schedule MLR-7f; Kroll, "Cost of Capital in the Current Environment" (January 2025).

Therefore, the estimated ERP used across my three CAPM methods ranges from 5.00% to 7.17%.

Q. HOW DO YOU ACCOUNT FOR THE VARIABILITY IN EQUITY MARKETS?

A. To capture investors' expected equity market returns, I focus on longer trends in stock market returns from 1928 to 2023. This period shows annual stock returns over multiple business cycles, avoiding the influence of any given period.[79]

Q. HOW DO YOU ADJUST THE EQUITY RISK PREMIUM TO ACCOUNT FOR COMPANY-SPECIFIC RISK?

A. I multiply company-specific betas by the ERPs to account for company-specific risk. I rely on *Value Line* betas because *Value Line* is widely used by the utility regulatory community and investment community in general. It is also known that *Value Line* adjusts its betas to account for the long-term tendencies of stocks to converge to a beta of one (1.0).[80] As a result, *Value Line* betas tend to have higher values than betas provided by some other sources. The average *Value Line* beta for the proxy group is 0.94. A beta value of 0.94 means that the stock price movement is less than the movement, in percentage terms, of the overall stock market. The price of an electric utility stock is, therefore, less volatile and less risky than the overall market.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?

[79] A business cycle typically includes an expansion and a recession that can vary in duration.

[80] Marshall Blume investigated the regression tendency of betas and reached the conclusion that betas have the tendency to approach a value of one (1) over time. That is, high-beta portfolios tend to decline over time toward one (1), while low-beta portfolios tend to increase to one (1). Marshall Blume, "Betas and Their Regression Tendencies," Journal of Finance (1975), at 785-796.

A. As shown in Table 4 below, applying the same risk-free rates, market risk premium, and betas from the proxy group, I estimate expected returns ranging from 8.20% to 11.44%.

TABLE 4. CAPM ESTIMATED ROE RESULTS

	ERP	Beta-Adjusted ERP	Risk-Free Rate	CAPM ROE	Max	Midpoint
CAPM (Hist. L-T ERP)	7.17	6.75	4.70	11.44%		
CAPM (Supply-Side ERP)	6.22	5.85	4.70	10.55%		
CAPM (Kroll Recommended ERP)	5.00	4.70	3.50	8.20%		
CAPM Range				8.20%	11.44%	9.82%

VIII. ROR AND ROE RESULTS SUMMARY

Q. PLEASE SUMMARIZE YOUR ROR RESULTS.

A. For Pike, I recommend an overall ROR of 7.85%, which is composed of (1) a capital structure of 50.52% equity, 40.81% long-term debt, and 8.66% short-term debt; (2) a cost of long-term debt of 6.00% and a cost of short-term debt of 7.50%; and (3) an ROE of 9.40%.

Q. HOW DOES YOUR PROPOSED ROR OF 7.85% COMPARE TO RECENT AND HISTORICAL ALLOWED ROR VALUES APPROVED BY REGULATORY COMMISSIONS ACROSS THE COUNTRY?

A. According to S&P MI, the average allowed ROR for distribution-only electric utilities in Calendar Year (CY) 2024 was 7.09%, with a median value of 7.09%, a minimum of

6.66%, and a maximum of 7.46%. For CY 2023, these values were slightly lower, with an average ROR of 6.65%.[81]

While I acknowledge that ROR values for different utilities are influenced by factors such as approved ROE level, capital structure, and cost of debt, it is noteworthy that my proposed ROR of 7.85%, if approved by the Commission, would be significantly higher than those recently authorized by other state regulators.

Looking at a broader historical perspective, over the 10-year period from January 1, 2015, through January 1, 2025, the average ROR awarded by state regulators has been 6.99% across 109 general rate cases for distribution-only electric utilities.[82] Notably, in this same period, there have been only five instances—out of 109 cases—where a state commission approved an ROR higher than my proposed 7.85%.[83]

By contrast, Pike's proposed ROR of 8.37% is inconsistent with recent regulatory precedent and exceeds the levels typically approved in the U.S. over the last decade. Over the past ten years, out of 109 rate cases in which a state regulator approved an ROR level, only one utility was granted an ROR exceeding 8.37%.[84] While my proposed ROR of 7.85% is undoubtedly high, it remains more reasonable than Pike's request. I urge the Commission to adopt my proposed ROR, as it better aligns with

---

[81] Derived from data provided by S&P MI, reflecting only distribution-only electric utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8a and Exhibit MLR-1, Schedule MLR-8b.

[82] Derived from data provided by S&P MI, reflecting only distribution-only electric utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8c.

[83] For the rate cases of: Fitchburg Gas and Electric Light Company, Inc., Massachusetts Department of Public Utilities (DPU) Docket 15-80, Fitchburg Gas and Electric Light Company, Inc. Massachusetts DPU Docket 15-809-130, Unitil Energy Systems, Inc. New Hampshire Public Utilities Commission (PUC) Docket No. DE-16-384, Jersey Central Power & Light Company, New Jersey Board of Public Utilities (BPU), Docket No. ER-12111052, Texas-New Mexico Power Company, Public Utility Commission of Texas (PUC) Docket No. 48401 (Derived from data provided by S&P MI, reflecting only distribution-only electric utilities for which S&P MI reported an ROR value. See Exhibit MLR-1, Schedule MLR-8d).

[84] For the rate case of Fitchburg Gas and Electric Light Company, Inc. (DPU Docket 15-80), the DPU granted the utility an approved ROR of 8.46%.

recent regulatory trends while still accounting for the necessary financial considerations related to Pike.

Approving an ROR that significantly deviates from historical norms risks setting a precedent that could lead to unjustified rate increases for consumers and undermine regulatory consistency. A balanced approach—one that recognizes financial needs of Pike while staying grounded in recent precedent—is the best path forward for the Commission.

Q. PLEASE SUMMARIZE YOUR ROE RESULTS.

A. As shown in Table 5 below, my ROE recommendation of 9.40% is the rounded midpoint of my DCF results (9.39%) and falls with my DCF range of 8.44% to 10.34% and represents a fair and reasonable ROE for Pike for the reasons I have previously discussed. The minimum of my range is the minimum of my DCF results, and the maximum of my range is the maximum result derived from my DCF results. Moreover, my recommendation of 9.40% should be accepted as reasonable because it is only 42 basis points lower than the average of my CAPM results.

TABLE 5. ROE ESTIMATES (%)

DCF Methodology	30-Day Stock Price	90-Day Stock Price	Midpoint
Constant-Growth DCF (EPS Growth)	10.22	10.34	
Constant-Growth DCF (DPS, EPS and BVPS)	9.12	9.10	
Sustainable-Growth DCF	8.44	8.50	
DCF Range (Minimum & Maximum):	**8.44**	**10.34**	**9.39**

CAPM Methodology	CAPM	Max	Midpoint
Capital Asset Pricing Model (Lg. Stock ERP, 30-yr T-Bond Rate)	11.44		
Capital Asset Pricing Model (Supply-Side ERM, 30-yr T-Bond Rate)	10.55		
Capital Asset Pricing Model (Kroll Normalized Rate)	8.20		
CAPM Range (Minimum & Maximum):	**8.20**	**11.44**	**9.82**

Summary			
DCF-Based ROE Average			9.28
	Min	**Max**	**Midpoint**
ROE Range	8.44	10.34	9.39
Recommended ROE (%)			**9.40**

Q. IN PAST CASES, HAVE YOU RELIED ON THE MINIMUM OF YOUR DCF RESULTS TO SET THE MINIMUM OF YOUR ROE RANGE?

A. No. In past proceedings, I have relied on the average of my DCF results to set the minimum of my ROE range because I did not believe the lowest results to be reasonable. In this case, however, I do not feel that it is necessary to truncate the lower bound of my ROE range given the circumstances specific to Pike and current financial market conditions.

Q. WHY IS YOUR ROE RECOMMENDATION OF 9.40% BASED ON A RANGE DERIVED FROM YOUR DCF METHODOLOGIES?

A. I place more emphasis on my DCF-derived results because it is widely used by both the finance community and public utility commissions across the country and yields more reliable results. It is a forward-looking model that directly incorporates investors' expectations of company dividend income through current market pricing signals, particularly in the case of utility stocks where stock valuations are telling a different story than the general market. The DCF also reflects recent developments in management decisions regarding key financials reflected in expected dividend and earnings growth.

The CAPM results, by contrast, are largely reliant on financial market outcomes complicated by monetary policy and investors' expectations of inflation and economic growth over the long run. Specifically, the estimated risk-free rate has a direct impact on the estimated ROE and is largely influenced by the analyst's assumptions. Moreover, the CAPM lacks a direct and immediate link from stock prices to the results. Although the beta coefficient in the CAPM reflects changes in the ROE, such information is delayed. However, I rely on my CAPM results as a reasonableness check.

Q. HOW DOES YOUR RECOMMENDATION COMPARE TO RECENTLY ALLOWED EQUITY RETURNS?

A. My recommended ROE of 9.40% is in line with current allowed ROEs issued by regulatory commissions across the country. S&P MI reports that the average allowed equity return for distribution-only electric utilities for 2024 was 9.53%, which is higher to the average for 2023 of 9.24%.[85] My recommended ROE of 9.40% is only 7 basis-points lower than the average allowed ROE for distribution-only electric utilities in 2024.

Q. HOW DOES PIKE'S ROE RECOMMENDATION COMPARE TO RECENTLY ALLOWED EQUITY RETURNS?

A. Pike's recommended ROE of 9.75% is 35 basis-points higher than the average allowed ROE for distribution-only electric utilities for 2024. Thus, if the Commission grants Pike's recommended ROE, it would be an outlier relative to the average allowed ROE for distribution-only electric utilities throughout the U.S.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to supplement my testimony as new information becomes available.

[85] S&P MI, "RRA Regulatory Focus - Major Energy Rate Case Decisions in the US – January-December 2024" (February 4, 2025), at 3.

DOCKET NO. R-2024-3052359
PIKE COUTY LIGHT & POWER – ELECTRIC RATE CASE
DIRECT TESTIMONY OF
MAUREEN L. RENO

APPENDIX A: CURRICULUM VITAE AND QUALIFICATIONS

Maureen L. Reno

Maureen Reno is a seasoned expert with 24 years of experience in the field of public utility regulation. After she completed her Ph.D. studies in Economics at the University of New Hampshire, Ms. Reno launched her career in public utility regulation as a utility analyst and program manager at the New Hampshire Public Utilities Commission, where she worked for the next 10 years. In this capacity, she provided expert testimony on rate of return (to include return on equity) in electricity, natural gas, and water utility rate cases. Ms. Reno also led the development and implementation of New Hampshire's Renewable Portfolio Standard program, helping both owners of distributed generation and load serving entities meet compliance requirements and maneuver the dynamic wholesale energy and renewable energy certificate markets. In addition, she managed New Hampshire's participation in the Regional Greenhouse Gas Initiative. Finally, Ms. Reno served as an expert witness on financial issues regarding the regulation of electric, natural gas, and water utilities, to include cost of capital and return on shareholder equity.

Subsequently, Ms. Reno served as a Senior Energy Economist with the Union of Concerned Scientists. In this capacity, she developed clean energy financing policies and advocated for electricity sector solutions to global warming.

Since 2012, Ms. Reno has served as an independent consultant, working with other small businesses to advise government and industry clients on diverse utility-related matters. In addition, she has served as an expert witness on rate design and rate of return (to include return on equity) in numerous cases. Her testimony has been presented to public utility commissions across the United States, to include the Regulatory Commission of Alaska, Arizona Corporation Commission, California Public Utilities Commission, Delaware Public Service Commission, Georgia Public Service Commission, Kansas Corporation Commission, Missouri Public Service Commission, New Hampshire Public Utilities Commission, New Mexico Public Regulation Commission, North Carolina Utilities Commission, Oklahoma Corporation Commission, South Carolina Public Service Commission, and Public Utility Commission of Texas. Ms. Reno's testimony has been consistently accepted by public utility commissions.

Ms. Reno stays abreast of the latest developments in utility regulatory law and policy through her research and professional activities. Given the complexity of Federal and state regulations that affect her clients, Ms. Reno dedicates significant time and energy to reviewing regulatory developments enacted by the U.S. Department of Energy, the Federal Energy Regulatory Commission (FERC), and the U.S. Environmental Protection Agency. For instance, Ms. Reno recently evaluated Maryland's RPS in light of FERC rulings on PJM's Capacity Auction to assess the financial viability of renewable energy projects within Maryland.

EDUCATION

- Completed all course work and exam requirements towards the Doctorate of Philosophy in Economics – University of New Hampshire, Durham.
  Fields of Specialization: Industrial Organization and Environmental Economics
- Master of Arts in Economics – University of New Hampshire, Durham, 1998
- Bachelor of Arts in Economics – University of Maine, Orono, 1996

PROFESSIONAL EXPERIENCE

- Independent Consultant and Principal, Reno Energy Consulting Services, LLC (2016-Present)
- Rates and Market Policy Director, New Hampshire Office of the Consumer Advocate (2021-2022)
- Independent Consultant (2012-2016)
- Senior Energy Economist, Union of Concerned Scientists (2011-2012)
- Analyst, Program Manager, Utility Analyst, and Economist, New Hampshire Public Utilities Commission (2001-2011)
- Survey Manager, New Hampshire Small Business Development Center (1999-2001)
- Adjunct Instructor, University of New Hampshire (1999-2001)

PROFESSIONAL WORK

As an independent consultant (as a prime contractor with Reno Energy Consulting Services, LLC and subcontractor under Exeter Associates, TAHOEconomics, and Nordee Enterprise LLC), Ms. Reno:

- Reviewed, analyzed, and prepared oral and written testimony in electric, natural gas, and water utility rate cases on topics that include rate design (revenue decoupling mechanisms); rate of return (including return on equity, capital structure, and accounting adjustments), and mergers and acquisitions.

- Worked with solar power installer to assess return on investment and payback period for investments in energy storage that included analyzing customer load profiles, utility tariffs, tax credits, and potential revenues from wholesale markets and state programs.

- Prepared report that included assessment of electricity options and projected revenues and costs for the Army & Air Force Exchange Service's West Coast Distribution Center, which included analyzing Pacific Gas & Electric Company's tariffs and potential revenues from wholesale markets for investments in solar power and energy storage.

As the Rates and Market Policy Director at the New Hampshire Office of the Consumer Advocate, Ms. Reno:

- Reviewed and analyzed utility filings and prepared written recommendations in two natural gas utility proceedings pertaining to a revenue decoupling adjustment mechanism and a renewable natural gas contract.

- Reviewed and analyzed utility filings and provided oral testimony in an electric utility's electric vehicle make-ready program and proposed tariff rates.

- Reviewed, analyzed and prepared oral and written recommendations for the Consumer Advocate on utility requests for changes in energy service rate charges (electric default service and cost of gas) and other surcharges reflected in utility company tariffs.

As an independent consultant for Exeter Associates Inc., Ms. Reno:

- Preparing the financial analysis and ratepayer impacts of a long-term contract requirement under Maryland's RPS for the Power Plant Research Program (PPRP) on behalf of the Maryland Department of Natural Resources.

  Evaluated utility proposals for deployment, cost-benefit analysis, and cost recovery of Maryland's Statewide Electric Vehicle Portfolio on behalf of the Maryland Energy Administration through the PPRP in Case No. 9478 In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio.

- Conducted research and drafted sections of regional energy market operations manuals for the US Department of Energy's Federal Energy Management Program. The reports focused on how federal facilities were pursuing renewable energy development under the different market constructs, such as by vertically integrated electric utilities, electric utilities with the PJM footprint, and electric utilities in California, and how those market constructs affected the prospects for future renewable energy development.

As an independent consultant for TAHOEconomics LLC, Ms. Reno:

- Provided written and oral testimony and legal briefs on behalf of the City of Clovis, New Mexico, in a water utility rate cases before the New Mexico Public Regulation Commission. Assessed EPCOR Water New Mexico Inc.'s weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.

As an independent consultant for Stephenson Strategic Communications, LLC, Ms. Reno:

- Provided consulting services to build support in New Hampshire for strong national climate and energy policies on behalf of a nationally recognized, non-profit environmental organization.

- Mobilized experts and leaders in New Hampshire to engage elected federal, state and local officials through targeted Senator visits, media interviews, public events, letters to the editor, and opinion and editorial articles.

- Communicated directly with targeted legislators and their staff to determine their positions on climate and clean air policies and address their concerns.

As an independent consultant for TrueLight Energy, LLC, Ms. Reno:

- Acted as director of regulatory affairs to expand upon current services to provide clients with guidance on how to navigate the dynamic deregulated electricity industry.

- Developed regulatory service product for clients, which includes ISO/utility tariff tracking and rate impact analysis, policy analysis, new market identification and participation in regulatory processes.

- Identified and originated new commercial opportunities in the U.S. to support principle product/service lines: retail supplier solutions; generation asset management; and sustainability management solutions for large energy users.

- Developed and implemented business development and business-to-business marketing strategies in coordination with senior management.

As a senior economist at the Union of Concerned Scientists, Ms. Reno:

- Promoted the development of clean energy technologies and policies in the electricity sector. Designed and evaluated energy policies at the state, regional, and national levels to maximize economic benefits and overcome market barriers to renewable energy.

- Evaluated and developed alternative financial policies to national and state renewable energy standards. Completed internal documents and research focusing on master limited partnerships and real estate investment trusts as possible sources of financing capital for renewable energy projects.

- Informed and enhanced coalition strategies by evaluating and developing appropriate responses to federal policy opportunities, including a low-carbon electricity standard, production tax credit, and other emerging opportunities.

- Evaluated the net benefits and opportunities for economic development in renewable energy manufacturing and the supply chain.

As an analyst and program manager at the New Hampshire Public Utilities Commission, Ms. Reno:

- Developed and managed New Hampshire's RPS Program.

- Developed internal protocols for managing New Hampshire's RPS program pursuant to PUC's RPS program rules (N.H. Code of Administrative Rules PUC 2500), including designing resource eligibility application forms.

- Verified electricity providers' compliance with New Hampshire's RPS program and processed applications for renewable energy source eligibility.

- Prepared and submitted annual RPS compliance reports, including program evaluation and policy analysis, to the State legislature on behalf of the PUC.

- Monitored and forecasted renewable energy certificate market trends in New England and New Hampshire to estimate available revenues supporting rebate programs.

- Maintained an RPS program website and renewable energy sources database.

- Participated in various regional working groups, including the RGGI Allowance and Offset Market Groups, and the GIS Regulators' Caucus to develop and maintain the NEPOOL GIS Operating Rules.

- Developed Greenhouse Gas Emissions Reduction Fund Cost Effectiveness Analysis model for request for proposal applicants.

As a utility analyst and economist at the New Hampshire Public Utilities Commission, Ms. Reno:

- Reviewed, analyzed and prepared oral and written recommendations in eight electric, natural gas and water utility rate cases in which she calculated each company's weighted average cost of capital and estimated the rate of return on equity using discounted cash flow, risk premium, and capital asset pricing models.

- Advised the PUC on utilities' debt financings, bond issuances, power plant retrofit, advanced/net metering, demand response, environmental disclosure, and incentives for in-state energy efficiency programs.

- Collaborated on behalf of the PUC with public and private entities to write New Hampshire's RPS law (HB 873), state participation in RGGI (HB 1434) and the PUC's RPS program rules (N.H. Code of Administrative Rules Puc 2500).

- Advised the Commissioners on the development of the RGGI carbon dioxide emission limits and the Allowance Auction Market.

- Prepared fiscal impact statements regarding proposed legislation and regulations in the State of New Hampshire using cost-benefit analysis.

As a Survey Manager for the New Hampshire Small Business Development Center, Ms. Reno:

- Designed and distributed a survey to collect data on the characteristics of New Hampshire manufacturers.

- Managed collection of survey data, designed a database for the data collected and oversaw data entry efforts.

- Analyzed the economic and behavioral factors that lead to the growth of New Hampshire manufacturing companies using multivariate regression, factor and cluster analysis of survey data.

As an Adjunct Instructor for the University of New Hampshire, Ms. Reno:

- Taught undergraduate courses in Principles of Macroeconomics and Microeconomics, including lectured on a daily basis, and developed lesson plans and teaching materials.
- Managed teaching assistant’s work correcting and grading testing materials and writing assignments.

UTILITY LITIGATION

State	Client	Citation/Utility	Industry	Topics
New Mexico	Bernalillo County (BC)	24-00089-UT/Public Service Co. of New Mexico	Electric	Cost of Capital and Return on Equity
South Carolina	U.S. Department of Defense (DoD)	2024-34-E/Dominion Energy South Carolina, Inc.	Electric	Cost of Capital and Return on Equity
New Mexico	BC	22-00058-UT/ Public Service Co. of New Mexico	Electric	Grid Modernization Cost-Benefit Analysis
Delaware	Public Service Commission Staff (DE PSC Staff)	23-0601/Artesian Water Company, Inc.	Water	Cost of Capital and Return on Equity
New Mexico	U.S. Department of Energy (DOE)	23-00255-UT/New Mexico Gas Company. Inc.	Natural Gas	Cost of Capital and Return on Equity
California	Small Business Utility Advocates	23-01-008/San Diego Gas & Electric Company	Electric	Rate Design & Cost of Service
Kansas	DoD	23-EKCE-775-RTS/Evergy Kansas Central, Inc. & Evergy Kansas Metro,	Electric	Cost of Capital and Return on Equity
Delaware	DE PSC Staff	22-0897/Delaware Power & Light	Electric	Cost of Capital and Return on Equity
Texas	DOE	54634/Southwestern Public Service Company	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
New Mexico	BC	22-00270-UT/ Public Service Co. of New Mexico	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
North Carolina	DoD	E-2, SUB 1300/ Duke Energy Progress, LLC	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
Georgia	DoD	44280/ Georgia Power Company	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk

Texas	DoD	53601/ Oncor Electric Delivery Company	Electric	Cost of Capital and Return on Equity
New Hampshire	Office of the Consumer Advocate (NH OCA)	DE 21-078/ Eversource	Electric	Electric Vehicle Make-Ready and Demand Charge Alternative
Alaska	DoD	U-21-070/U-21-071/ Golden Heart Utilities, Inc. and College Utilities Corporation	Water, Wastewater	Cost of Capital and Return on Equity
New Hampshire	NH OCA	DG 21-104/ Northern Utilities, Inc.	Natural Gas	Rate Design: Revenue Decoupling Adjustment Mechanism and Impacts on Risk
New Hampshire	NH OCA	DG 21-036/ Liberty Utilities	Natural Gas	Cost-Effectiveness of a Renewable NG Supply Agreement
Texas	DoD	52195/ El Paso Electric Company	Electric	Cost of Capital and Return on Equity
New Mexico	BC	20-00222-UT/ Public Service Co. of New Mexico	Electric	Mergers & Acquisitions: Benefits and Risks
New Mexico	BC	20-00121-UT/ Public Service Co. of New Mexico	Electric	Rate Design: Decoupling Mechanism
New Mexico	Public Regulation Commission Staff	19-00170-UT/ Southwestern Public Service Company	Electric	Cost of Capital and Return on Equity
Georgia	DoD	42516/ Georgia Power Company	Electric	Cost of Capital, Return on Equity, and Rate Design Impacts on Risk
Arizona	DoD	E-01933A-19-0028/ Tucson Electric Power Company	Electric	Cost of Capital and Return on Equity
New Mexico	City of Clovis, NM	18-00124-UT/ EPCOR Water New Mexico Inc.	Water	Cost of Capital and Return on Equity
Oklahoma	DoD	PUD 201700151/ Public Service Co. of Oklahoma	Electric	Cost of Capital and Return on Equity
Oklahoma	DoD	PUD 201500208/ Public Service Co. of Oklahoma	Electric	Cost of Capital, Return on Equity, and

				Rate Design Impacts on Risk
Texas	DOE	43695/ Southwestern Public Service Company	Electric	Cost of Capital and Return on Equity
Missouri	DOE	ER-2014-0370/ Kansas City Power & Light Co.	Electric	Cost of Capital and Return on Equity
Texas	DOE	41791/ Entergy Texas, Inc.	Electric	Cost of Capital and Return on Equity
New Hampshire	Public Utilities Commission (NH PUC)	DE 05-178/ Unitil Energy Systems, Inc.	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 04-177/ Public Service Co. of New Hampshire (generation assets)	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DW 04-056/ Pennichuck Water Works, Inc.	Water	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 03-200/ Public Service Co. of New Hampshire	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 03-166/ Public Service Co. of New Hampshire	Electric	Financial Incentives Associated with a Power Plant Retrofit from Coal to Biomass
New Hampshire	NH PUC	DE 01-247/ Concord Electric Co. and Exeter & Hampton Electric Co.	Electric	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DE 01-168/ Public Service Co. of New Hampshire	Electric	Refinancing of Long-term Debt, Short-term Debt Limit, and Utilization of Derivative Instruments
New Hampshire	NH PUC	DG 01-182/ Northern Utilities, Inc.	Natural Gas	Cost of Capital and Return on Equity
New Hampshire	NH PUC	DW 01-081/ Pennichuck Water Works, Inc.	Water	Cost of Capital and Return on Equity

UTILITY-RELATED MATTERS

State	Client	Description
New Jersey	Division of the Rate Counsel	Provided cost of capital and return on equity to client for settlement purposes in Jersey City Power & Light EnergizeNJ case EO-23110793.
California	Small Business Utility Advocates	Provided Comments on utility draft annual reports concerning California's RPS Rulemaking Case No. 18-07-003.
New Hampshire & Massachusetts	Nordee Enterprise LLC	Worked with solar power installer to assess return on investment and payback period for investments in energy storage that included analyzing customer load profiles, utility tariffs, tax credits, and potential revenues from wholesale markets and state programs.
New Hampshire	Office of the Consumer Advocate (OCA)	Negotiated Settlement terms in DE 21-119 Eversource Energy's Proposed Tariff Amendment to Residential Time-of-Day Rate
New Hampshire	OCA	Negotiated Settlement terms in DE 20-170 Electric Distribution Utilities' Electric Vehicle Time of Use Rates
New Hampshire	OCA	Evaluated utility proposal and ratepayer impacts of Liberty Utilities cost of gas proposal in DG 21-130 (EnergyNorth Natural Gas) and DG 21-132 (Liberty-Keene Division)
New Hampshire	OCA	Evaluated Liberty Utilities' Firm Transportation Agreement with Tennessee Gas Pipeline Company LLC in DG 21-008
Maryland	Department of Natural Resources (DNR)	Prepared the financial analysis and ratepayer impacts of a long-term contract requirement under Maryland's RPS. The report titled "Final Report Concerning the Maryland Renewable Portfolio Standard as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017" was publicly released in December 2019.
Maryland	Energy Administration (EA)	Evaluated utility proposals for deployment, cost-benefit analysis, and cost recovery of Maryland's Statewide Electric Vehicle Portfolio in Case No.

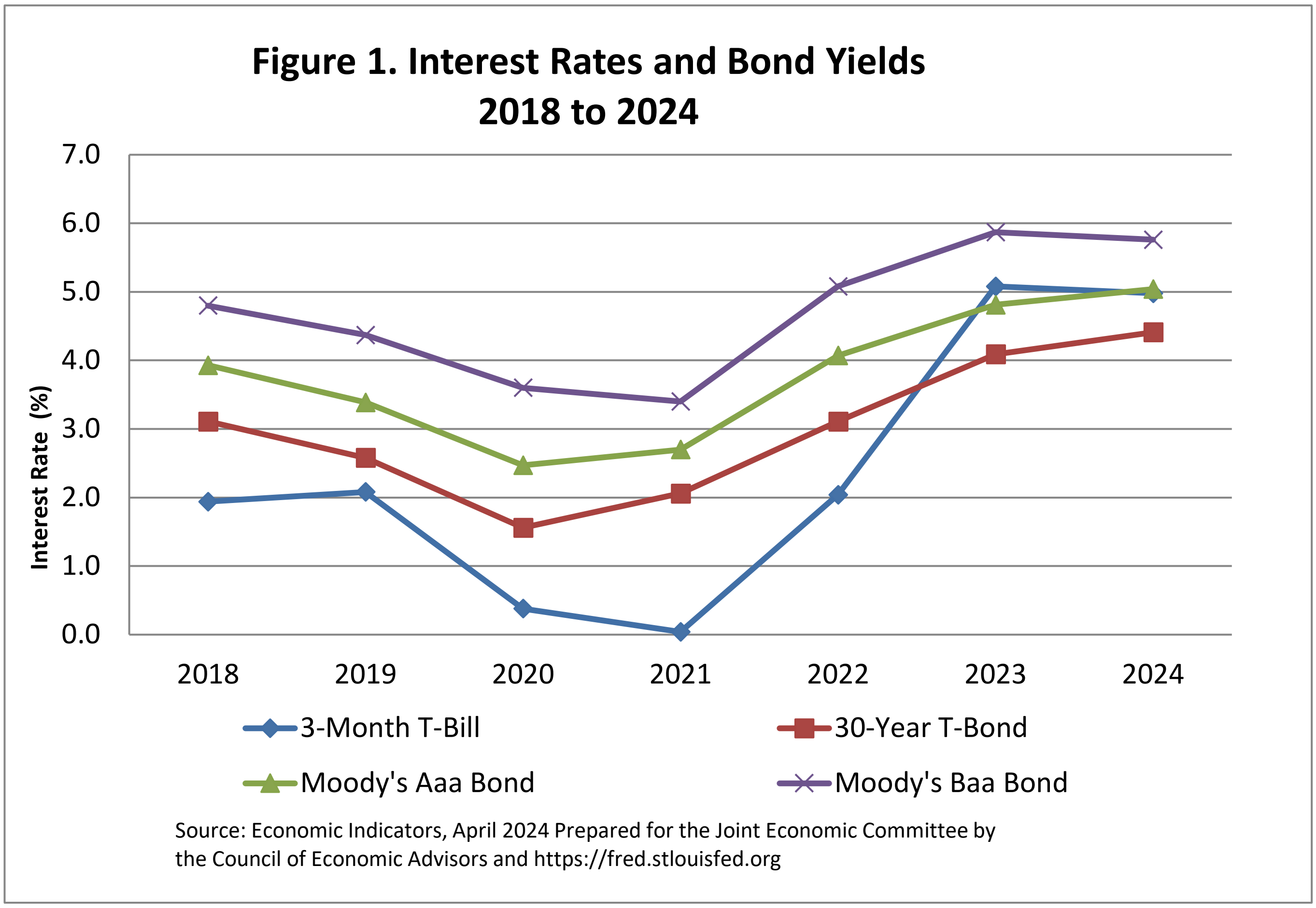
		9478 In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio.
Federal	US Department of Energy (DOE)	Conducted research and drafted sections of regional energy market operations manuals for the US Department of Energy's Federal Energy Management Program. The reports focused on how federal facilities were pursuing renewable energy development under different market constructs, such as by vertically integrated electric utilities, electric utilities with the PJM footprint, and electric utilities in California.
New Hampshire	Derry Town Council	Oversaw town energy committee's involvement in various energy cost saving projects or initiatives, such as installing a large solar array on the town's landfill, updating streetlights with LED fixtures, building a new transfer station that meets LEED certification, installing an electric vehicle charging station downtown, and hosting/managing resident participation in two Solar Up campaigns.
New Hampshire	Derry Town Council	Advised town council on establishing the Derry Net Zero Task Force and town goal of becoming Net Zero by 2025.
Massachusetts	Union of Concerned Scientists (UCS)	Evaluated and developed alternative financial policies to national and state renewable energy standards. Completed internal documents and research focusing on master limited partnerships and real estate investment trusts as possible sources of financing capital for renewable energy projects.
Massachusetts	UCS	Manufacturing Supply Chain Analysis of Wind Power Systems
New Hampshire	Public Utilities Commission (PUC)	Developed internal protocols for managing New Hampshire's RPS program pursuant to NHPUC's RPS program rules (N.H. Code of Administrative Rules PUC 2500), including designing resource eligibility application forms.

New Hampshire	PUC	Verified electricity providers' compliance with New Hampshire's RPS program and processed applications for renewable energy source eligibility.
New Hampshire	PUC	Prepared and submitted annual RPS compliance reports to the State legislature on behalf of the NHPUC.
New Hampshire	PUC	Developed Greenhouse Gas Emissions Reduction Fund Cost Effectiveness Analysis model for grant proposals.
New Hampshire	PUC	Collaborated on behalf of the NHPUC with public and private entities to write New Hampshire's RPS law (HB 873), law concerning state participation in Regional Greenhouse Gas Initiative (RGGI) (HB 1434) and the NHPUC's RPS program rules (N.H. Code of Administrative Rules Puc 2500).
New Hampshire	PUC	Advised the Commissioners on the development of the RGGI carbon dioxide emission limits and the RGGI Allowance Auction Market.
New Hampshire	PUC	Assisted researchers at the University of New Hampshire in estimating the net benefits of New Hampshire's RPS and its participation in RGGI for the state legislature.

Schedule 1 - Historical Economic Trends (Percent Change from Previous Period)							
	2018	2019	2020	2021	2022	2023	2024
Real GDP	3.0	2.6	-2.2	6.1	2.5	2.9	2.8
GDP Price Index	2.3	1.7	1.3	4.5	7.1	3.6	2.4
Consumer Price Index	2.4	1.8	1.2	4.7	8.0	4.1	2.9
Personal Consumption Expenditures	2.0	1.4	1.1	4.1	6.6	3.8	2.5
Core Personal Consumption Exp.	1.9	1.6	1.3	3.6	5.4	4.1	2.8
Unemployment Rate	3.9	3.7	8.1	5.3	3.6	3.6	4.0
Employment/Population Ratio	60.4	60.8	56.8	58.4	60.0	60.3	60.1
Labor Force Participation Rate	62.9	63.1	61.7	61.7	62.2	62.6	62.6

Schedule 2a - Interest Rates and Bond Yields (2018 to 2024)							
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
3-Month T-Bill	1.94	2.08	0.38	0.04	2.04	5.08	4.98
10-Year T-Bond	2.91	2.14	0.89	1.45	2.95	3.96	4.21
30-Year T-Bond	3.11	2.58	1.56	2.06	3.11	4.09	4.41
Moody's Aaa Bond	3.93	3.39	2.47	2.70	4.07	4.81	5.04
Moody's Baa Bond	4.80	4.37	3.60	3.40	5.08	5.87	5.76
Prime Interest Rate	4.91	5.28	3.54	3.25	4.86	8.20	8.31
Federal Funds Rate	1.83	2.16	0.37	0.08	1.69	5.03	5.14

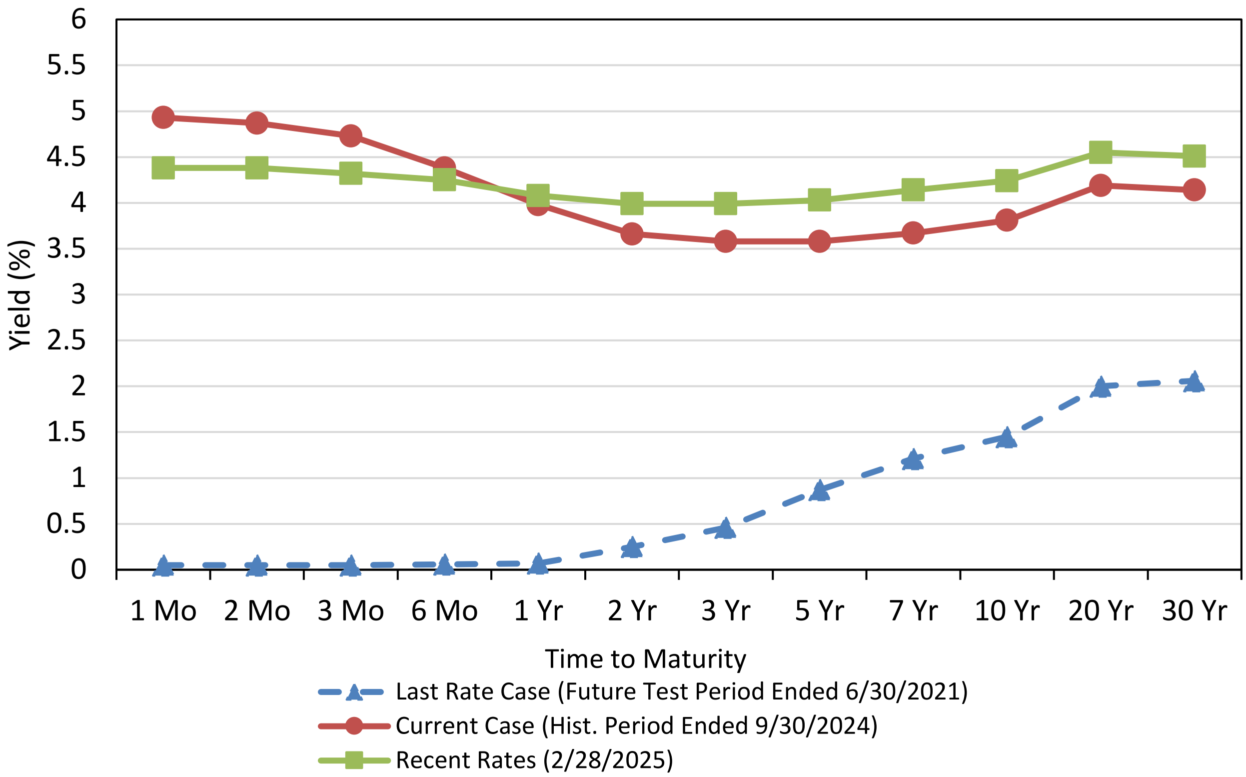
Source: Economic Indicators, January 2025, Prepared for the Joint Economic Committee by the Council of Economic Advisors at 30.
Moody's Baa-rated Corporate Bond Rates Source: https://fred.stlouisfed.org
Annual data reflects averages.



Schedule MLR-2b - Daily Yields on Treasury Securities

Time to Maturity	Last Rate Case (Future Test Period Ended 6/30/2021)	Current Case (Hist. Period Ended 9/30/2024)	Recent Rates (2/28/2025)
1 Mo	0.05	4.93	4.38
2 Mo	0.05	4.87	4.38
3 Mo	0.05	4.73	4.32
6 Mo	0.06	4.38	4.25
1 Yr	0.07	3.98	4.08
2 Yr	0.25	3.66	3.99
3 Yr	0.46	3.58	3.99
5 Yr	0.87	3.58	4.03
7 Yr	1.21	3.67	4.14
10 Yr	1.45	3.81	4.24
20 Yr	2	4.19	4.55
30 Yr	2.06	4.14	4.51

Figure 2. Treasury Security Yield Curve



Schedule MLR-2c - Daily Average TIPS Spread			
Date	Yield on 30-yr T-Bond	Yield on 30-yr T-Bond (Inflation Indexed)	30-Day TIPs Spread
12/2/2024	4.36	2.15	2.21
12/3/2024	4.4	2.17	2.23
12/4/2024	4.35	2.12	2.23
12/5/2024	4.33	2.13	2.2
12/6/2024	4.34	2.14	2.2
12/9/2024	4.39	2.18	2.21
12/10/2024	4.41	2.17	2.24
12/11/2024	4.48	2.22	2.26
12/12/2024	4.55	2.28	2.27
12/13/2024	4.61	2.33	2.28
12/16/2024	4.6	2.32	2.28
12/17/2024	4.59	2.33	2.26
12/18/2024	4.65	2.37	2.28
12/19/2024	4.74	2.47	2.27
12/20/2024	4.72	2.44	2.28
12/23/2024	4.78	2.47	2.31
12/24/2024	4.76	2.44	2.32
12/26/2024	4.76	2.43	2.33
12/27/2024	4.82	2.49	2.33
12/30/2024	4.77	2.47	2.3
12/31/2024	4.78	2.48	2.3
1/2/2025	4.79	2.48	2.31
1/3/2025	4.82	2.51	2.31
1/6/2025	4.85	2.53	2.32
1/7/2025	4.91	2.55	2.36
1/8/2025	4.91	2.55	2.36
1/9/2025	4.92	2.58	2.34
1/10/2025	4.96	2.6	2.36
1/13/2025	4.97	2.59	2.38
1/14/2025	4.98	2.61	2.37
1/15/2025	4.88	2.53	2.35
1/16/2025	4.84	2.51	2.33
1/17/2025	4.84	2.51	2.33
1/21/2025	4.8	2.48	2.32
1/22/2025	4.82	2.48	2.34
1/23/2025	4.87	2.5	2.37
1/24/2025	4.85	2.47	2.38
1/27/2025	4.76	2.4	2.36
1/28/2025	4.78	2.42	2.36
1/29/2025	4.79	2.42	2.37
1/30/2025	4.76	2.42	2.34

1/31/2025	4.83	2.46	2.37
2/3/2025	4.77	2.39	2.38
2/4/2025	4.75	2.37	2.38
2/5/2025	4.64	2.29	2.35
2/6/2025	4.65	2.3	2.35
2/7/2025	4.69	2.35	2.34
2/10/2025	4.71	2.36	2.35
2/11/2025	4.75	2.38	2.37
2/12/2025	4.83	2.46	2.37
2/13/2025	4.72	2.38	2.34
2/14/2025	4.69	2.36	2.33
2/18/2025	4.77	2.41	2.36
2/19/2025	4.76	2.4	2.36
2/20/2025	4.74	2.39	2.35
2/21/2025	4.67	2.35	2.32
2/24/2025	4.66	2.33	2.33
2/25/2025	4.55	2.27	2.28
2/26/2025	4.51	2.25	2.26
2/27/2025	4.56	2.3	2.26
2/28/2025	4.51	2.24	2.27
30-Day Average	**4.70**	**2.36**	**2.34**
90-Day Average	**4.71**	**2.39**	**2.32**

https://www.federalreserve.gov/releases/h15/

Schedule MLR-3 - Survey of Professional Forecasters (U.S. Quarterly and Annual Forecasts)

Percent (%) Growth at Annual Rates

	Quaterly					Year-Over-Year			
	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	2025	2026	2027	2028
Real Gross Domestic Product ("GDP")	2.50	2.10	2.00	2.10	2.20	2.40	2.20	1.80	2.00
Nominal GDP	5.00	4.70	4.70	4.50	4.50	4.80	4.50	N.A.	N.A.
GDP Price Index	2.50	2.50	2.40	2.60	2.70	2.30	2.50	N.A.	N.A.
Consumer Price Index ("CPI")	3.00	2.80	2.70	2.70	2.60	2.80	2.60	2.30	N.A.
CORE CPI	3.00	2.90	2.90	2.80	2.70	2.90	2.60	2.30	N.A.
Personal Consumption Expenditure ("PCE")	2.50	2.40	2.40	2.30	2.30	2.40	2.30	2.00	N.A.
CORE PCE	2.50	2.50	2.40	2.30	2.30	2.40	2.30	2.10	N.A.
Unemployment Rate	4.10	4.20	4.20	4.30	4.30	4.20	4.20	4.30	4.30
3-Month Treasury Bill	4.30	4.20	4.10	3.90	3.80	4.10	3.60	3.10	3.00
10-Year Treasury Bond	4.50	4.40	4.40	4.30	4.20	4.40	4.20	4.00	4.00
Moody's AAA Corp. Bond	5.30	5.24	5.16	5.11	5.10	5.20	5.20	N.A.	N.A.
Moody's BAA Corp. Bond	6.00	6.00	6.00	5.91	6.04	5.96	6.08	N.A.	N.A.

Source: Research Department, Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter 2025, at 9 and 11.

Note: The figures above represent medians of 40 forecasters.

Schedule MLR-4 - Sample Characteristics					
Proxy Group	**VL Beta (1.00 = Market)**	**S&P Credit Rating**	**Moody's Credit Rating**	**Common Equity Ratio (2025)**	**Long-Term Debt Ratio (2025)**
Alliant Energy Corp	0.95	A-	Baa2	44.50	55.50
Ameren Corp	0.90	BBB+	Baa1	47.00	52.50
American Electric Power Company Inc	0.85	BBB+	Baa2	42.00	58.00
Avista Corp	0.95	BBB	Baa2	49.50	50.50
CMS Energy Corp	0.90	BBB+	Baa2	34.50	64.50
Consolidated Edison Inc	0.80	A-	Baa1	49.00	51.00
Dominion Energy	0.90	BBB+	Baa2	43.00	54.50
DTE Energy Company	1.00	BBB+	Baa2	38.50	61.50
Duke Energy Corp New	0.90	BBB+	Baa2	37.50	62.00
Edison International	1.05	BBB	Baa2	28.50	64.00
Entergy Corp	1.00	BBB+	Baa2	36.50	63.50
Evergy Inc.	0.95	BBB+	Baa2	48.00	52.00
Eversource Energy	0.95	BBB+	Baa2	38.50	61.50
Exelon Corp	N/A	A-	Baa2	39.00	61.00
FirstEnergy Corp	0.90	BBB+	Baa3	34.00	66.00
IDACORP Inc	0.85	BBB	Baa2	51.00	49.00
MGE Energy Inc	0.80	NA	NA	63.50	36.50
NextEra Energy Inc	1.05	A-	Baa1	40.00	60.00
NorthWestern Corporation	1.00	BBB	Baa2	49.00	51.00
OGE Energy Corp	1.05	BBB+	Baa1	48.50	51.50
Otter Tail Corp	0.95	BBB	Baa2	58.50	41.50
Pinnacle West Capital Corp	0.95	BBB+	Baa2	46.00	54.00
Portland General Electric Company	0.95	BBB+	A3	44.00	56.00
PPL Corporation	1.10	A-	Baa1	49.00	51.00
Public Service Enterprise Group Inc	1.00	BBB+	Baa2	45.50	54.50
Southern Co	0.95	A-	Baa1	36.00	64.00
TXNM Energy Inc.	0.90	BBB	Baa3	32.00	67.50
Xcel Energy Inc	0.85	BBB+	Baa1	39.00	61.00
Sample Average	**0.94**			**43.29**	**56.27**
Sample Median	**0.95**			**43.50**	**55.75**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Credit Ratings as of March 3, 2025; reporterd by S&P Global Market Intelligence.

Schedule MLR-5a - Constant Growth DCF Results, EPS Growth Method (30-Stock Price)

Proxy Group	30-Day Stock Price Ave., P0	DPS (2025), D0	Current Div Yield, D0/P0	Expected Div Yield, D0/P0*(1+0.5g)	S&P Capital IQ Expected EPS Growth Next 5 yrs[1]	Zacks Expected EPS Growth Next 5 yrs[2]	VL Expected EPS Growth	Average Expected Earnings Growth Rate, g	1St DCF w/Earnings Growth, (D1/P0)+g
Alliant Energy Corp	60.97	2.04	3.35	3.45	6.73	6.40	6.00	6.38	9.83
Ameren Corp	97.19	2.85	2.93	3.03	6.82	6.70	6.50	6.67	9.70
American Electric Power Company Inc	101.92	3.80	3.73	3.85	6.59	6.00	6.50	6.36	10.21
Avista Corp	37.36	2.00	5.35	5.51	5.74	5.90	5.50	5.71	11.22
CMS Energy Corp	69.25	2.20	3.18	3.29	7.27	7.70	6.00	6.99	10.28
Consolidated Edison Inc	96.29	3.40	3.53	3.63	5.71	5.60	6.00	5.77	9.40
Dominion Energy	55.81	2.67	4.78	5.04	15.54	13.60	3.50	10.88	15.92
DTE Energy Company	126.16	4.41	3.50	3.61	7.59	7.60	4.50	6.56	10.17
Duke Energy Corp New	114.04	4.22	3.70	3.82	6.33	6.30	6.00	6.21	10.03
Edison International	52.05	3.36	6.46	6.71	8.25	8.50	6.50	7.75	14.46
Entergy Corp	83.48	2.43	2.91	3.01	8.88	9.50	3.00	7.13	10.14
Evergy Inc.	66.32	2.71	4.09	4.21	5.66	5.70	7.50	6.29	10.50
Eversource Energy	60.72	3.03	4.99	5.13	5.86	5.70	5.50	5.69	10.82
Exelon Corp	42.10	1.62	3.85	3.96	5.86	5.70	N/A	5.78	9.74
FirstEnergy Corp	40.63	1.80	4.43	4.57	6.70	6.90	5.50	6.37	10.94
IDACORP Inc	111.75	3.52	3.15	3.27	7.81	8.50	6.00	7.44	10.70
MGE Energy Inc	90.60	1.95	2.15	2.23	N/A	N/A	7.00	7.00	9.23
NextEra Energy Inc	69.96	2.26	3.23	3.36	7.65	7.80	8.50	7.98	11.34
NorthWestern Corporation	53.78	2.64	4.91	5.04	5.76	6.10	4.50	5.45	10.50
OGE Energy Corp	43.56	1.71	3.93	4.05	5.92	6.10	6.50	6.17	10.22
Otter Tail Corp	79.35	2.10	2.65	2.73	8.20	N/A	4.50	6.35	9.08
Pinnacle West Capital Corp	89.14	3.61	4.05	4.16	6.42	5.60	4.00	5.34	9.50
Portland General Electric Company	42.36	2.08	4.91	5.11	6.87	12.30	5.50	8.22	13.34
PPL Corporation	34.16	1.09	3.19	3.31	7.27	6.80	7.50	7.19	10.50
Public Service Enterprise Group Inc	83.68	2.56	3.06	3.16	6.58	7.20	6.00	6.59	9.75
Southern Co	86.03	2.96	3.44	3.55	6.62	6.80	6.50	6.64	10.19
TXNM Energy Inc.	50.09	1.65	3.29	3.37	6.00	3.00	4.00	4.33	7.70
Xcel Energy Inc	68.29	2.30	3.37	3.48	7.35	6.90	6.50	6.92	10.40
Sample Average	**71.68**	**2.61**	**3.79**	**3.92**	**7.11**	**7.11**	**5.76**	**6.65**	**10.56**
Sample Median									**10.22**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-5b - Constant Growth DCF Results, Expected EPS, DPS and BVPS Growth Method (30-Day Stock Price)									
Proxy Group	**30-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Current Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Average Expected Earnings Growth Rate, g[1]**	**VL Expected DPS Growth**	**VL Expected BVPS Growth**	**Average Expected Growth Rate (EPS, DPS, BVPS), g**	**1st DCF using EPS, DPS, BV Growth Rates, (D1/P0)+g**
Alliant Energy Corp	60.97	2.04	3.35	3.44	6.38	6.00	4.00	5.46	8.90
Ameren Corp	97.19	2.85	2.93	3.03	6.67	6.50	6.50	6.56	9.59
American Electric Power Company Inc	101.92	3.80	3.73	3.84	6.36	5.50	6.00	5.95	9.79
Avista Corp	37.36	2.00	5.35	5.46	5.71	4.00	2.00	3.90	9.36
CMS Energy Corp	69.25	2.20	3.18	3.27	6.99	5.00	5.00	5.66	8.93
Consolidated Edison Inc	96.29	3.40	3.53	3.61	5.77	4.00	4.00	4.59	8.20
Dominion Energy	55.81	2.67	4.78	4.90	10.88	0.50	3.00	4.79	9.69
DTE Energy Company	126.16	4.41	3.50	3.56	6.56	3.00	1.00	3.52	7.08
Duke Energy Corp New	114.04	4.22	3.70	3.78	6.21	3.50	3.00	4.24	8.02
Edison International	52.05	3.36	6.46	6.66	7.75	6.00	5.00	6.25	12.91
Entergy Corp	83.48	2.43	2.91	2.99	7.13	5.50	4.50	5.71	8.70
Evergy Inc.	66.32	2.71	4.09	4.20	6.29	7.00	3.50	5.60	9.80
Eversource Energy	60.72	3.03	4.99	5.12	5.69	6.00	3.50	5.06	10.18
Exelon Corp	42.10	1.62	3.85	3.96	5.78	N/A	N/A	5.78	9.74
FirstEnergy Corp	40.63	1.80	4.43	4.56	6.37	5.50	6.00	5.96	10.52
IDACORP Inc	111.75	3.52	3.15	3.24	7.44	5.50	4.50	5.81	9.05
MGE Energy Inc	90.60	1.95	2.15	2.22	7.00	6.50	5.50	6.33	8.55
NextEra Energy Inc	69.96	2.26	3.23	3.37	7.98	9.50	8.50	8.66	12.03
NorthWestern Corporation	53.78	2.64	4.91	4.99	5.45	1.50	3.00	3.32	8.31
OGE Energy Corp	43.56	1.71	3.93	4.02	6.17	3.00	5.50	4.89	8.91
Otter Tail Corp	79.35	2.10	2.65	2.74	6.35	7.00	8.00	7.12	9.86
Pinnacle West Capital Corp	89.14	3.61	4.05	4.13	5.34	1.50	4.50	3.78	7.91
Portland General Electric Company	42.36	2.08	4.91	5.06	8.22	5.50	4.00	5.91	10.96
PPL Corporation	34.16	1.09	3.19	3.24	7.19	-0.50	3.00	3.23	6.47
Public Service Enterprise Group Inc	83.68	2.56	3.06	3.15	6.59	6.00	5.50	6.03	9.18
Southern Co	86.03	2.96	3.44	3.52	6.64	3.50	3.50	4.55	8.07
TXNM Energy Inc.	50.09	1.65	3.29	3.37	4.33	5.50	4.50	4.78	8.15
Xcel Energy Inc	68.29	2.30	3.37	3.47	6.92	6.00	5.50	6.14	9.61
Sample Average	**71.68**	**2.61**	**3.79**	**3.89**	**6.65**	**4.76**	**4.54**	**5.34**	**9.23**
Sample Median									**9.12**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

1. Average Expected EPS Growth from Schedule MLR-5a.

Schedule MLR-5c - Constant Growth DCF Results, EPS Growth Method (90-Day Stock Price)									
Proxy Group	**90-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Current Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**S&P Capital IQ Expected EPS Growth Next 5 yrs[1]**	**Zacks Expected EPS Growth Next 5 yrs[2]**	**VL Expected EPS Growth**	**Average Expected Earnings Growth Rate, g**	**1St DCF w/Earnings Growth, (D1/P0)+g**
Alliant Energy Corp	60.00	2.04	3.40	3.51	6.73	6.40	6.00	6.38	9.89
Ameren Corp	93.02	2.85	3.06	3.17	6.82	6.70	6.50	6.67	9.84
American Electric Power Company Inc	97.12	3.80	3.91	4.04	6.59	6.00	6.50	6.36	10.40
Avista Corp	36.85	2.00	5.43	5.58	5.74	5.90	5.50	5.71	11.30
CMS Energy Corp	67.63	2.20	3.25	3.37	7.27	7.70	6.00	6.99	10.36
Consolidated Edison Inc	93.22	3.40	3.65	3.75	5.71	5.60	6.00	5.77	9.52
Dominion Energy	54.91	2.67	4.86	5.13	15.54	13.60	3.50	10.88	16.01
DTE Energy Company	122.75	4.41	3.59	3.71	7.59	7.60	4.50	6.56	10.27
Duke Energy Corp New	110.90	4.22	3.81	3.92	6.33	6.30	6.00	6.21	10.13
Edison International	66.20	3.36	5.08	5.27	8.25	8.50	6.50	7.75	13.02
Entergy Corp	79.20	2.43	3.07	3.18	8.88	9.50	3.00	7.13	10.30
Evergy Inc.	63.56	2.71	4.26	4.40	5.66	5.70	7.50	6.29	10.68
Eversource Energy	58.97	3.03	5.14	5.28	5.86	5.70	5.50	5.69	10.97
Exelon Corp	39.42	1.62	4.11	4.23	5.86	5.70	N/A	5.78	10.01
FirstEnergy Corp	40.19	1.80	4.48	4.62	6.70	6.90	5.50	6.37	10.99
IDACORP Inc	111.04	3.52	3.17	3.29	7.81	8.50	6.00	7.44	10.72
MGE Energy Inc	93.09	1.95	2.09	2.17	N/A	N/A	7.00	7.00	9.17
NextEra Energy Inc	71.27	2.26	3.17	3.30	7.65	7.80	8.50	7.98	11.28
NorthWestern Corporation	53.26	2.64	4.96	5.09	5.76	6.10	4.50	5.45	10.55
OGE Energy Corp	42.39	1.71	4.03	4.16	5.92	6.10	6.50	6.17	10.33
Otter Tail Corp	77.54	2.10	2.71	2.79	8.20	N/A	4.50	6.35	9.14
Pinnacle West Capital Corp	87.40	3.61	4.13	4.24	6.42	5.60	4.00	5.34	9.58
Portland General Electric Company	43.10	2.08	4.83	5.02	6.87	12.30	5.50	8.22	13.25
PPL Corporation	33.21	1.09	3.28	3.40	7.27	6.80	7.50	7.19	10.59
Public Service Enterprise Group Inc	85.46	2.56	3.00	3.09	6.58	7.20	6.00	6.59	9.69
Southern Co	84.27	2.96	3.51	3.63	6.62	6.80	6.50	6.64	10.27
TXNM Energy Inc.	48.90	1.65	3.37	3.45	6.00	3.00	4.00	4.33	7.78
Xcel Energy Inc	67.73	2.30	3.40	3.51	7.35	6.90	6.50	6.92	10.43
Sample Average	**70.81**	**2.61**	**3.81**	**3.94**	**7.11**	**7.11**	**5.76**	**6.65**	**10.59**
Sample Median									**10.34**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-5d - Constant Growth DCF Results, Expected EPS, DPS and BVPS Growth Method (90-Day Stock Price)									
Proxy Group	**90-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Current Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Average Expected Earnings Growth Rate, g[1]**	**VL Expected DPS Growth**	**VL Expected BVPS Growth**	**Average Expected Growth Rate (EPS, DPS, BVPS), g**	**1st DCF using EPS, DPS, BV Growth Rates, (D1/P0)+g**
Alliant Energy Corp	60.00	2.04	3.40	3.49	6.38	6.00	4.00	5.46	8.95
Ameren Corp	93.02	2.85	3.06	3.16	6.67	6.50	6.50	6.56	9.72
American Electric Power Company Inc	97.12	3.80	3.91	4.03	6.36	5.50	6.00	5.95	9.98
Avista Corp	36.85	2.00	5.43	5.53	5.71	4.00	2.00	3.90	9.44
CMS Energy Corp	67.63	2.20	3.25	3.34	6.99	5.00	5.00	5.66	9.01
Consolidated Edison Inc	93.22	3.40	3.65	3.73	5.77	4.00	4.00	4.59	8.32
Dominion Energy	54.91	2.67	4.86	4.98	10.88	0.50	3.00	4.79	9.77
DTE Energy Company	122.75	4.41	3.59	3.66	6.56	3.00	1.00	3.52	7.18
Duke Energy Corp New	110.90	4.22	3.81	3.89	6.21	3.50	3.00	4.24	8.12
Edison International	66.20	3.36	5.08	5.23	7.75	6.00	5.00	6.25	11.48
Entergy Corp	79.20	2.43	3.07	3.16	7.13	5.50	4.50	5.71	8.86
Evergy Inc.	63.56	2.71	4.26	4.38	6.29	7.00	3.50	5.60	9.98
Eversource Energy	58.97	3.03	5.14	5.27	5.69	6.00	3.50	5.06	10.33
Exelon Corp	39.42	1.62	4.11	4.23	5.78	N/A	N/A	5.78	10.01
FirstEnergy Corp	40.19	1.80	4.48	4.61	6.37	5.50	6.00	5.96	10.57
IDACORP Inc	111.04	3.52	3.17	3.26	7.44	5.50	4.50	5.81	9.07
MGE Energy Inc	93.09	1.95	2.09	2.16	7.00	6.50	5.50	6.33	8.49
NextEra Energy Inc	71.27	2.26	3.17	3.31	7.98	9.50	8.50	8.66	11.97
NorthWestern Corporation	53.26	2.64	4.96	5.04	5.45	1.50	3.00	3.32	8.36
OGE Energy Corp	42.39	1.71	4.03	4.13	6.17	3.00	5.50	4.89	9.02
Otter Tail Corp	77.54	2.10	2.71	2.80	6.35	7.00	8.00	7.12	9.92
Pinnacle West Capital Corp	87.40	3.61	4.13	4.21	5.34	1.50	4.50	3.78	7.99
Portland General Electric Company	43.10	2.08	4.83	4.97	8.22	5.50	4.00	5.91	10.88
PPL Corporation	33.21	1.09	3.28	3.34	7.19	-0.50	3.00	3.23	6.57
Public Service Enterprise Group Inc	85.46	2.56	3.00	3.09	6.59	6.00	5.50	6.03	9.12
Southern Co	84.27	2.96	3.51	3.59	6.64	3.50	3.50	4.55	8.14
TXNM Energy Inc.	48.90	1.65	3.37	3.45	4.33	5.50	4.50	4.78	8.23
Xcel Energy Inc	67.73	2.30	3.40	3.50	6.92	6.00	5.50	6.14	9.64
Sample Average	**70.81**	**2.61**	**3.81**	**3.91**	**6.65**	**4.76**	**4.54**	**5.34**	**9.25**
Sample Median									**9.10**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

1. Average Expected EPS Growth from Schedule MLR-5c.

Schedule MLR-6a - Sustainable Growth DCF (Internal Growth Component)

Proxy Group	Expected DPS (28-30)	Expected EPS (28-30)	BVPS (2025)	Expected BVPS (28-30)	Book Value Growth	Expected ROE = EPS/BVPS	Adjustment Factor	Adjusted ROE, r	Payout Ratio, DPS/EPS	Retention Rate, b	Internal Growth Rate, r*b
Alliant Energy Corp	2.43	4.25	28.85	31.90	0.020	13.32	1.01	13.46	0.57	0.43	5.76
Ameren Corp	3.57	6.50	45.95	52.65	0.028	12.35	1.01	12.51	0.55	0.45	5.64
American Electric Power Company Inc	4.31	7.50	52.35	60.90	0.031	12.32	1.02	12.50	0.57	0.43	5.32
Avista Corp	2.20	2.95	34.55	35.25	0.004	8.37	1.00	8.39	0.75	0.25	2.13
CMS Energy Corp	2.50	4.20	27.55	30.75	0.022	13.66	1.01	13.81	0.60	0.40	5.59
Consolidated Edison Inc	4.24	7.00	65.75	77.75	0.034	9.00	1.02	9.15	0.61	0.39	3.61
Dominion Energy	2.67	4.25	31.75	38.00	0.037	11.18	1.02	11.39	0.63	0.37	4.23
DTE Energy Company	5.15	9.60	58.40	63.10	0.016	15.21	1.01	15.33	0.54	0.46	7.11
Duke Energy Corp New	5.00	8.00	65.15	76.25	0.032	10.49	1.02	10.66	0.63	0.38	4.00
Edison International	4.00	6.75	40.35	48.60	0.038	13.89	1.02	14.15	0.59	0.41	5.76
Entergy Corp	3.00	4.20	36.50	43.45	0.035	9.67	1.02	9.83	0.71	0.29	2.81
Evergy Inc.	3.25	5.00	45.65	47.50	0.008	10.53	1.00	10.57	0.65	0.35	3.70
Eversource Energy	3.76	5.90	45.00	53.25	0.034	11.08	1.02	11.27	0.64	0.36	4.09
Exelon Corp	1.95	3.30	27.25	29.75	0.018	11.09	1.01	11.19	0.59	0.41	4.58
FirstEnergy Corp	2.30	3.70	19.80	25.50	0.052	14.51	1.03	14.88	0.62	0.38	5.63
IDACORP Inc	4.20	7.10	66.60	71.50	0.014	9.93	1.01	10.00	0.59	0.41	4.08
MGE Energy Inc	2.35	4.65	35.10	41.00	0.032	11.34	1.02	11.52	0.51	0.49	5.70
NextEra Energy Inc	3.22	5.10	26.05	36.00	0.067	14.17	1.03	14.62	0.63	0.37	5.39
NorthWestern Corporation	2.76	4.25	47.50	51.85	0.018	8.20	1.01	8.27	0.65	0.35	2.90
OGE Energy Corp	1.79	2.95	23.75	26.25	0.020	11.24	1.01	11.35	0.61	0.39	4.46
Otter Tail Corp	2.36	4.20	42.25	44.25	0.009	9.49	1.00	9.54	0.56	0.44	4.18
Pinnacle West Capital Corp	3.80	6.00	61.20	69.95	0.027	8.58	1.01	8.69	0.63	0.37	3.19
Portland General Electric Company	2.46	3.85	35.90	41.00	0.027	9.39	1.01	9.51	0.64	0.36	3.44
PPL Corporation	1.40	2.40	20.55	23.45	0.027	10.23	1.01	10.37	0.58	0.42	4.32
Public Service Enterprise Group Inc	3.24	5.25	34.10	42.50	0.045	12.35	1.02	12.62	0.62	0.38	4.83
Southern Co	3.10	5.50	31.75	32.25	0.003	17.05	1.00	17.08	0.56	0.44	7.45
TXNM Energy Inc.	1.94	3.35	28.80	33.50	0.031	10.00	1.02	10.15	0.58	0.42	4.27
Xcel Energy Inc	2.74	4.55	36.00	41.90	0.031	10.86	1.02	11.02	0.60	0.40	4.39
Sample Average	**3.06**	**5.08**	**39.80**	**45.36**	**0.03**	**11.41**	**1.01**	**11.57**	**0.61**	**0.39**	**4.59**
Sample Median											**4.35**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-6b - Sustainable Growth DCF (External Growth Component)

Proxy Group	30-Day Stock Price Ave., P0	BVPS (2025)	Market-to-Book Ratio, P0/BVPS	Comm Shares Outstanding (mil) 2024	Expected Comm Shares Outstanding in 5yrs	Growth in # Shares	Expected Growth in # of shares, s	Expected Profit of stock investment, v	External Growth, s*v
Alliant Energy Corp	60.97	28.85	2.11	256.69	257.00	0.02	0.05	0.53	0.03
Ameren Corp	97.19	45.95	2.12	266.93	285.00	1.32	2.79	0.53	1.47
American Electric Power Company Inc	101.92	52.35	1.95	532.90	550.00	0.63	1.23	0.49	0.60
Avista Corp	37.36	34.55	1.08	79.50	85.00	1.35	1.46	0.08	0.11
CMS Energy Corp	69.25	27.55	2.51	298.80	302.00	0.21	0.54	0.60	0.32
Consolidated Edison Inc	96.29	65.75	1.46	346.50	355.00	0.49	0.71	0.32	0.23
Dominion Energy	55.81	31.75	1.76	841.00	880.00	0.91	1.60	0.43	0.69
DTE Energy Company	126.16	58.40	2.16	207.17	206.00	-0.11	-0.24	0.54	-0.13
Duke Energy Corp New	114.04	65.15	1.75	772.50	777.00	0.12	0.20	0.43	0.09
Edison International	52.05	40.35	1.29	387.20	395.00	0.40	0.52	0.22	0.12
Entergy Corp	83.48	36.50	2.29	429.58	460.00	1.38	3.15	0.56	1.77
Evergy Inc.	66.32	45.65	1.45	230.00	230.00	0.00	0.00	0.31	0.00
Eversource Energy	60.72	45.00	1.35	367.00	372.00	0.27	0.37	0.26	0.09
Exelon Corp	42.10	27.25	1.55	1005.00	1005.00	0.00	0.00	0.35	0.00
FirstEnergy Corp	40.63	19.80	2.05	577.00	595.00	0.62	1.26	0.51	0.65
IDACORP Inc	111.75	66.60	1.68	53.50	56.00	0.92	1.54	0.40	0.62
MGE Energy Inc	90.60	35.10	2.58	36.50	36.50	0.00	0.00	0.61	0.00
NextEra Energy Inc	69.96	26.05	2.69	2058.00	2200.00	1.34	3.61	0.63	2.26
NorthWestern Corporation	53.78	47.50	1.13	61.50	64.00	0.80	0.91	0.12	0.11
OGE Energy Corp	43.56	23.75	1.83	200.90	200.20	-0.07	-0.13	0.45	-0.06
Otter Tail Corp	79.35	42.25	1.88	41.83	42.50	0.32	0.60	0.47	0.28
Pinnacle West Capital Corp	89.14	61.20	1.46	114.00	125.00	1.86	2.71	0.31	0.85
Portland General Electric Company	42.36	35.90	1.18	106.00	120.00	2.51	2.96	0.15	0.45
PPL Corporation	34.16	20.55	1.66	737.20	738.00	0.02	0.04	0.40	0.01
Public Service Enterprise Group Inc	83.68	34.10	2.45	499.00	505.00	0.24	0.59	0.59	0.35
Southern Co	86.03	31.75	2.71	1095.00	1095.00	0.00	0.00	0.63	0.00
TXNM Energy Inc.	50.09	28.80	1.74	91.00	95.00	0.86	1.50	0.43	0.64
Xcel Energy Inc	68.29	36.00	1.90	575.00	595.00	0.69	1.30	0.47	0.62
Sample Average	**71.68**	**39.80**	**1.85**	**438.11**	**450.94**	**0.61**	**1.04**	**0.42**	**0.43**
Sample Median									**0.25**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-6c - Sustainable Growth DCF (Results) (30-Day Stock Price)						
Proxy Group	**30-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Currnet Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Sustainable Growth Rate, rb+sv[1]**	**Sustainable Growth DCF, (D1/P0)+rb+sv**
Alliant Energy Corp	60.97	2.04	3.35	3.44	5.79	9.23
Ameren Corp	97.19	2.85	2.93	3.04	7.11	10.15
American Electric Power Company Inc	101.92	3.80	3.73	3.84	5.92	9.76
Avista Corp	37.36	2.00	5.35	5.41	2.24	7.66
CMS Energy Corp	69.25	2.20	3.18	3.27	5.91	9.18
Consolidated Edison Inc	96.29	3.40	3.53	3.60	3.84	7.43
Dominion Energy	55.81	2.67	4.78	4.90	4.92	9.82
DTE Energy Company	126.16	4.41	3.50	3.62	6.98	10.59
Duke Energy Corp New	114.04	4.22	3.70	3.78	4.08	7.86
Edison International	52.05	3.36	6.46	6.64	5.88	12.52
Entergy Corp	83.48	2.43	2.91	2.98	4.58	7.56
Evergy Inc.	66.32	2.71	4.09	4.16	3.70	7.86
Eversource Energy	60.72	3.03	4.99	5.09	4.18	9.28
Exelon Corp	42.10	1.62	3.85	3.94	4.58	8.51
FirstEnergy Corp	40.63	1.80	4.43	4.57	6.28	10.85
IDACORP Inc	111.75	3.52	3.15	3.22	4.71	7.93
MGE Energy Inc	90.60	1.95	2.15	2.21	5.70	7.91
NextEra Energy Inc	69.96	2.26	3.23	3.35	7.66	11.01
NorthWestern Corporation	53.78	2.64	4.91	4.98	3.00	7.99
OGE Energy Corp	43.56	1.71	3.93	4.01	4.41	8.42
Otter Tail Corp	79.35	2.10	2.65	2.71	4.46	7.16
Pinnacle West Capital Corp	89.14	3.61	4.05	4.13	4.04	8.17
Portland General Electric Company	42.36	2.08	4.91	5.01	3.89	8.89
PPL Corporation	34.16	1.09	3.19	3.26	4.34	7.59
Public Service Enterprise Group Inc	83.68	2.56	3.06	3.14	5.18	8.32
Southern Co	86.03	2.96	3.44	3.57	7.45	11.02
TXNM Energy Inc.	50.09	1.65	3.29	3.37	4.91	8.29
Xcel Energy Inc	68.29	2.30	3.37	3.45	5.00	8.45
Sample Average	**71.68**	**2.61**	**3.79**	**3.88**	**5.03**	**8.91**
Sample Median						**8.44**

1. See Schedule MLR-6a for internal growth component, rb and Schedule MLR-6b for external growth component, sv.

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-6d - Sustainable Growth DCF (Internal Growth Component)											
Proxy Group	**Expected DPS (28-30)**	**Expected EPS (28-30)**	**BVPS (2025)**	**Expected BVPS (28-30)**	**Book Value Growth**	**Expected ROE = EPS/BVPS**	**Adjustment Factor**	**Adjusted ROE, r**	**Payout Ratio, DPS/EPS**	**Retention Rate, b**	**Internal Growth Rate, r*b**
Alliant Energy Corp	2.43	4.25	28.85	31.90	0.020	13.32	1.01	13.46	0.57	0.43	5.76
Ameren Corp	3.57	6.50	45.95	52.65	0.028	12.35	1.01	12.51	0.55	0.45	5.64
American Electric Power Company In	4.31	7.50	52.35	60.90	0.031	12.32	1.02	12.50	0.57	0.43	5.32
Avista Corp	2.20	2.95	34.55	35.25	0.004	8.37	1.00	8.39	0.75	0.25	2.13
CMS Energy Corp	2.50	4.20	27.55	30.75	0.022	13.66	1.01	13.81	0.60	0.40	5.59
Consolidated Edison Inc	4.24	7.00	65.75	77.75	0.034	9.00	1.02	9.15	0.61	0.39	3.61
Dominion Energy	2.67	4.25	31.75	38.00	0.037	11.18	1.02	11.39	0.63	0.37	4.23
DTE Energy Company	5.15	9.60	58.40	63.10	0.016	15.21	1.01	15.33	0.54	0.46	7.11
Duke Energy Corp New	5.00	8.00	65.15	76.25	0.032	10.49	1.02	10.66	0.63	0.38	4.00
Edison International	4.00	6.75	40.35	48.60	0.038	13.89	1.02	14.15	0.59	0.41	5.76
Entergy Corp	3.00	4.20	36.50	43.45	0.035	9.67	1.02	9.83	0.71	0.29	2.81
Evergy Inc.	3.25	5.00	45.65	47.50	0.008	10.53	1.00	10.57	0.65	0.35	3.70
Eversource Energy	3.76	5.90	45.00	53.25	0.034	11.08	1.02	11.27	0.64	0.36	4.09
Exelon Corp	1.95	3.30	27.25	29.75	0.018	11.09	1.01	11.19	0.59	0.41	4.58
FirstEnergy Corp	2.30	3.70	19.80	25.50	0.052	14.51	1.03	14.88	0.62	0.38	5.63
IDACORP Inc	4.20	7.10	66.60	71.50	0.014	9.93	1.01	10.00	0.59	0.41	4.08
MGE Energy Inc	2.35	4.65	35.10	41.00	0.032	11.34	1.02	11.52	0.51	0.49	5.70
NextEra Energy Inc	3.22	5.10	26.05	36.00	0.067	14.17	1.03	14.62	0.63	0.37	5.39
NorthWestern Corporation	2.76	4.25	47.50	51.85	0.018	8.20	1.01	8.27	0.65	0.35	2.90
OGE Energy Corp	1.79	2.95	23.75	26.25	0.020	11.24	1.01	11.35	0.61	0.39	4.46
Otter Tail Corp	2.36	4.20	42.25	44.25	0.009	9.49	1.00	9.54	0.56	0.44	4.18
Pinnacle West Capital Corp	3.80	6.00	61.20	69.95	0.027	8.58	1.01	8.69	0.63	0.37	3.19
Portland General Electric Company	2.46	3.85	35.90	41.00	0.027	9.39	1.01	9.51	0.64	0.36	3.44
PPL Corporation	1.40	2.40	20.55	23.45	0.027	10.23	1.01	10.37	0.58	0.42	4.32
Public Service Enterprise Group Inc	3.24	5.25	34.10	42.50	0.045	12.35	1.02	12.62	0.62	0.38	4.83
Southern Co	3.10	5.50	31.75	32.25	0.003	17.05	1.00	17.08	0.56	0.44	7.45
TXNM Energy Inc.	1.94	3.35	28.80	33.50	0.031	10.00	1.02	10.15	0.58	0.42	4.27
Xcel Energy Inc	2.74	4.55	36.00	41.90	0.031	10.86	1.02	11.02	0.60	0.40	4.39
Sample Average	**3.06**	**5.08**	**39.80**	**45.36**	**0.03**	**11.41**	**1.01**	**11.57**	**0.61**	**0.39**	**4.59**
Sample Median											**4.35**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-6e - Sustainable Growth DCF - External Growth Component									
Proxy Group	**90-Day Stock Price Ave., P0**	**BVPS (2025)**	**Market-to-Book Ratio, P0/BVPS**	**Comm Shares Outstanding (mil) 2024**	**Expected Comm Shares Outstanding in 5yrs**	**Growth in # Shares**	**Expected Growth in # of shares, s**	**Expected Profit of stock investment, v**	**External Growth, s*v**
Alliant Energy Corp	60.00	28.85	2.08	256.69	257.00	0.02	0.05	0.52	0.03
Ameren Corp	93.02	45.95	2.02	266.93	285.00	1.32	2.67	0.51	1.35
American Electric Power Company Inc	97.12	52.35	1.86	532.90	550.00	0.63	1.18	0.46	0.54
Avista Corp	36.85	34.55	1.07	79.50	85.00	1.35	1.44	0.06	0.09
CMS Energy Corp	67.63	27.55	2.45	298.80	302.00	0.21	0.52	0.59	0.31
Consolidated Edison Inc	93.22	65.75	1.42	346.50	355.00	0.49	0.69	0.29	0.20
Dominion Energy	54.91	31.75	1.73	841.00	880.00	0.91	1.58	0.42	0.66
DTE Energy Company	122.75	58.40	2.10	207.17	206.00	-0.11	-0.24	0.52	-0.12
Duke Energy Corp New	110.90	65.15	1.70	772.50	777.00	0.12	0.20	0.41	0.08
Edison International	66.20	40.35	1.64	387.20	395.00	0.40	0.66	0.39	0.26
Entergy Corp	79.20	36.50	2.17	429.58	460.00	1.38	2.99	0.54	1.61
Evergy Inc.	63.56	45.65	1.39	230.00	230.00	0.00	0.00	0.28	0.00
Eversource Energy	58.97	45.00	1.31	367.00	372.00	0.27	0.36	0.24	0.08
Exelon Corp	39.42	27.25	1.45	1005.00	1005.00	0.00	0.00	0.31	0.00
FirstEnergy Corp	40.19	19.80	2.03	577.00	595.00	0.62	1.25	0.51	0.63
IDACORP Inc	111.04	66.60	1.67	53.50	56.00	0.92	1.53	0.40	0.61
MGE Energy Inc	93.09	35.10	2.65	36.50	36.50	0.00	0.00	0.62	0.00
NextEra Energy Inc	71.27	26.05	2.74	2058.00	2200.00	1.34	3.68	0.63	2.33
NorthWestern Corporation	53.26	47.50	1.12	61.50	64.00	0.80	0.90	0.11	0.10
OGE Energy Corp	42.39	23.75	1.78	200.90	200.20	-0.07	-0.12	0.44	-0.05
Otter Tail Corp	77.54	42.25	1.84	41.83	42.50	0.32	0.58	0.46	0.27
Pinnacle West Capital Corp	87.40	61.20	1.43	114.00	125.00	1.86	2.66	0.30	0.80
Portland General Electric Company	43.10	35.90	1.20	106.00	120.00	2.51	3.02	0.17	0.50
PPL Corporation	33.21	20.55	1.62	737.20	738.00	0.02	0.04	0.38	0.01
Public Service Enterprise Group Inc	85.46	34.10	2.51	499.00	505.00	0.24	0.60	0.60	0.36
Southern Co	84.27	31.75	2.65	1095.00	1095.00	0.00	0.00	0.62	0.00
TXNM Energy Inc.	48.90	28.80	1.70	91.00	95.00	0.86	1.47	0.41	0.60
Xcel Energy Inc	67.73	36.00	1.88	575.00	595.00	0.69	1.29	0.47	0.60
Sample Average	**70.81**	**39.80**	**1.83**	**438.11**	**450.94**	**0.61**	**1.03**	**0.42**	**0.42**
Sample Median									**0.26**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-6f - Sustainable Growth DCF (Results) (90-Day Stock Price)						
Proxy Group	**90-Day Stock Price Ave., P0**	**DPS (2025), D0**	**Current Div Yield, D0/P0**	**Expected Div Yield, D0/P0*(1+0.5g)**	**Sustainable Growth Rate, rb+sv[1]**	**Sustainable Growth DCF, (D1/P0)+rb+sv**
Alliant Energy Corp	60.00	2.04	3.40	3.50	5.79	9.29
Ameren Corp	93.02	2.85	3.06	3.17	6.99	10.16
American Electric Power Company In	97.12	3.80	3.91	4.03	5.86	9.89
Avista Corp	36.85	2.00	5.43	5.49	2.22	7.71
CMS Energy Corp	67.63	2.20	3.25	3.35	5.90	9.25
Consolidated Edison Inc	93.22	3.40	3.65	3.72	3.81	7.53
Dominion Energy	54.91	2.67	4.86	4.98	4.90	9.88
DTE Energy Company	122.75	4.41	3.59	3.72	6.98	10.70
Duke Energy Corp New	110.90	4.22	3.81	3.88	4.08	7.96
Edison International	66.20	3.36	5.08	5.23	6.02	11.25
Entergy Corp	79.20	2.43	3.07	3.14	4.42	7.56
Evergy Inc.	63.56	2.71	4.26	4.34	3.70	8.04
Eversource Energy	58.97	3.03	5.14	5.25	4.17	9.42
Exelon Corp	39.42	1.62	4.11	4.20	4.58	8.78
FirstEnergy Corp	40.19	1.80	4.48	4.62	6.26	10.88
IDACORP Inc	111.04	3.52	3.17	3.24	4.70	7.94
MGE Energy Inc	93.09	1.95	2.09	2.15	5.70	7.85
NextEra Energy Inc	71.27	2.26	3.17	3.29	7.72	11.02
NorthWestern Corporation	53.26	2.64	4.96	5.03	3.00	8.03
OGE Energy Corp	42.39	1.71	4.03	4.12	4.41	8.53
Otter Tail Corp	77.54	2.10	2.71	2.77	4.44	7.21
Pinnacle West Capital Corp	87.40	3.61	4.13	4.21	3.98	8.20
Portland General Electric Company	43.10	2.08	4.83	4.92	3.94	8.86
PPL Corporation	33.21	1.09	3.28	3.35	4.33	7.69
Public Service Enterprise Group Inc	85.46	2.56	3.00	3.07	5.19	8.27
Southern Co	84.27	2.96	3.51	3.64	7.45	11.10
TXNM Energy Inc.	48.90	1.65	3.37	3.46	4.88	8.33
Xcel Energy Inc	67.73	2.30	3.40	3.48	4.99	8.47
Sample Average	**70.81**	**2.61**	**3.81**	**3.91**	**5.01**	**8.92**
Sample Median						**8.50**

1. See Schedule MLR-6d for internal growth component, rb and Schedule MLR-6e for external growth component, sv.

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-7a - CAPM & ECAPM Assumptions	
(Historical Large Stock Return, 30-yr T-Bond)	**%**
Historical L-T Equity Risk Premium (1926-2023): Arithmetic Ave.[1]	7.17
Yield on T-Bond (Risk-Free Rate)	4.70
VL Sample Beta	0.94
VL Beta Adjusted Risk Premium	6.75
CAPM ROE	**11.44**

1. www.costofcapital.kroll.com.

2. Risk-free Rate based on 30-day average of yield on 30-Year Treasury bonds. See Schedule MLR-7b. Source: https://www.federalreserve.gov/releases/h15/

Schedule MLR-7b - CAPM & ECAPM Results (Historical Large Stock, 30-yr T-Bond)

Proxy Group	Risk-Free Rate	VL Beta (1.00 = Market)	Historical L-T Equity Risk Premium	CAPM ROE
Alliant Energy Corp	4.70	0.95	7.17	11.51
Ameren Corp	4.70	0.90	7.17	11.15
American Electric Power Company Inc	4.70	0.85	7.17	10.79
Avista Corp	4.70	0.95	7.17	11.51
CMS Energy Corp	4.70	0.90	7.17	11.15
Consolidated Edison Inc	4.70	0.80	7.17	10.43
Dominion Energy	4.70	0.90	7.17	11.15
DTE Energy Company	4.70	1.00	7.17	11.87
Duke Energy Corp New	4.70	0.90	7.17	11.15
Edison International	4.70	1.05	7.17	12.22
Entergy Corp	4.70	1.00	7.17	11.87
Evergy Inc.	4.70	0.95	7.17	11.51
Eversource Energy	4.70	0.95	7.17	11.51
Exelon Corp	4.70	N/A	7.17	
FirstEnergy Corp	4.70	0.90	7.17	11.15
IDACORP Inc	4.70	0.85	7.17	10.79
MGE Energy Inc	4.70	0.80	7.17	10.43
NextEra Energy Inc	4.70	1.05	7.17	12.22
NorthWestern Corporation	4.70	1.00	7.17	11.87
OGE Energy Corp	4.70	1.05	7.17	12.22
Otter Tail Corp	4.70	0.95	7.17	11.51
Pinnacle West Capital Corp	4.70	0.95	7.17	11.51
Portland General Electric Company	4.70	0.95	7.17	11.51
PPL Corporation	4.70	1.10	7.17	12.58
Public Service Enterprise Group Inc	4.70	1.00	7.17	11.87
Southern Co	4.70	0.95	7.17	11.51
TXNM Energy Inc.	4.70	0.90	7.17	11.15
Xcel Energy Inc	4.70	0.85	7.17	10.79
Sample Average	**4.70**	**0.94**	**7.17**	**11.44**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-7c - CAPM & ECAPM Assumptions	
(Supply-Side ERP, 30-yr T-Bond)	**%**
Supply-Side Equity Risk Premium (1926-2023): Arithmetic Ave.[1]	6.22
Yield on T-Bond (Risk-Free Rate)	4.70
VL Sample Beta	0.94
VL Beta Adjusted Risk Premium	5.85
CAPM ROE	**10.55**

1. www.costofcapital.kroll.com.
2. Risk-free Rate based on 30-day average of yield on 30-Year Treasury bonds. See Schedule MLR-7d. Source: https://www.federalreserve.gov/releases/h15/

Schedule MLR-7d - CAPM & ECAPM Results (Supply-Side Equity ERP, 30-yr T-Bond)

Proxy Group	Risk-Free Rate	VL Beta (1.00 = Market)	Supply-Side Risk Premium	CAPM ROE
Alliant Energy Corp	4.70	0.95	6.22	10.60
Ameren Corp	4.70	0.90	6.22	10.29
American Electric Power Company Inc	4.70	0.85	6.22	9.98
Avista Corp	4.70	0.95	6.22	10.60
CMS Energy Corp	4.70	0.90	6.22	10.29
Consolidated Edison Inc	4.70	0.80	6.22	9.67
Dominion Energy	4.70	0.90	6.22	10.29
DTE Energy Company	4.70	1.00	6.22	10.92
Duke Energy Corp New	4.70	0.90	6.22	10.29
Edison International	4.70	1.05	6.22	11.23
Entergy Corp	4.70	1.00	6.22	10.92
Evergy Inc.	4.70	0.95	6.22	10.60
Eversource Energy	4.70	0.95	6.22	10.60
Exelon Corp	4.70	N/A	6.22	
FirstEnergy Corp	4.70	0.90	6.22	10.29
IDACORP Inc	4.70	0.85	6.22	9.98
MGE Energy Inc	4.70	0.80	6.22	9.67
NextEra Energy Inc	4.70	1.05	6.22	11.23
NorthWestern Corporation	4.70	1.00	6.22	10.92
OGE Energy Corp	4.70	1.05	6.22	11.23
Otter Tail Corp	4.70	0.95	6.22	10.60
Pinnacle West Capital Corp	4.70	0.95	6.22	10.60
Portland General Electric Company	4.70	0.95	6.22	10.60
PPL Corporation	4.70	1.10	6.22	11.54
Public Service Enterprise Group Inc	4.70	1.00	6.22	10.92
Southern Co	4.70	0.95	6.22	10.60
TXNM Energy Inc.	4.70	0.90	6.22	10.29
Xcel Energy Inc	4.70	0.85	6.22	9.98
Sample Average	**4.70**	**0.94**	**6.22**	**10.55**

Source: Value Line Investment Survey, Issue 11 (Electric Utility West), January 17, 2025; Issue 5 (Electric Utility Central), March 7, 2025; and Issue 1 (Electric Utility East), February 7, 2025.

Schedule MLR-7e - CAPM & ECAPM Assumptions (D&P Normalized RF Rate)	%
D&P Recommended US ERP[1]	5.00
D&P Normalized Risk-Free Rate[1]	3.50
VL Sample Beta	0.94
VL Beta Adjusted Risk Premium	4.70
CAPM ROE	**8.20**

1. Kroll, Kroll Lowers Its Recommended U.S. Equity Risk Premium to 5.0%, Effective June 5, 2024.

Schedule MLR-7f - CAPM & ECAPM Results (D&P Normalized RF Rate)

Proxy Group	Normalized Risk-Free Rate[1]	VL Beta (1.00 = Market)	Recommended Market Risk Premium[1]	CAPM ROE
Alliant Energy Corp	3.50	0.95	5.00	8.25
Ameren Corp	3.50	0.90	5.00	8.00
American Electric Power Company Inc	3.50	0.85	5.00	7.75
Avista Corp	3.50	0.95	5.00	8.25
CMS Energy Corp	3.50	0.90	5.00	8.00
Consolidated Edison Inc	3.50	0.80	5.00	7.50
Dominion Energy	3.50	0.90	5.00	8.00
DTE Energy Company	3.50	1.00	5.00	8.50
Duke Energy Corp New	3.50	0.90	5.00	8.00
Edison International	3.50	1.05	5.00	8.75
Entergy Corp	3.50	1.00	5.00	8.50
Evergy Inc.	3.50	0.95	5.00	8.25
Eversource Energy	3.50	0.95	5.00	8.25
Exelon Corp	3.50	N/A	5.00	
FirstEnergy Corp	3.50	0.90	5.00	8.00
IDACORP Inc	3.50	0.85	5.00	7.75
MGE Energy Inc	3.50	0.80	5.00	7.50
NextEra Energy Inc	3.50	1.05	5.00	8.75
NorthWestern Corporation	3.50	1.00	5.00	8.50
OGE Energy Corp	3.50	1.05	5.00	8.75
Otter Tail Corp	3.50	0.95	5.00	8.25
Pinnacle West Capital Corp	3.50	0.95	5.00	8.25
Portland General Electric Company	3.50	0.95	5.00	8.25
PPL Corporation	3.50	1.10	5.00	9.00
Public Service Enterprise Group Inc	3.50	1.00	5.00	8.50
Southern Co	3.50	0.95	5.00	8.25
TXNM Energy Inc.	3.50	0.90	5.00	8.00
Xcel Energy Inc	3.50	0.85	5.00	7.75
Sample Average	**3.50**	**0.94**	**5.00**	**8.20**

2025; and Issue 1 (Electric Utility East), February 7, 2025.

1. Kroll, Kroll Lowers Its Recommendations and Potential Upcoming Changes - February 8, 2024 Update.

Schedule MLR-8a: Electric rate cases for CY 2024

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025

available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identificatio n	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
DC	Potomac Elec	FC-1176	Electric	4/13/2023	186,488	7.79	10.50	50.50	3,391,705	p	123,351	7.29	9.50	50.50	12/31/2026	3,302,877	Average	19.73	Distribution	Fully Litigated	Yes	No
DE	Delmarva Pov	D-22-0897	Electric	12/15/2022	53,744	7.42	10.50	50.50	1,081,304	4/18/2024	42,250	6.97	9.60	50.50	6/30/2023	NA		16.33	Distribution	Settled	No	Yes
MA	Fitchburg Gas	DPU 23-80	Electric	8/17/2023	5,142	8.04	10.50	52.26	84,907	6/28/2024	4,849	7.46	9.40	52.26	12/31/2022	84,754	Year-end	10.53	Distribution	Fully Litigated	Yes	No
MA	Massachusett	DPU 23-150	Electric	11/16/2023	118,300	7.70	10.50	52.83	3,160,000	9/30/2024	90,157	7.09	9.35	52.83	3/31/2023	3,126,537	Year-end	10.63	Distribution	Fully Litigated	Yes	No
MD	Potomac Elec	C-9702	Electric	5/16/2023	187,912	7.81	10.50	50.50	2,969,437	6/10/2024	44,629	7.13	9.50	50.50	3/30/2024	2,408,076	Average	13.03	Distribution	Fully Litigated	No	No
NJ	Jersey Centra	D-ER2303014	Electric	3/16/2023	192,250	7.60	10.40	51.90	3,049,777	2/14/2024	85,000	7.18	9.60	51.90	6/30/2023	2,960,587	Year-end	11.17	Distribution	Settled	No	No
NJ	Public Service	D-ER2312092	Electric	12/29/2023	560,915	7.54	10.40	55.50	9,642,298	10/9/2024	440,500	7.07	9.60	55.00	5/31/2024	9,300,000	Year-end	9.50	Distribution	Settled	No	No
NY	Central Hudsc	C-23-E-0418	Electric	7/31/2023	128,708	7.15	9.80	50.00	1,807,392	7/18/2024	74,418	6.92	9.50	48.00	6/30/2025	1,787,977	Average	11.77	Distribution	Fully Litigated	No	No
TX	AEP Texas In	D-56165	Electric	2/29/2024	100,387	7.18	10.60	45.00	4,248,453	10/3/2024	45,499	6.66	9.76	42.50	9/30/2023	4,273,499	Year-end	7.23	Distribution	Settled	No	No

Return on Rate Base (%)	
Mean	7.09
Standard E	0.08
Median	7.09
Mode	#N/A
Standard D	0.23
Sample Vai	0.05
Kurtosis	0.92
Skewness	(0.29)
Range	0.80
Minimum	6.66
Maximum	7.46
Sum	63.77
Count	9.00

Schedule MLR-8b: Electric rate cases for CY 2023

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025

available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
CT	The United Illu	D-22-08-08	Electric	9/9/2022	130,641	7.47	10.20	52.00	1,539,098	p	22,957	6.48	8.63	50.00	12/31/2023	1,105,196	Average	11.67	Distribution	Fully Litigated	No	No
IL	Commonweal	D-23-0055	Electric	1/17/2023	1,487,444	7.65	10.65	51.19	18,330,797	12/14/2023	1,053,522	6.71	8.91	50.00	12/31/2027	17,330,861	Average	11.03	Distribution	Fully Litigated	Yes	No
IL	Ameren Illinois	D-23-0082	Electric	1/20/2023	465,064	7.76	10.50	54.03	5,193,859	12/14/2023	309,355	6.59	8.72	50.00	12/31/2027	4,803,776	Average	10.93	Distribution	Fully Litigated	Yes	No
MD	Baltimore Gas	C-9692 (EL)	Electric	2/17/2023	313,893	7.56	10.40	52.00	5,593,441	12/14/2023	179,085	6.77	9.50	52.00	12/23/2026	5,197,916	Average	10.00	Distribution	Fully Litigated	Yes	No
MD	The Potomac	C-9695	Electric	3/22/2023	50,389	7.54	10.60	53.53	718,507	10/18/2023	28,746	6.92	9.50	53.00	12/31/2022	680,418	Average	7.00	Distribution	Fully Litigated	No	No
ME	Central Maine	D-2022-0015	Electric	8/11/2022	43,530	7.14	10.20	50.00	1,200,978	6/6/2023	67,000	6.74	9.35	50.00		NA		9.97	Distribution	Settled	Yes	No
ME	Versant Powe	D-2022-0025	Electric	10/3/2022	33,133	6.59	9.35	49.00	525,863	5/31/2023	30,358	6.59	9.35	49.00	12/31/2021	526,912	Average	8.00	Distribution	Settled	Yes	No
NJ	Atlantic City E	D-ER2302009	Electric	2/15/2023	91,990	7.13	10.50	50.20	2,243,893	11/17/2023	45,000	6.58	9.60	50.20	6/30/2023	2,118,727	Year-end	9.17	Distribution	Settled	Yes	No
NY	Consolidated	C-22-E-0064	Electric	1/28/2022	1,037,788	7.14	10.00	50.00	26,408,343	7/20/2023	442,306	6.75	9.25	48.00	12/31/2023	26,094,576	Average	17.93	Distribution	Settled	Yes	No
NY	New York Sta	C-22-E-0317	Electric	5/26/2022	274,445	6.95	10.20	50.00	3,926,456	10/12/2023	137,274	6.40	9.20	48.00	4/30/2024	3,747,889	Average	16.80	Distribution	Settled	Yes	No
NY	Rochester Ga	C-22-E-0319	Electric	5/26/2022	93,364	7.24	10.20	50.00	2,172,276	10/12/2023	50,965	6.67	9.20	48.00	4/30/2024	2,202,482	Average	16.80	Distribution	Settled	Yes	No
TX	Oncor Electric	D-53601	Electric	5/13/2022	250,691	7.05	10.30	45.00	18,815,928	3/9/2023	100,536	6.65	9.70	42.50	12/31/2021	18,618,610	Year-end	10.00	Distribution	Fully Litigated	No	No

Return on Rate Base (%)	
Mean	6.65
Standard E	0.04
Median	6.66
Mode	6.59
Standard D	0.14
Sample Var	0.02
Kurtosis	0.38
Skewness	(0.02)
Range	0.52
Minimum	6.40
Maximum	6.92
Sum	79.85
Count	12.00

Schedule MLR-8c: Electric rate cases for CY 2015-2025
where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025
available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
CT	The United Illu	D-16-06-04	Electric	7/1/2016	98,252	7.58	9.92	52.00	1,032,639	p	57,400	7.08	9.10	50.00	12/31/2015	1,014,144	Average	5.53	Distribution	Fully Litigated	Yes	No
CT	The Connectic	D-17-10-46	Electric	11/22/2017	336,989	7.70	10.50	53.45	3,899,733	4/18/2018	124,661	7.09	9.25	53.00	12/31/2016	3,861,111	Average	4.90	Distribution	Settled	Yes	No
CT	The United Illu	D-22-08-08	Electric	9/9/2022	130,641	7.47	10.20	52.00	1,539,098	8/25/2023	22,957	6.48	8.63	50.00	12/31/2023	1,105,196	Average	11.67	Distribution	Fully Litigated	No	No
DC	Potomac Elec	FC-1139	Electric	6/30/2016	77,494	8.00	10.60	49.14	1,714,834	7/24/2017	36,888	7.46	9.50	49.14	3/31/2016	1,627,944	Average	12.97	Distribution	Fully Litigated	No	No
DC	Potomac Elec	FC-1150	Electric	12/19/2017	65,679	7.74	10.10	50.28	1,872,430	8/8/2018	-24,100	7.45	9.53	50.44	12/31/2017	NA		7.73	Distribution	Settled	No	No
DC	Potomac Elec	FC-1156	Electric	5/30/2019	135,867	7.39	9.70	50.68	2,597,686	6/4/2021	108,600	7.17	9.28	50.68	12/31/2022	2,472,300	Average	24.53	Distribution	Fully Litigated	Yes	No
DC	Potomac Elec	FC-1176	Electric	4/13/2023	186,488	7.79	10.50	50.50	3,391,705	11/25/2024	123,351	7.29	9.50	50.50	12/31/2026	3,302,877	Average	19.73	Distribution	Fully Litigated	Yes	No
DE	Delmarva Pov	D-17-0977	Electric	8/17/2017	10,863	6.98	10.10	50.52	810,637	8/21/2018	-6,850	6.78	9.70	50.52	12/31/2017	NA		12.30	Distribution	Settled	No	Yes
DE	Delmarva Pov	D-20-0149	Electric	3/6/2020	26,300	7.15	10.30	50.37	910,231	8/5/2021	16,730	6.80	9.60	NA	3/31/2021	899,985	Average	17.23	Distribution	Fully Litigated	No	Yes
DE	Delmarva Pov	D-22-0897	Electric	12/15/2022	53,744	7.42	10.50	50.50	1,081,304	4/18/2024	42,250	6.97	9.60	50.50	6/30/2023	NA		16.33	Distribution	Settled	No	Yes
IL	Commonweal	D-15-0287	Electric	4/15/2015	-53,829	7.05	9.14	46.25	8,277,117	12/9/2015	-65,463	7.05	9.14	46.25	12/31/2014	8,276,940	Year-end	7.93	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-15-0305	Electric	4/24/2015	98,484	7.65	9.14	50.00	2,489,879	12/9/2015	95,089	7.65	9.14	50.00	12/31/2014	2,480,480	Year-end	7.63	Distribution	Fully Litigated	No	No
IL	Commonweal	D-16-0259	Electric	4/13/2016	135,727	6.71	8.64	45.62	8,831,123	12/6/2016	113,347	6.71	8.64	45.62	12/31/2015	8,826,618	Year-end	7.90	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-16-0262	Electric	4/15/2016	-8,694	7.28	8.64	50.00	2,556,575	12/6/2016	-8,811	7.28	8.64	50.00	12/31/2015	2,555,714	Year-end	7.83	Distribution	Fully Litigated	No	No
IL	Commonweal	D-17-0196	Electric	4/13/2017	99,176	6.47	8.40	45.89	9,661,978	12/6/2017	99,179	6.47	8.40	45.89	12/31/2016	9,661,978	Year-end	7.90	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-17-0197	Electric	4/13/2017	-16,427	7.04	8.40	50.00	2,738,545	12/6/2017	-16,427	7.04	8.40	50.00	12/31/2016	2,738,545	Year-end	7.90	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-18-0807	Electric	4/16/2018	73,695	6.99	8.69	50.00	2,951,878	11/1/2018	73,695	6.99	8.69	50.00	12/31/2017	2,951,879	Year-end	6.63	Distribution	Fully Litigated	No	No
IL	Commonweal	D-18-0808	Electric	4/16/2018	-26,104	6.52	8.69	47.11	10,675,237	12/4/2018	-26,104	6.52	8.69	47.11	12/31/2017	10,675,257	Year-end	7.73	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-19-0436	Electric	4/18/2019	-2,951	6.71	8.91	50.00	3,180,740	12/16/2019	-2,967	6.71	8.91	50.00	12/31/2018	3,180,739	Year-end	8.07	Distribution	Fully Litigated	No	No
IL	Commonweal	D-19-0387	Electric	4/8/2019	-2,739	6.51	8.91	47.97	11,355,130	12/4/2019	-3,114	6.51	8.91	47.97	12/31/2018	11,355,140	Year-end	8.00	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-20-0381	Electric	4/14/2020	-31,479	6.39	8.38	50.00	3,422,034	12/9/2020	-35,049	6.39	8.38	50.00	12/31/2019	3,413,085	Year-end	7.97	Distribution	Fully Litigated	No	No
IL	Commonweal	D-20-0393	Electric	4/16/2020	-13,402	6.28	8.38	48.16	12,050,339	12/9/2020	-13,786	6.28	8.38	48.16	12/31/2019	12,048,960	Year-end	7.90	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-21-0365	Electric	4/15/2021	44,023	5.78	7.36	51.00	3,686,239	12/13/2021	42,843	5.78	7.36	51.00	12/31/2020	3,676,453	Year-end	8.07	Distribution	Fully Litigated	No	No
IL	Commonweal	D-21-0367	Electric	4/16/2021	31,941	5.72	7.36	48.70	13,035,495	12/1/2021	31,939	5.72	7.36	48.70	12/31/2020	13,035,493	Year-end	7.63	Distribution	Fully Litigated	No	No
IL	Ameren Illinoi	D-22-0297	Electric	4/14/2022	85,916	6.06	7.85	53.99	3,891,160	12/1/2022	63,121	5.90	7.85	50.00	12/31/2021	3,890,341	Year-end	7.70	Distribution	Fully Litigated	No	No
IL	Commonweal	D-22-0302	Electric	4/15/2022	223,391	5.94	7.85	49.45	13,883,024	11/17/2022	223,391	5.94	7.85	49.45	12/31/2021	13,883,023	Year-end	7.20	Distribution	Fully Litigated	No	No
IL	Commonweal	D-23-0055	Electric	1/17/2023	1,487,444	7.65	10.65	51.19	18,330,797	12/14/2023	1,053,522	6.71	8.91	50.00	12/31/2027	17,330,861	Average	11.03	Distribution	Fully Litigated	Yes	No
IL	Ameren Illinoi	D-23-0082	Electric	1/20/2023	465,064	7.76	10.50	54.03	5,193,859	12/14/2023	309,355	6.59	8.72	50.00	12/31/2027	4,803,776	Average	10.93	Distribution	Fully Litigated	Yes	No
MA	Fitchburg Gas	DPU 15-80	Electric	6/16/2015	3,812	8.72	10.25	52.92	57,252	4/29/2016	2,135	8.46	9.80	52.17	12/31/2014	57,159	Year-end	10.60	Distribution	Fully Litigated	No	No
MA	Massachusett	DPU-15-155	Electric	11/6/2015	201,900	8.13	10.50	51.98	1,799,527	9/30/2016	169,670	7.58	9.90	50.70	6/30/2015	1,783,121	Year-end	10.97	Distribution	Fully Litigated	No	No
MA	NSTAR Electr	DPU 17-05 (N	Electric	1/17/2017	60,194	7.61	10.50	53.37	2,734,403	11/30/2017	-26,039	7.33	10.00	53.34	6/30/2016	2,733,107	Year-end	10.57	Distribution	Fully Litigated	Yes	No
MA	Western Mass	DPU 17-05 (W	Electric	1/17/2017	35,663	7.62	10.50	53.34	440,872	11/30/2017	19,724	7.26	10.00	54.51	6/30/2016	436,418	Year-end	10.57	Distribution	Fully Litigated	Yes	No
MA	Massachusett	DPU-18-150	Electric	11/15/2018	115,953	8.04	10.50	53.49	2,218,491	9/30/2019	90,125	7.56	9.60	53.49	12/31/2017	2,151,481	Year-end	10.63	Distribution	Fully Litigated	Yes	No
MA	Fitchburg Gas	DPU 19-130	Electric	12/17/2019	2,656	8.41	10.50	52.45	77,448	4/17/2020	1,067	7.99	9.70	52.45	12/31/2018	72,207	Year-end	4.07	Distribution	Settled	No	No
MA	NSTAR Electr	DPU 22-22	Electric	1/14/2022	93,443	7.43	10.50	53.21	4,095,188	11/30/2022	64,255	7.06	9.80	53.21	12/31/2020	3,930,069	Year-end	10.67	Distribution	Fully Litigated	Yes	No
MA	Fitchburg Gas	DPU 23-80	Electric	8/17/2023	5,142	8.04	10.50	52.26	84,907	6/28/2024	4,849	7.46	9.40	52.26	12/31/2022	84,754	Year-end	10.53	Distribution	Fully Litigated	Yes	No
MA	Massachusett	DPU 23-150	Electric	11/16/2023	118,300	7.70	10.50	52.83	3,160,000	9/30/2024	90,157	7.09	9.35	52.83	3/31/2023	3,126,537	Year-end	10.63	Distribution	Fully Litigated	Yes	No
MD	Baltimore Gas	C-9406 (elec)	Electric	11/6/2015	115,600	7.95	10.60	53.70	3,003,094	6/3/2016	44,129	7.28	9.75	51.90	11/30/2015	2,934,725	Average	7.00	Distribution	Fully Litigated	No	No
MD	Potomac Elec	C-9418	Electric	4/19/2016	102,751	8.01	10.60	49.55	1,728,572	11/15/2016	52,535	7.49	9.55	49.55	12/31/2015	1,636,944	Average	7.00	Distribution	Fully Litigated	No	No
MD	Delmarva Pov	C-9424	Electric	7/20/2016	56,970	7.24	10.60	49.10	726,802	2/15/2017	38,268	6.74	9.60	49.10	3/31/2016	707,246	Average	7.00	Distribution	Fully Litigated	No	No
MD	Potomac Elec	C-9443	Electric	3/24/2017	67,048	7.74	10.10	50.15	1,683,407	10/20/2017	32,444	7.43	9.50	50.15	4/30/2017	1,638,091	Average	7.00	Distribution	Fully Litigated	No	No
MD	Potomac Elec	C-9472	Electric	1/2/2018	3,252	7.74	10.10	50.44	1,812,762	5/31/2018	-15,000	7.03	9.50	50.44	12/31/2017	NA		4.97	Distribution	Settled	No	No
MD	The Potomac	C-9490	Electric	8/24/2018	17,616	7.75	10.80	52.82	471,124	3/22/2019	6,199	7.15	9.65	52.82	6/30/2018	461,681	Average	7.00	Distribution	Fully Litigated	No	No
MD	Potomac Elec	C-9602	Electric	1/15/2019	26,710	7.81	10.30	50.46	1,973,610	8/12/2019	10,289	7.45	9.60	50.46	1/31/2019	1,958,395	Average	6.97	Distribution	Fully Litigated	No	No
MD	Baltimore Gas	C-9610 (EL)	Electric	5/24/2019	80,665	7.26	10.30	52.00	3,457,321	12/17/2019	25,000	6.94	9.70	NA	7/31/2019	NA		6.90	Distribution	Settled	No	No
MD	Delmarva Pov	C-9630	Electric	12/5/2019	17,492	7.19	10.30	50.53	852,620	7/14/2020	11,715	6.84	9.60	50.53	8/31/2019	844,573	Average	7.40	Distribution	Fully Litigated	No	No
MD	Baltimore Gas	C-9645 (EL)	Electric	5/15/2020	136,989	7.09	10.10	52.00	4,714,006	12/16/2020	139,909	6.75	9.50	52.00	12/31/2023	4,315,215	Average	7.17	Distribution	Fully Litigated	Yes	No
MD	Potomac Elec	C-9655	Electric	10/26/2020	104,059	7.54	10.20	50.50	2,585,603	6/28/2021	52,244	7.21	9.55	50.50	3/31/2024	2,265,511	Average	8.17	Distribution	Fully Litigated	Yes	No
MD	Delmarva Pov	C-9681	Electric	5/19/2022	37,386	6.95	10.25	50.50	1,023,803	12/14/2022	28,917	6.62	9.60	50.50	12/31/2025	992,865	Average	6.97	Distribution	Settled	Yes	No

Schedule MLR-8c: Electric rate cases for CY 2015-2025

where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025

available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
MD	Baltimore Gas	C-9692 (EL)	Electric	2/17/2023	313,893	7.56	10.40	52.00	5,593,441	12/14/2023	179,085	6.77	9.50	52.00	12/23/2026	5,197,916	Average	10.00	Distribution	Fully Litigated	Yes	No
MD	The Potomac	C-9695	Electric	3/22/2023	50,389	7.54	10.60	53.53	718,507	10/18/2023	28,746	6.92	9.50	53.00	12/31/2022	680,418	Average	7.00	Distribution	Fully Litigated	No	No
MD	Potomac Elec	C-9702	Electric	5/16/2023	187,912	7.81	10.50	50.50	2,969,437	6/10/2024	44,629	7.13	9.50	50.50	3/30/2024	2,408,076	Average	13.03	Distribution	Fully Litigated	No	No
ME	Versant Powe	D-2015-0036(	Electric	3/21/2016	7,222	7.72	10.25	49.00	262,813	12/19/2016	3,002	7.45	9.00	49.00	12/31/2014	259,642	Average	9.10	Distribution	Fully Litigated	No	No
ME	Versant Powe	D-2017-0019ß	Electric	10/2/2017	10,043	7.25	9.50	49.00	307,312	6/28/2018	4,454	7.18	9.35	49.00	12/31/2016	292,869	Average	8.97	Distribution	Fully Litigated	No	No
ME	Central Maine	D-2018-0019	Electric	10/15/2018	44,781	7.45	10.00	55.00	952,466	2/19/2020	17,420	6.30	8.25	50.00	6/30/2018	939,452	Average	16.40	Distribution	Fully Litigated	No	No
ME	Versant Powe	D-2020-0031	Electric	1/19/2021	19,625	6.76	9.35	49.00	418,480	10/28/2021	15,424	6.57	9.35	49.00	12/31/2019	409,304	Average	9.40	Distribution	Fully Litigated	No	No
ME	Central Maine	D-2022-0015	Electric	8/11/2022	43,530	7.14	10.20	50.00	1,200,978	6/6/2023	67,000	6.74	9.35	50.00		NA		9.97	Distribution	Settled	Yes	No
ME	Versant Powe	D-2022-0025	Electric	10/3/2022	33,133	6.59	9.35	49.00	525,863	5/31/2023	30,358	6.59	9.35	49.00	12/31/2021	526,912	Average	8.00	Distribution	Settled	Yes	No
NH	Liberty Utilities	D-DE-16-383	Electric	4/29/2016	5,685	8.31	10.30	55.00	96,585	4/12/2017	3,750	7.64	9.40	50.00	12/31/2015	NA		11.60	Distribution	Settled	Yes	Yes
NH	Unitil Energy	D-DE-16-384	Electric	4/29/2016	6,562	8.75	10.30	50.97	152,235	4/20/2017	4,109	8.34	9.50	50.97	12/31/2015	NA		11.87	Distribution	Settled	Yes	Yes
NH	Public Service	D-DE-19-057	Electric	5/28/2019	69,254	7.62	10.40	54.85	1,215,690	12/15/2020	44,987	6.87	9.30	54.40	12/31/2018	NA	Year-end	18.90	Distribution	Settled	Yes	Yes
NH	Liberty Utilities	D-DE-19-064	Electric	4/30/2019	6,673	8.19	10.00	55.00	103,024	6/30/2020	4,150	7.60	9.10	52.00	12/31/2018	NA	Year-end	14.23	Distribution	Settled	Yes	Yes
NH	Unitil Energy	D-DE-21-030	Electric	4/2/2021	11,992	7.88	10.00	52.91	226,030	5/12/2022	5,883	7.42	9.20	52.00	12/31/2020	223,633		13.50	Distribution	Settled	Yes	Yes
NJ	Jersey Centra	D-ER-121110	Electric	11/30/2012	10,957	8.66	11.00	53.80	2,024,166	3/18/2015	-114,993	8.01	9.75	50.00	12/31/2011	1,830,023	Year-end	27.93	Distribution	Fully Litigated	No	No
NJ	Atlantic City E	D-ER-160302	Electric	3/22/2016	79,400	8.06	10.60	49.48	1,300,000	8/24/2016	45,000	7.64	9.75	49.48	12/31/2015	1,205,956	Year-end	5.17	Distribution	Settled	No	No
NJ	Jersey Centra	D-ER-160403	Electric	4/28/2016	142,109	8.69	11.20	54.00	2,229,134	12/12/2016	80,000	7.47	9.60	45.00	6/30/2016	2,217,125	Year-end	7.60	Distribution	Settled	No	No
NJ	Rockland Elec	D-ER-160504	Electric	5/13/2016	8,760	7.79	10.20	49.81	190,117	2/22/2017	1,700	7.47	9.60	49.70	12/31/2016	178,727	Year-end	9.50	Distribution	Settled	No	No
NJ	Atlantic City E	D-ER-170303	Electric	3/30/2017	84,600	7.85	10.10	50.47	1,405,438	9/22/2017	43,000	7.60	9.60	50.47	7/31/2017	1,316,151	Year-end	5.87	Distribution	Settled	No	No
NJ	Public Service	D-ER180100	Electric	1/12/2018	172,712	7.36	10.30	54.00	5,664,074	10/29/2018	88,900	6.99	9.60	54.00	6/30/2018	5,476,000	Year-end	9.67	Distribution	Settled	No	Yes
NJ	Atlantic City E	D-ER180809	Electric	8/21/2018	130,233	7.33	10.10	49.94	1,592,612	3/13/2019	70,000	7.08	9.60	49.94	12/31/2018	1,494,596	Year-end	6.80	Distribution	Settled	No	No
NJ	Rockland Elec	D-ER190505	Electric	5/3/2019	20,309	7.37	9.60	50.16	253,275	1/22/2020	12,000	7.11	9.50	48.32	9/30/2019	229,875	Year-end	8.80	Distribution	Settled	No	No
NJ	Jersey Centra	D-ER200201	Electric	2/18/2020	185,338	7.76	10.15	52.80	2,623,044	10/28/2020	94,000	7.40	9.60	51.44	6/30/2020	2,623,044	Year-end	8.43	Distribution	Settled	No	No
NJ	Atlantic City E	D-ER201207	Electric	12/9/2020	66,841	7.34	10.30	50.18	1,822,193	7/14/2021	41,000	6.99	9.60	50.21	12/31/2020	1,770,614	Year-end	7.23	Distribution	Settled	No	No
NJ	Rockland Elec	D-ER210508	Electric	5/21/2021	19,505	7.28	10.00	48.84	285,235	12/15/2021	9,650	7.08	9.60	48.51	9/30/2021	262,826	Year-end	6.93	Distribution	Settled	No	No
NJ	Atlantic City E	D-ER230200	Electric	2/15/2023	91,990	7.13	10.50	50.20	2,243,893	11/17/2023	45,000	6.58	9.60	50.20	6/30/2023	2,118,727	Year-end	9.17	Distribution	Settled	Yes	No
NJ	Jersey Centra	D-ER230301	Electric	3/16/2023	192,250	7.60	10.40	51.90	3,049,777	2/14/2024	85,000	7.18	9.60	51.90	6/30/2023	2,960,587	Year-end	11.17	Distribution	Settled	No	No
NJ	Public Service	D-ER231209	Electric	12/29/2023	560,915	7.54	10.40	55.50	9,642,298	10/9/2024	440,500	7.07	9.60	55.00	5/31/2024	9,300,000	Year-end	9.50	Distribution	Settled	No	No
NY	Central Hudsc	C-14-E-0318	Electric	7/25/2014	40,121	6.82	9.00	48.00	850,813	6/17/2015	15,346	6.62	9.00	48.00	6/30/2016	830,092	Average	10.90	Distribution	Settled	Yes	No
NY	Orange and R	C-14-E-0493	Electric	11/14/2014	33,914	7.51	9.75	48.00	821,552	10/15/2015	9,326	7.10	9.00	48.00	10/31/2016	763,162	Average	11.17	Distribution	Settled	Yes	No
NY	Consolidated	C-15-E-0050/	Electric	1/30/2015	368,100	7.35	10.00	48.00	18,134,000	6/17/2015	0	6.91	9.00	48.00	12/31/2016	18,282,000	Average	4.60	Distribution	Settled	No	No
NY	New York Sta	C-15-E-0283	Electric	5/20/2015	123,800	7.32	10.06	50.00	1,797,603	6/15/2016	29,601	6.68	9.00	48.00	4/30/2017	1,752,851	Average	13.07	Distribution	Settled	Yes	No
NY	Rochester Ga	C-15-E-0285	Electric	5/20/2015	42,521	8.15	10.06	50.00	1,240,693	6/15/2016	3,000	7.55	9.00	48.00	4/30/2017	1,146,361	Average	13.07	Distribution	Settled	No	No
NY	Consolidated	C-16-E-0060	Electric	1/29/2016	479,610	7.31	9.75	48.00	18,926,574	1/24/2017	194,500	6.82	9.00	48.00	12/31/2017	18,902,000	Average	12.03	Distribution	Settled	Yes	No
NY	Niagara Moha	C-17-E-0238	Electric	4/28/2017	260,959	6.93	9.79	48.00	5,207,221	3/15/2018	159,974	6.53	9.00	48.00	3/31/2019	5,260,727	Average	10.70	Distribution	Settled	Yes	No
NY	Central Hudsc	C-17-E-0459	Electric	7/28/2017	63,407	6.99	9.50	50.00	983,391	6/14/2018	19,725	6.44	8.80	48.00	6/30/2019	999,482	Average	10.70	Distribution	Settled	Yes	No
NY	Orange and R	C-18-E-0067	Electric	1/26/2018	30,365	7.35	9.75	48.00	877,642	3/14/2019	13,382	6.97	9.00	48.00	12/31/2019	877,793	Average	13.73	Distribution	Settled	Yes	No
NY	Consolidated	C-19-E-0065	Electric	1/31/2019	469,610	7.19	9.75	50.00	21,835,672	1/16/2020	113,251	6.61	8.80	48.00	12/31/2020	21,659,543	Average	11.67	Distribution	Settled	Yes	No
NY	New York Sta	C-19-E-0378	Electric	5/20/2019	162,679	6.61	9.50	50.00	2,445,936	11/19/2020	45,300	6.10	8.80	48.00	3/31/2021	2,441,222	Average	18.30	Distribution	Settled	Yes	No
NY	Rochester Ga	C-19-E-0380	Electric	5/20/2019	38,697	7.07	9.50	50.00	1,517,072	11/19/2020	21,400	6.62	8.80	48.00	3/31/2021	1,500,901	Average	18.30	Distribution	Settled	Yes	No
NY	Niagara Moha	C-20-E-0380	Electric	7/31/2020	103,320	6.31	9.50	48.00	6,488,502	1/20/2022	49,379	6.08	9.00	48.00	6/30/2022	6,481,479	Average	17.93	Distribution	Settled	Yes	No
NY	Central Hudsc	C-20-E-0428	Electric	8/27/2020	32,792	6.61	9.10	50.00	1,277,937	11/18/2021	-3,017	6.48	9.00	50.00	6/30/2022	1,278,935	Average	14.93	Distribution	Settled	Yes	No
NY	Orange and R	C-21-E-0074	Electric	1/29/2021	27,829	7.03	9.50	50.00	1,041,932	4/14/2022	4,939	6.77	9.20	48.00	12/31/2022	1,021,008	Average	14.67	Distribution	Settled	Yes	No
NY	Consolidated	C-22-E-0064	Electric	1/28/2022	1,037,788	7.14	10.00	50.00	26,408,343	7/20/2023	442,306	6.75	9.25	48.00	12/31/2023	26,094,576	Average	17.93	Distribution	Settled	Yes	No
NY	New York Sta	C-22-E-0317	Electric	5/26/2022	274,445	6.95	10.20	50.00	3,926,456	10/12/2023	137,274	6.40	9.20	48.00	4/30/2024	3,747,889	Average	16.80	Distribution	Settled	Yes	No
NY	Rochester Ga	C-22-E-0319	Electric	5/26/2022	93,364	7.24	10.20	50.00	2,172,276	10/12/2023	50,965	6.67	9.20	48.00	4/30/2024	2,202,482	Average	16.80	Distribution	Settled	Yes	No
NY	Central Hudsc	C-23-E-0418	Electric	7/31/2023	128,708	7.15	9.80	50.00	1,807,392	7/18/2024	74,418	6.92	9.50	48.00	6/30/2025	1,787,977	Average	11.77	Distribution	Fully Litigated	No	No
OH	The Dayton P	C-15-1830-EL	Electric	11/30/2015	65,772	7.86	10.50	50.00	683,779	9/26/2018	29,785	7.27	10.00	47.52	5/31/2016	643,519	Date Certain	34.37	Distribution	Settled	No	No
OH	Duke Energy	C-17-0032-EL	Electric	3/2/2017	15,405	7.82	10.40	50.75	1,338,485	12/19/2018	-19,177	7.54	9.84	50.75	3/31/2017	1,302,465	Date Certain	21.90	Distribution	Settled	No	No

Schedule MLR-8c: Electric rate cases for CY 2015-2025
where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025
available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested					Increase Authorized													
State	Company	Case identificatio n	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
OH	Ohio Power C	C-20-0585-EL	Electric	6/1/2020	402,086	7.90	10.15	54.43	3,105,270	11/17/2021	294,729	7.28	9.70	54.43	11/30/2020	3,088,389	Date Certain	17.80	Distribution	Settled	No	No
OH	The Dayton P	C-20-1651-EL	Electric	11/30/2020	120,772	7.71	10.50	53.87	796,384	12/14/2022	75,617	7.43	10.00	53.87	5/31/2021	783,478	Date Certain	24.80	Distribution	Fully Litigated	No	No
OH	Duke Energy (	C-21-0887-EL	Electric	10/1/2021	54,687	7.26	10.30	50.50	2,068,551	12/14/2022	22,594	6.86	9.50	50.50	3/31/2022	2,037,893	Date Certain	14.63	Distribution	Settled	No	No
PA	UGI Utilities, I	D-R-2017-264	Electric	1/26/2018	7,705	8.24	11.25	54.02	119,242	10/4/2018	3,201	7.48	9.85	54.02	9/30/2019	94,851	Year-end	8.37	Distribution	Fully Litigated	No	No
RI	The Narragan	D-4770 (electr	Electric	11/27/2017	18,878	7.43	10.10	50.97	730,084	8/24/2018	28,900	6.97	9.28	50.95	6/30/2017	734,837	Average	9.00	Distribution	Settled	Yes	No
TX	Oncor Electric	D-46957	Electric	3/17/2017	316,880	7.75	10.25	45.00	10,989,502	9/28/2017	118,094	7.44	9.80	42.50	12/31/2016	10,991,993	Year-end	6.50	Distribution	Settled	No	Yes
TX	Texas-New M	D-48401	Electric	5/30/2018	31,283	8.85	10.50	50.00	522,411	12/20/2018	22,786	7.89	9.65	45.00	12/31/2017	520,298	Year-end	6.80	Distribution	Settled	No	No
TX	CenterPoint E	D-49421	Electric	4/5/2019	188,867	7.39	10.40	50.00	6,415,236	2/14/2020	55,942	6.51	9.40	42.50	12/31/2018	6,266,073	Year-end	10.50	Distribution	Settled	No	No
TX	AEP Texas In	D-49494	Electric	5/1/2019	59,076	7.08	10.50	45.00	2,433,985	2/27/2020	743	6.45	9.40	42.50	12/31/2018	2,403,986	Year-end	10.07	Distribution	Settled	No	No
TX	Oncor Electric	D-53601	Electric	5/13/2022	250,691	7.05	10.30	45.00	18,815,928	3/9/2023	100,536	6.65	9.70	42.50	12/31/2021	18,618,610	Year-end	10.00	Distribution	Fully Litigated	No	No
TX	AEP Texas In	D-56165	Electric	2/29/2024	100,387	7.18	10.60	45.00	4,248,453	10/3/2024	45,499	6.66	9.76	42.50	9/30/2023	4,273,499	Year-end	7.23	Distribution	Settled	No	No

Return on Rate Base (%)	
Mean	6.99
Standard E	0.05
Median	6.99
Mode	7.08
Standard D	0.50
Sample Vai	0.25
Kurtosis	0.41
Skewness	0.08
Range	2.74
Minimum	5.72
Maximum	8.46
Sum	762.17
Count	109.00

Schedule MLR-8d: Electric Rate Cases for CY 2015-2025 (Only ROR rates higher than 7.85%)
where the state regulator approved an ROE, based on S&P MI data as of 3/18/2025
available at: S&P Capital IQ (https://www.capitaliq.spglobal.com/web/client?auth=inherit#office/screener?perspective=238101)

				Increase Requested						Increase Authorized												
State	Company	Case identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-In? Yes/No	Interim Authorized? Yes/No
MA	Fitchburg Gas	DPU 15-80	Electric	6/16/2015	3,812	8.72	10.25	52.92	57,252	4/29/2016	2,135	8.46	9.80	52.17	12/31/2014	57,159	Year-end	10.60	Distribution	Fully Litigated	No	No
MA	Fitchburg Gas	DPU 19-130	Electric	12/17/2019	2,656	8.41	10.50	52.45	77,448	4/17/2020	1,067	7.99	9.70	52.45	12/31/2018	72,207	Year-end	4.07	Distribution	Settled	No	No
NH	Unitil Energy S	D-DE-16-384	Electric	4/29/2016	6,562	8.75	10.30	50.97	152,235	4/20/2017	4,109	8.34	9.50	50.97	12/31/2015	NA		11.87	Distribution	Settled	Yes	Yes
NJ	Jersey Centra	D-ER-121110	Electric	11/30/2012	10,957	8.66	11.00	53.80	2,024,166	3/18/2015	-114,993	8.01	9.75	50.00	12/31/2011	1,830,023	Year-end	27.93	Distribution	Fully Litigated	No	No
TX	Texas-New M	D-48401	Electric	5/30/2018	31,283	8.85	10.50	50.00	522,411	12/20/2018	22,786	7.89	9.65	45.00	12/31/2017	520,298	Year-end	6.80	Distribution	Settled	No	No

Pennsylvania Public Utility Commission v. Pike County Light & Power Company- Electric;
Docket No. R-2024-3052359

PIKE COUNTY LIGHT & POWER COMPANY- ELECTRIC DIVISION'S RESPONSES TO OFFICE OF CONSUMER ADVOCATE'S INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 6

4. Referencing Lenns and Lenns Testimony at 20:18-21 and Exhibit E-2, Schedule 3, provide support for the Company's proposed return on equity of 9.75%. Include relevant case numbers and PUC decisions in your response, along with copies of all supporting PUC decisions and all filed rate of return testimony.

RESPONSE: Refer to the "DSIC Charge Return on Equity" attachment provided. The Company stated in the testimony that the 9.75% is the rounded return on equity from the Electric Distribution System Improvement Charge ("DSIC") Eligible Utilities Return on Equity Summary, which is included on page 15 of 30 on the PDF file. The return on equity published is 9.75%. This report is published on the Pennsylvania Public Utility Commission's website under the "Filing & Resources" section, then under the "Reports" you will see "Quarterly Earnings Summary Reports." This report is published every quarter with the commission approved return on equity number.

PROVIDED BY: Matthew Lenns, Controller

DATE: March 3, 2025

Pennsylvania Public Utility Commission v. Pike County Light & Power Company- Electric; Docket No. R-2024-3052359

PIKE COUNTY LIGHT & POWER COMPANY- ELECTRIC DIVISION'S RESPONSES TO OFFICE OF CONSUMER ADVOCATE'S INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 6

3. Referencing Lenns and Lenns Testimony at 20:6-8, provide support and all underlying documentation and live excel files for the referenced 50/50 split between debt and equity of other companies.

RESPONSE: Refer to the "CEC – Capital Structure" Excel attachment provided for the referenced 50/50 split between debt and equity of the other regulated companies included in Corning Energy Corporation as of September 30, 2022, 2023 and 2024.

PROVIDED BY: Matthew Lenns, Controller

DATE: March 3, 2025

Corning Energy Corporaion
Capitalzation Structures - for the 12 months ended September 30, 2024, 2023 and 2022

CNG	As of September 30, 2024		As of September 30, 2023		As of September 30, 2022	
	Amount	Percent	Amount	Percent	Amount	Percent
Long Term Debt:	$ 40,986,396	41.36%	$ 33,457,269	38.30%	$ 33,784,002	40.07%
Short Term Debt	8,920,167	9.00%	11,056,149	12.66%	10,023,439	11.89%
Proprietary Capital						
Common Stock	11,323,855		11,323,855		11,323,855	
Paid In Capital	25,056,346		17,564,045		16,947,952	
Retained Earnings	12,806,104		13,955,957		12,229,653	
Total Proprietary Capital:	49,186,305	49.64%	42,843,857	49.04%	40,501,460	48.04%
Total Capitalization	$ 99,092,868	100.00%	$ 87,357,275	100.00%	$ 84,308,901	100.00%

Pike	As of September 30, 2024		As of September 30, 2023		As of September 30, 2022	
	Amount	Percent	Amount	Percent	Amount	Percent
Long Term Debt:	$ 17,584,425	44.69%	$ 15,285,318	44.42%	$ 14,542,993	46.43%
Short Term Debt	2,006,792	5.10%	2,617,121	7.61%	2,004,314	6.40%
Proprietary Capital						
Common Stock	-		-		-	
Paid In Capital	12,450,000		9,950,000		9,600,000	
Retained Earnings	7,303,955		6,556,768		5,173,799	
Total Proprietary Capital:	19,753,955	50.21%	16,506,768	47.97%	14,773,799	47.17%
Total Capitalization	$ 39,345,172	100.00%	$ 34,409,207	100.00%	$ 31,321,106	100.00%

LGC	As of September 30, 2024		As of September 30, 2023		As of September 30, 2022	
	Amount	Percent	Amount	Percent	Amount	Percent
Long Term Debt:	$ 6,414,257	53.33%	$ 5,591,314	44.33%	$ 5,992,918	44.47%
Short Term Debt	265,311	2.21%	1,368,632	10.85%	1,223,473	9.08%
Proprietary Capital						
Common Stock	-		-		-	
Paid In Capital	60,000		-		-	
Retained Earnings	5,288,170		5,652,326		6,259,495	
Total Proprietary Capital:	5,348,170	44.47%	5,652,326	44.82%	6,259,495	46.45%
Total Capitalization	$ 12,027,738	100.00%	$ 12,612,272	100.00%	$ 13,475,886	100.00%

HoldCo	As of September 30, 2024		As of September 30, 2023		As of September 30, 2022	
	Amount	Percent	Amount	Percent	Amount	Percent
Long Term Debt:	$ 70,000,000	63.40%	$ -	0.00%	$ -	0.00%
Short Term Debt	12,000,000	10.87%	-	0.00%	-	0.00%
Proprietary Capital						
Common Stock	100		100		100	
Paid In Capital	44,627,806		39,877,806		38,268,398	
Retained Earnings	(16,218,103)		(14,600,354)		(14,159,759)	
Total Proprietary Capital:	28,409,803	25.73%	25,277,552	100.00%	24,108,739	100.00%
Total Capitalization	$ 110,409,803	100.00%	$ 25,277,552	100.00%	$ 24,108,739	100.00%

Corning Energy Corporaion
Capitalzation Structures - for the 12 months ended September 30, 2024, 2023 and 2022

CNG	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	40,986,396	41.36%	$	33,457,269	38.30%	$	33,784,002	40.07%
Short Term Debt		8,920,167	9.00%		11,056,149	12.66%		10,023,439	11.89%
Proprietary Capital									
Common Stock		11,323,855			11,323,855			11,323,855	
Paid In Capital		25,056,346			17,564,045			16,947,952	
Retained Earnings		12,806,104			13,955,957			12,229,653	
Total Proprietary Capital:		49,186,305	49.64%		42,843,857	49.04%		40,501,460	48.04%
Total Capitalization	$	99,092,868	100.00%	$	87,357,275	100.00%	$	84,308,901	100.00%

Pike	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	17,584,425	44.69%	$	15,285,318	44.42%	$	14,542,993	46.43%
Short Term Debt		2,006,792	5.10%		2,617,121	7.61%		2,004,314	6.40%
Proprietary Capital									
Common Stock		-			-			-	
Paid In Capital		12,450,000			9,950,000			9,600,000	
Retained Earnings		7,303,955			6,556,768			5,173,799	
Total Proprietary Capital:		19,753,955	50.21%		16,506,768	47.97%		14,773,799	47.17%
Total Capitalization	$	39,345,172	100.00%	$	34,409,207	100.00%	$	31,321,106	100.00%

LGC	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	6,414,257	53.33%	$	5,591,314	44.33%	$	5,992,918	44.47%
Short Term Debt		265,311	2.21%		1,368,632	10.85%		1,223,473	9.08%
Proprietary Capital									
Common Stock		-			-			-	
Paid In Capital		60,000			-			-	
Retained Earnings		5,288,170			5,652,326			6,259,495	
Total Proprietary Capital:		5,348,170	44.47%		5,652,326	44.82%		6,259,495	46.45%
Total Capitalization	$	12,027,738	100.00%	$	12,612,272	100.00%	$	13,475,886	100.00%

HoldCo	As of September 30, 2024			As of September 30, 2023			As of September 30, 2022		
		Amount	Percent		Amount	Percent		Amount	Percent
Long Term Debt:	$	70,000,000	63.40%	$	-	0.00%	$	-	0.00%
Short Term Debt		12,000,000	10.87%		-	0.00%		-	0.00%
Proprietary Capital									
Common Stock		100			100			100	
Paid In Capital		44,627,806			39,877,806			38,268,398	
Retained Earnings		(16,218,103)			(14,600,354)			(14,159,759)	
Total Proprietary Capital:		28,409,803	25.73%		25,277,552	100.00%		24,108,739	100.00%
Total Capitalization	$	110,409,803	100.00%	$	25,277,552	100.00%	$	24,108,739	100.00%

Pennsylvania Public Utility Commission v. Pike County Light & Power Company- Electric;
Docket No. R-2024-3052359

PIKE COUNTY LIGHT & POWER COMPANY- ELECTRIC DIVISION'S RESPONSES TO OFFICE OF CONSUMER ADVOCATE'S INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 2

11. Please provide a copy of all the major bond rating agency reports that cover the parent company and Company that were issued from the past five years, to the most currently available.

RESPONSE: Corning Energy Company has had only one bond rating, which was provided as part of the debt refinancing executed on September 12, 2024. The rating was performed by the Kroll Bond Rating Agency, LLC ("KBRA"). Refer to the "Q11" attachments provided for the issuer obligation rating letter and final rating report.

PROVIDED BY: Matthew Lenns, Controller, and Charles Lenns, Senior Vice President & Chief Financial Officer

DATE: February 14, 2025

Corning Energy Corporation

$50 Million Series A Senior Secured Notes due 2034
$20 Million Series B Senior Secured Notes due 2036

Analytical Contacts

Rebecca Dhaniram, Senior Analyst
+1 (646) 731-1346
rebecca.dhaniram@kbra.com

Adam Gracely, Senior Director
+1 (646) 731-3329
adam.gracely@kbra.com

Andrew Giudici, Senior Managing Director
+1 (646) 731-2372
andrew.giudici@kbra.com

Table of Contents

The ratings described in this report are unpublished, confidential ratings that will not be published or otherwise made publicly available by KBRA. This report is provided with the understanding that the Issuer will maintain the existence and content of this report as confidential, and will not use these ratings to market any securities, except to disclose this report to a limited number of investors, each of which (A) is bound by appropriate confidentiality obligations and has a need to know such information, (B) is a sophisticated financial institution with experience in evaluating investments such as the debt instruments described in this report and has performed its own evaluation of the transaction structure and the underlying assets, and (C) will not be relying on the rating for its investment decision, but requested and will use the report to satisfy regulatory requirements, the conditions of internal investment authorizations, or for purposes supplemental to the foregoing. The ratings set forth in this report are subject to all of the terms and conditions set forth in KBRA's website, which any party receiving this report or the ratings described herein should review and understand.

Assignment of Ratings

KBRA assigns its unpublished BB issuer rating to Corning Energy Corporation. KBRA also assigns its unpublished BBB- issue rating to Corning Energy's $50 million Series A senior secured notes and $20 million Series B senior secured notes. The Outlook is Stable.

Corning Energy is a natural gas and electric distributor with three operating businesses – Corning Natural Gas Corporation, Pike County Light & Power, and Leatherstocking Gas Company. To assign the rating, KBRA applied its General Corporate Global Rating Methodology, published on November 28, 2017; Corporate Instrument Notching Global Methodology, published on September 9, 2020; and ESG Global Rating Methodology, published on June 16, 2021. This report is based on information regarding the issuer and its issuance as of September 10, 2024.

Issuer Rating	
Entity	**KBRA Rating/Outlook**
Corning Energy Corporation	BB/Stable

Corning Energy Corporation		
Securities	**PPN**	**KBRA Rating/Outlook**
$50 Million, 6.29% fixed rate, Series A Senior Secured Notes due 2034	21931# AA4	BBB-/Stable
$20 Million, 6.37% fixed rate, Series B Senior Secured Notes due 2036	21931# AB2	BBB-/Stable

Transaction Overview

Corning Energy Corporation (Corning Energy) has engaged KBRA to rate $50 million, 6.29% fixed rate, Series A senior secured notes due 2034 and $20 million, 6.37% fixed rate, Series B senior secured notes due 2036. The proceeds of the issuance will be used to refinance the existing debt of the company's three regulated utility subsidiaries and consolidate all debt at Corning Energy.

The notes have a bullet maturity. Corning Energy will have an option to prepay the notes prior to maturity at a price equal to the principal amount plus a Make-Whole amount determined at the time of prepayment. As a part of the transaction, the company will also solicit a new $30 million revolving credit facility provided by Citizens Bank, which KBRA is not rating. The target closing date of the transaction is September 12, 2024.

Under the transaction structure, the subsidiaries will not be co-borrowers or guarantors under the notes. The notes will be secured only by the stock of each of the issuer subsidiaries; no assets of any of the subsidiaries are pledged.

For financial covenants, the company is subject to a consolidated indebtedness to capitalization of less than 65%, which is often seen in regulated utility financings. For any future priority debt issuance, priority debt is not allowed to exceed 15% of consolidated capitalization. For subsidiary debt, the subsidiaries are subject to a debt cap of $2 million in the case of Leatherstocking or Pike, and $5 million in the case of Corning Gas. The company is also subject to an interest coverage ratio of 2.0x.

Company History and Overview

Found in 1904, Corning Energy Corporation is a natural gas and electric utility holding company with three operating businesses: Corning Natural Gas Corporation, Pike County Light & Power, and Leatherstocking Gas Company. The company serves approximately 21,000 customers across a handful of regions in New York state and Pennsylvania. As of 2023, the company generated approximately $47 million in revenue and $13 million in EBITDA. The three subsidiaries of Corning Energy are currently authorized for a total rate base of $136.5 million by its two regulators, New York Public Service Commission (NYPSC) and Pennsylvania Public Utility Commission (PAPUC). The company was publicly traded on the New York Stock Exchange (NYSE) until the recent acquisition by Argo Infrastructure Partners, LP in 2022.

Corning Natural Gas Corporation (CNGC) – 62% of Full-Year (FY) 2023 Revenue and EBITDA

CNGC is the largest of Corning Energy's subsidiaries and operates as a natural gas distribution company with 434 miles of mains, delivering natural gas to approximately 15,000 residential, commercial, industrial, and municipal customers and currently employing 65 people. CNGC deliveries are made across towns and villages, over 400 square miles, through the southern tier and central regions of New York state. CNGC annually transports approximately 8 billion cubic feet (Bcf) of natural gas to commercial, industrial, residential, and wholesale customers. The subsidiary provides gas delivery and transportation services to two other utilities, NYSEG and BEGWS, as well as other local gas producers in New York and Pennsylvania. CNGC also has contracts with Coring Incorporated and Woodhill Municipal Gas Company, a small local utility, to provide maintenance service on their gas lines. The pipeline for CNGC is 434 miles with transport and delivery capacity of 8 Bcf and storage capacity of 736,000 Dth. CNGC is under the jurisdiction of the New York Public Service Commission (NYPSC), which oversees and sets rates for New York gas distribution companies. Currently, CNGC accounts for approximately $89 million, or 65% of Corning Energy's total rate base. For CNGC, the company filed its rate case on July 31, 2024, in which it requested a $13.1 million increase in total rate base to be spread equally across four years. The case is expected to be settled in June 2025.

Pike County Light & Power (PCL&P) – 34% of FY2023 Revenue and 33% of EBITDA

Pike was acquired by the company in 2016 from Orange & Rockland Utilities, Inc., a local utility company owned by ConEdison. Pike provides electric service to approximately 4,900 customers and natural gas services to 1,300 customers. The subsidiary has 11 employees. The natural gas distribution pipeline is 20 miles with transport and delivery capacity of approximately 137,000 Mcf. The subsidiary is an electric and gas utility regulated by Pennsylvania Public Utilities Commission (PAPUC). Pike accounts for approximately $36 million, or 27% of Corning Energy's total rate base. Pike anticipates filing two new rate cases in Q4 2024, which are expected to take effect in summer of 2025.

Leatherstocking Gas Company (LGC) – 4% of FY2023 Revenue and 5% of EBITDA

Headquartered in Montrose, Pennsylvania, Leatherstocking was created in 2014 in a partnership with Mirabito Regulated Industries and was fully acquired in 2020. The subsidiary distributes gas in Susquehanna and Bradford Counties within Pennsylvania. The subsidiary serves approximately 500 customers with four employees. Leatherstocking is also regulated by the PAPUC. Leatherstocking accounts for approximately $11 million, or 8% of Corning Energy's total rate base. Leatherstocking filed with its most recent rate case in July 2022 and was approved in February 2023 for a $645,000 increase in total revenues.

As mentioned, Corning Energy was acquired by Argo Infrastructure Partners, LP in July 2022. Argo Infrastructure Partners, LP is an independent infrastructure investment manager that invests in industries such as regulated utilities, energy, renewables, and transportation. Argo manages over $5 billion of capital on behalf of its institutional investor partners. The company's managed assets include four contracted power generation assets, three utilities serving over 600,000 customers, two electric transmission systems, and one energy storage network.

Key Credit Considerations

	+/–
Credit Enhancing Regulatory Oversight The presence of multiple state regulators that oversees and restricts the financial endeavors of regulated utility operating companies, limits the amount of total debt in the capital structure and other financial policies that decreases the credit risk.	+
Continuous Growth in Rate Base Corning Energy has seen continuous, incremental growth in its rate base across all three of its subsidiaries. The company expects to continue to see gradual growth, primarily from its Pennsylvania service territory, driven by ongoing initiatives to transition residential customers to natural gas usage.	+
Long-standing Presence and Customer Relationships Corning Energy has a long-standing presence within the city of Corning given its operating history of over 100 years. As a result, the company also benefits from established customer relationships in its service territory.	+
Pending Rate Cases CNGC and Pike have upcoming rate cases in 2024 where the company is requesting increases in its rate base. An increase in the company's rate base would be viewed positively; however, it is not expected to be resolved until 2025. An unfavorable rate case outcome is possible, particularly in New York, which could result in limited rate increases or evidence of an increasing regulatory focus on transitioning away from natural gas.	+/-
Limited Scale and Geographic Diversity Corning Energy operates in small scale service territories in the states of New York and Pennsylvania. The limited scale and lack of diversity restricts the company's long-term growth opportunities.	-
Shifting Regulatory Attitude	-

The state of New York has recently been emphasizing a transition to renewable energy to meet its climate change targets outlined in the Climate Leadership and Community Protection Act (CLCPA) passed in 2019. This could heavily impact the company's profitability considering most of its revenue is generated by its operations in New York at CNGC. This is partially offset by the fact that the state of Pennsylvania maintains a favorable view on the expansion of natural gas usage in the region.	
Limited Operating Track Record under a Private Sponsor Corning Energy Corporation has operated as a public company since 2013 with a high level of oversight. With the recent acquisition by Argo Infrastructure Partners, there could potentially be changes in the way the company operates and its financial policies, partially offset by the oversight provided by the utility regulators.	**-**

Issuer Rating Rationale

The BB issuer rating reflects Corning Energy's overall Average business risk profile and a financial risk score of 9.90.

Corning Energy's business risk profile is characterized by its ownership of three utility subsidiaries that benefit from a monopolistic position within their service territories as a regulated utility provider with operations in two states, New York and Pennsylvania. As a result, the company benefits from revenue stability and a cost-of-service model. The company has a long operating track record within its regions of operations with established customer relationships. However, the company has limited corporate scale, which restricts its competitiveness emphasized by the lack of large economic hubs in the region of its operations and the presence of larger utility competitors within the states of New York and Pennsylvania. In comparison to Corning Energy, the larger competitors are better positioned to politically navigate and combat changes in regulations and policies that adversely impact their operations. Additionally, the service territories are also vulnerable to changes in economic activity and downturns as a result of limited population of largely lower middle income residents The company has primarily been restricted to incremental growth that resulted primarily from the regulated nature of its business. Additionally, although the company has long-standing customer relationships, gas volumes are concentrated among its C&I customers which could present challenges for long-term sustainability of customer rates and volumes. Currently, the company has constructive relationships with both its regulators. However, the regulatory environment is a factor KBRA will continue to monitor for further negative developments considering the growing focus on the transition to renewable energy sources, especially in the state of New York. So far, the state of New York has demonstrated continued initiative to further the state's climate change initiatives and meet its emission targets. With continued legislation, the company faces the potential significant regulations that will challenge the ability for future favorable rate cases and growth of its operations in New York.

Corning Energy's financial risk profile reflects its limited size and scale compared to most utility holding companies, given the small service territory of its regulated subsidiaries. The company benefits from adequate profitability as a result of the nature and cost-of-service model for its regulated utilities operations that allows the company to recover prudent costs, as well as earn a return on capital. Following the proposed issuance, Corning Energy is expected to benefit from a cleaner capital structure with debt consolidated at HoldCo level. However, the company's leverage is significant particularly given its scale that reduces overall financial flexibility and buffers.

Rating Table							
Business Risk Profile	**AAA**	**AA**	**A**	**BBB**	**BB**	**B**	**CCC or below**
Strong	<1.5	1.5-4.5	3-7.5	6-10.5	9.5-13.5	--	--
Average Risk	--	<1.5	<3	3-9.5	7.5-12	9-16.5	≥18
Weak	--	--	--	<3	<7.5	<9	<18

Notching Analysis

KBRA applied its Corporate Instrument Notching Global Methodology, updated September 9, 2020, to determine the potential for a notching adjustment of the issue rating based on the issuer rating.

To complete the analysis, KBRA considered recovery in the event of a distressed sale. KBRA notes that defaults involving a utility company with a significant amount of cash flow from regulated operations often involve unique dynamics that are not broadly applicable. Nevertheless, KBRA considered a range of datapoints across the utility industry and other industries with similar business risk characteristics. An EBITDA haircut was applied, along with a distressed sales multiple. Overall KBRA calculates an expected range of recovery that supports two notches of uplift for the senior secured notes relative to the issuer rating.

Outlook

The Stable Outlook reflects KBRA's expectation that Corning Energy will continue to operate with predictable cashflows through its regulated utility operations and generate sufficient cash to meet its debt obligations. The outlook further reflects KBRA's expectation that Corning Energy will continue to see incremental growth over the medium term while prudently managing capital expenditures and overall liquidity.

Sensitivities for Rating Change

An upgrade could occur if Corning Energy delivers sustained growth in regulated rate base across its operating subsidiaries, including significant increases in customer counts and gas volumes from its utility operations in Pennsylvania. This would likely occur through favorable rate case outcomes and franchise expansion. KBRA will look for the company to diversify its cash flows away from the evolving regulatory environment in New York State, as well as reduce overall volume concentration to major C&I customers.	+
A downgrade could occur if Corning Energy's EBITDA/Interest falls below 3.0x for a sustained period, the company experiences significant operational disruptions, or there is a large population or economic activity outflow from its service territories. A downgrade could also occur should New York State introduce legislation that accelerates the transition to alternative energy sources without addressing the future role of natural gas utilities in the state.	-

Business Risk – Average Risk

Business Risk Summary: Corning Energy Corporation		
Determinant	**Weight**	**Business Risk Comment**
Industry Risk	25%	**Strong**: The essential nature of the services provided and the nature of the regulatory protection in which the utility companies are granted natural monopolies with little competition in their service territories. In addition, the regulatory environment is typically supportive, allowing utility companies the opportunity to recover and earn a rate of return based on the costs to provide services.
Competitive Risk	25%	**Average**: This reflects the company's monopolistic position through the ownership of regulated utilities operations, offset by its limited corporate scale and market share and concentrated customer base.
Growth and Corporate Development Risk	15%	**Average**: This reflects the company's focus on incremental organic growth over time in its Pennsylvania service territory, challenging growth prospects in New York, and overall limited capital to allocate to expansion initiatives.
Liquidity and Financial Flexibility Risk	15%	**Average**: In KBRA's opinion, the liquidity and cash flow profile of the company is sufficient to meet its ongoing obligations. The company's liquidity position is expected to benefit from the reimbursement of prudently managed costs and capital expenditures.
Regulatory and Jurisdictional Risk	10%	**Average**: This reflects the fact that Corning Energy generates its revenues and cash flows from its operations in regulated utilities sector, which is subject to a comprehensive regulatory regime. In addition, the company is expected to face additional regulations given an evolving, regulatory environment that is shifting towards the use of renewable energy sources.
Organizational Form, Structure & Ownership Considerations	10%	**Average**: Following its acquisition by Argo Infrastructure in 2022, Corning Energy operates as a private company under the ownership of a private sponsor. As such, the company does not benefit from the same level of oversight as a publicly traded corporation, although KBRA notes that it is subject to more independent oversight than other private companies given its

		status as a regulated utility and the presence of the state regulators, NYPSC and PAPUC.
Total	**100%**	

Industry Risk – 25% – Strong Risk

KBRA views the utility industry risk in the U.S. to be strong, given the essential nature of the services provided and the nature of the regulatory protection in which the utility companies are granted natural monopolies in their service territories with little competition. In addition, the regulatory environment is typically supportive granting utility companies the opportunity to recover and earn a rate of return based on the costs to provide services.

In the U.S., there are generally two types of utilities companies, private and public. Private utilities, called investor-owned utilities (IOU), are private entities that are either owned by public investors or are privately held but are regulated at both the federal level and the state level by regulatory commissions. The Federal Energy Regulatory Commission (FERC) and the various states regulatory commission are responsible for the regulatory oversight of the utilities. These commissions set the retail rates that are charged by the IOUs for their service. The need for regulation of utilities arises primarily because of the natural monopoly characteristics of the industry. To ensure the delivery of safe, adequate, and reliable electric services, the commissions have granted the IOUs exclusive rights to be the sole provider within a region. The retail rates are set at prices that are sufficient to compensate the regulated utility for the costs that it incurs to fulfill its obligation to serve. Usually, the nature of the retail rate is based on a rate of return provision over the utility's cost of service.

The other type of utilities, publicly-owned utilities (POU), are member-owned cooperatives or government- or municipally-owned utilities. POUs are generally exempt from regulation by state regulatory commissions because they are assumed to have the customers' (who are also the owners or voters) best interests in mind when setting rates and service standards. A few states do subject publicly owned utilities to regulatory oversight.

In the U.S, there are approximately 3,200 utilities operating in the U.S., roughly 200 of them are IOUs. The IOUs provide power to almost 75% of all consumers. Utilities' role in the U.S. are usually in three functions: (i) production (gas) or generation (electricity); (ii) transmission; and (iii) distribution. In the U.S., only a small fraction of the 3,200 utilities performs (or have) all three functions. Most of the major IOUs do own generation, transmission, and distribution; however, very few of these own enough generating resources to meet all of their needs. Very few of the POUs own their own generation or transmission. Instead, they rely on other publicly owned generation and transmission (G&T) utilities or IOUs to provide those functions for them. As a result, the vast majority of utilities rely on power purchases agreements (PPA) from others with generation assets to deliver and transmit electric power across the transmission grid to local utility substations connected to distribution lines that serve end user.

Under the regulatory regime, industry revenues and profitability are relatively stable since the regulatory commissions have deemed electricity and natural gas service providers to be natural monopolies because of the economies of scale and the significant capital necessary to build and maintain power plants, transmission and distribution lines and natural gas pipes and plants. As an IOU under the U.S. utility regulatory regime, Corning Energy has limited exposure to the effect of market risks due to its role as a regulated monopoly within its service territories. As such, KBRA scores the company's exposure to market forces and structural risk as Strong.

Within its regulated operations, Corning Energy does not compete on the basis of price or quality; instead, regulation replaces competition as a determinant of price. Corning Energy provides a largely unnegotiable rate for its gas service to the customers based on a formula-based rate plan that includes allowed rate of return over its capital expenditures, operations and maintenance costs, financing costs, and the related costs of service. The company is required to file a rate case with NYPSC and PAPUC that details these projected costs and the rates that will be subsequently charged to customers are then determined in a regulatory proceeding. Currently, Corning Energy operates under a regime in which it is authorized by the NYPSC to earn a return on equity (ROE) of 9.25% as of its most recent rate case filing.

Positive relations with the regulators usually allow utilities to recover prudent capital costs in the charged rates. With positive relations with its regulators, an IOU can typically expect stable cash flows even if there is a slight lag in recovering regulatory approved costs. Specifically pertaining to Pike, the company also benefits from recovery mechanism for its infrastructure investments called Distribution System Improvement Charge (DSIC). The company is able to recover costs related to its capital investment projects, up to 5% of total annual revenues, without the need to file a base rate case, which typically takes at least nine months to be approved. The DSIC mechanism is in place to encourage utilities to invest in needed upgrades and replacement of aging infrastructure by providing faster recovery costs. In order to utilize this recovery mechanism, Corning Energy must submit a Long-Term Investment Infrastructure Plan (LTIPP) for PAPUC approval, which outlines the projects, estimated costs, and forecast timeline of completion. As LTIPP projects are completed, the company can submit the costs to be reimbursed. Therefore, KBRA scores the company's investment requirements and capital intensity as Strong.

At all three of the company's subsidiaries, commodity costs can be passed through to the customers. Corning Energy also has several mechanisms in place to protect itself and by extension, its customers, from shifts in commodity pricing. At CNGC, customer billing rates are adjusted each month to take into account monthly changes in commodity costs. At Pike and Leatherstocking, customer gas rates are adjusted annually, and electric customer rates are twice per year. The company also expects that any fluctuations in cost would receive favorable treatment from the regulators. In addition to hedging its gas supply contracts, during the summer the company typically purchases gas at a cheaper rate and stores up to one heating season supply of gas. Corning Energy also benefits from its close proximity to the Marcellus gas fields, which provides the company with multiple gas pipeline companies to choose from when purchasing gas inventories, further reducing its exposure. In view of this, KBRA views Corning Energy as having limited commodity volatility exposure and scores commodity volatility as Strong.

Competitive Risk – 25% – Average Risk

KBRA scores the competitive risk of Corning Energy as Average, reflecting the core competitive strength afforded to regulated utilities by their control over a service territory, offset by its limited corporate scale and market scale. Additionally, the company's concentrated customer base hinders the overall, long-term sustainability of customer rates and volumes. Although the company has to navigate several operational risks, KBRA believes the company is sufficiently positioned to manage these challenges, supported by certain protections to profitability due to the nature of the regulated utilities rate case filings.

Corning Energy is a small, regulated utility company serving a handful of regions in the states of New York and Pennsylvania. Although the company does not benefit from an extensive corporate scale seen with larger utility holding companies, KBRA scores the company's size & scale as Average, reflecting the exclusivity of the company's service territories it operates in. However, KBRA scores the company's market share as Weak, given the significantly larger competitors with regulated utility operations in both New York and Pennsylvania. In New York State, larger competitors in the region include National Grid, New York State Electric & Gas (NYSEG), Central Hudson Gas & Electric, Rochester Gas & Electric (RG&E), Con Edison, and KeySpan Long Island. These competitors provide services in more highly populated service territories, authorized for a significantly larger rate base, and overall generate greater revenues. National Grid and its various subsidiaries provide natural gas to approximately 600,000 customers in New York with a total rate base of $20.7 billion. NYSEG serves approximately 272,000 natural gas customers with a service territory that spans 40% of upstate New York, and a total rate base of $3.9 billion as of 2022. RG&E provides natural gas services to approximately 320,000 customers across nine counties of New York. In Pennsylvania, the largest providers of natural gas services include Columbia Gas of PA Inc, Natural Fuel Gas, PECO Energy Company, and Philadelphia Gas Works. Columbia Gas provides natural gas to over 445,000 customers in 26 counties in Pennsylvania. Natural Fuel Gas distributes and transports natural gas to hundreds of thousands of customers in Western New York and Northwestern Pennsylvania. PECO provides natural gas distribution service to more than 552,000 customers in southeastern Pennsylvania. Philadelphia Gas Works delivers natural gas to 500,000 customers. The competitors within the two states are substantially larger in terms of customer base, service territory, rate base and also better positioned to navigate and combat future changes in regulations and policy impacting their natural gas operations.

KBRA scores the company's diversity as Average. Corning Energy's customer base across the three subsidiaries consists primarily of residential, commercial, and industrial customers. The company's customer base also includes customers in the transportation sector and has wholesale and local production contracts that also generate a portion of total consolidated revenues. Based on FY 2023 audited data for Corning Energy, as a percentage of total revenues, residential customers accounted for 58.6%, commercial for 23.6%, transportation for 10.6%, with the remaining coming from wholesale contracts (4.6%), industrial customers (1.6%), local production (0.5%), and streetlights (0.4%).

The largest operating utility subsidiary, CNGC, does have significant customer concentration to Corning Inc., which accounts for approximately 49% of total gas volumes sold dating back to January 2019. This is higher customer concentration than we typically see for the average utility company and when compared to peers. Given that CNGC is currently the company's primary generator of revenue and EBITDA, this materially exposes the company's revenues and overall profitability if Corning Inc. no longer continues to be a customer. If this occurred, the company would have difficult sustaining gas volumes at current levels, resulting in higher customer rates to offset loss in volumes which could lead to additional customer churn as energy substitutes become more attractive. This is partially offset by Corning

Energy's long-standing relationship with Corning Inc. and the fact that Corning Inc. is one of the most integral businesses within the city of Corning and its economy. As a result, KBRA views the risk of Corning Inc. leaving the region in the near term as minimal due to Corning Inc's public statement in support of the community. Corning Inc. has also been a leader in initiatives such as revitalization efforts, partnerships with local organizations, and philanthropic investments to help develop and strengthen the local economy. Additionally, CNGC is also concentrated in terms of customer type as a percentage of total gas volumes. Through January 2019 to April 2024, contracted commercial customers accounted for approximately 55% of total gas volumes, with 23% coming from residential, and 18% from transportation customers. The customer concentration at CNGC is mitigated, though only partially, by the well-diversified, unconcentrated customer base at Pike and Leatherstocking.

Corning Energy's customer base is primarily made up of local businesses and retail franchises in its service territory region. For example, Walmart, ShopRite, Home Depot but also local schools, districts, and farms. Corning Energy has long-standing customer relationships with some of the largest employers and economic contributors to the regions they operate in. For CNGC, some of the subsidiary's customers, such as Corning Inc. and Correlle Brands, are major businesses and employers within the city of Corning. CNGC also has multiyear gas pipeline contracts with various counties in the region including Williams and Bath and large industrial, energy, and infrastructure companies such as Kinder Morgan, Repsol, and Eastern Pipeline Company. CNGC also has contracts with counterparties such as New York State Electric & Gas (NYSEG), Corning Inc., Correlle Brands, and Greek Peak ski resort. Pike has multiyear gas and electric supply contracts with entities such as Orange & Rockland. Leatherstocking has customer gas purchase contracts with corporations like Cargill. Overall, despite Corning Energy's small corporate scale, the company has customer relationships with corporations and businesses that have a material impact on the region's economy and community; therefore, KBRA scores the company's contractual revenues, cash flows, and counterparty exposures as Average.

KBRA scores the company's pricing power as Strong considering its monopoly within its service territory and operations within the regulated utility industry. The company operates under a cost-of-service model that determines the rates it charges customers and provides the opportunity for return on investment. This framework is overseen by the NYPSC for CNGC and the PAPUC for Pike and Leatherstocking. Accordingly, a utility's relationship with its regulator is a key competitive factor, considering the direct impact it has on its cash flow generation. KBRA believes that Corning Energy currently has productive relationships with its regulators, with an authorized ROE of 9.25% in New York and consistent, favorable negotiated settlements at Pike and Leatherstocking that has resulted in increasing revenues over the last few years. However, overall authorized ROE is on the lower end of the spectrum for what is seen for utility peers. More importantly, KBRA expects the relationship with regulators, especially the NYPSC, to weaken as the commission is required to tighten regulations on utility companies as the state pursues its climate change initiatives. In Pennsylvania rate cases, the negotiated settlements are a result of "black box" settlements. In black box settlements, the company has proposed, negotiated, and settled with regulators for a blanket rate base increase rather than a specified ROE based on itemized costs in traditional rate cases. These negotiations typically result in an increase in the overall rate base.

KBRA scores the company's operational risk as Average. Corning Energy does have a long operating history track record of 100 years; however, the company must manage a number of operational risks present in its business model especially considering its small scale. One of those challenges is increasing labor costs. Corning Energy has experienced an increase in labor costs, especially with contractors. Under New York state Labor Law, contractors and subcontractors must pay the prevailing rate of wage and supplements to all workers under a public work contract. Employers must pay the prevailing wage rate set for the locality where the work is performed. This applies to all laborers, workers, or mechanics employed under a public work contract. The wage schedules are issued on a county-by-county and annual basis and contain the pay rates for each work classification. Corning Energy has navigated this challenge by reducing the amount of contractors it employs and using it in-house workforce to complete more projects to limit its exposure to increases in labor costs.

Additionally, Corning Energy demonstrated a degree of resiliency in economic downturns and low-probability events, most recently the COVID-19 pandemic. During the pandemic, the company did not have any interruptions in providing its services or incur any regulatory fines or penalties. The company did face the challenge of customers being unable to pay their bills due to loss of employment and due to moratoriums on customer service interruptions with the aid of regulators. During the pandemic, regulators provided cash and liquidity to Corning Energy and other utilities in order to prevent service interruptions and financial hardships. However, given the demographics of Corning, New York, economic activity outflows and downturns are ongoing exposures for the company. As of July 2023, Corning, New York is estimated to have a population of 10,612 which is a slight decrease of 0.2% from the previous year. The city is made up of lower middle income residents with the median income at approximately $59,500 compared to the median income of approximately $76,000 in the New York State.

Geographically, Corning Energy is located on top of the Marcellus Shale gas fields in Pennsylvania. This gives the company a competitive and operational advantage when purchasing and moving supplies to and through its pipeline compared to other competitors that have to account for and accommodate the logistics of shipping supplies. In addition, their location also provides a degree of protection from increasing gas prices. With the Marcellus Shale gas fields, there are a variety of gas pipeline companies to choose from, which offers Corning Energy some flexibility when purchasing its gas inventories in terms of pricing.

Growth and Corporate Development Risk – 10% – Average Risk

KBRA views the growth and corporate development risk as Average. For the company's revenues overall, growth is largely a function of growth in the economy and demand among the customer base. To increase, they would have to experience increased demand from current customers or expand their customer base, leading to additional approved capital projects, incur higher prudently incurred costs or acquire additional service territory in the regions they operate in. Additionally, the management team has indicated that they do not plan on currently pursuing acquisitions to expand their business and expects that growth will primarily come from incremental organic growth driven by their current initiatives to transition residential customers in Pennsylvania to natural gas usage. Overall, growth in the company is restricted by the limited amount of capital the company has to direct toward expansion initiatives.

KBRA scores the company's organic growth as Average. Corning Energy generated $43.5 million in revenues and $16.7 million in EBITDA as of last 12 months (LTM) Q2 2024. For all three subsidiaries, the company has seen continuous increases in rate base. Corning Energy has already been approved for an $8.2 million increase in total revenues through 2026. This results in an incremental increase in total revenues of $2.7 million or approximately 6% annually, beginning in 2024. CNGC accounts for $1.7 million of the total increase in revenues, $0.8 million comes from Pike, and $0.2 million from Leatherstocking. Nevertheless, future organic growth is anticipated to be gradual and will primarily come from the company's service territory in Pennsylvania. At Leatherstocking, the company expects to see significant growth in the customer base, an approximately 30% increase, by 2028. The growth is attributed to natural gas conversion opportunities, particularly among the residential customers, in the service territory. Also at Leatherstocking, the company expects to see additional customer growth through their ongoing program to provide gas appliance financing for its customers, an initiative that is funded by the United States Department of Agriculture. On the other hand, future growth prospects in the company's service territory in New York and at CNGC are expected to be extremely limited with increasing obstacles being created by the regulatory environment.

KBRA scores the company's M&A-driven growth as Average. The company has stated that there is limited capital to pursue expansion initiatives in the near term. Historically, Corning Energy has executed several growth initiatives and acquisitions that proved positive for the growth of the company. In 2014, the company partnered with Mirabito Regulated Industries in a joint venture to form LGC. A few years later, Corning Energy purchased Mirabito's 50% ownership in LGC, becoming the sole owner in 2020. In 2016, Corning Energy acquired Pike Country Light and Power from Orange & Rockland Utilities, Inc. The acquisition expanded the company's operations in Pennsylvania and provided diversity to its business lines with the entrance into electric market.

KBRA scores the company's diversity as Average. Corning Energy has limited diversity in terms of business segments and overall, the company is limited in its capacity to diversity, considering lack of financial resources to dedicate toward expansion, restricted and slow growth in the customer base, and that the support for expansion in its natural gas segment is primarily confined to Pennsylvania, given the NYPSC support for shifting away from natural gas in the state of New York. Additionally, Corning Energy has a degree of diversity in terms of its regulators as opposed to being subject to the regulations and requirements of one regulator. Although the NYPSC has shifted its focus to the transition toward renewable energy sources, the PAPUC remains very supportive of the natural gas providing Corning Energy with growth opportunities.

Liquidity and Financial Flexibility – 10% – Average Risk

KBRA views the liquidity and financial flexibility score of Corning Energy as Average. The company generated $7 million in cash from operations as of LTM Q2 2024 and its largest uses of cash were capital expenditures ($15 million) and purchase of securities ($3 million). In KBRA's opinion, the liquidity and cash flow profile of the company is sufficient to meet its ongoing obligations.

With regulated utilities, there is typically a regulatory lag in recovering natural gas distribution expenditures that can limit the company's ability to build liquidity and its financial flexibility in the interim. As of LTM Q2 2024, the company's sources of cash included $0.2 million of cash on balance sheet and $7 million of available cash from operations. During the same period, Corning Energy's primary use of cash was $15 million in capital expenditures. KBRA views positively the fact that a significant amount of the company's sources is backed by a regulatory revenue requirement and that the company generally limits growth investments to projects that are approved for eventual addition to the regulated rate base. As such KBRA scores the company's sources/uses as Average.

KBRA scores the company's access to capital markets as Average reflecting the company's small scale and limited track record of raising financial in capital markets. Additionally, the Corning Energy is now a privately held company owned by a private sponsor which limits its ability to access public debt or equity markets, restricting its options to raise capital from private placements with lenders that specialize in lower middle market lending. KBRA believes that it would be difficult for the company to find alternative sources of liquidity under unfavorable market conditions. However, the company does not have tight covenant restrictions and was able to raise alternative liquidity in the form of preferred shares for additional financing for the Argo acquisition transaction, as such KBRA scores the company's alternative liquidity as Average.

KBRA scores the company's ability to build liquidity from internal cash flows as Average reflecting the presence of a cost service model and the regulatory provision for the company to earn a rate of return on its rate base. The company is expected to be able to generate sufficient cash from operations through prudently managed costs to provide its regulated services to customers.

Regulatory and Jurisdictional Risk – 10% – Average Risk

KBRA scores the regulatory and jurisdictional risk of Corning Energy as Average. A significant amount of the company's revenues and cash flow is generated from its natural gas operations, which are subjected to a comprehensive regulatory regime and oversight and exposure to legal issues and risks that pose a threat to overall profitability.

While KBRA typically views regulatory support for regulated utilities as Strong, reflecting the stability of the business model and the opportunity to earn supportive returns, KBRA scores Corning Energy's regulatory support as Average. The Average score reflects the fact 62% of the company's revenues and EBITDA and 65% of its total approved rate base is attributable to its operations at CNGC based in New York in a regulatory regime that is shifting toward the use of alternative, renewable energy resources rather than natural gas. On July 18, 2019, the Climate Leadership and Community Protection Act (CLCPA) was signed into law, requiring New York to reduce economywide greenhouse gas emissions by 40% by 2030 and no less than 85% by 2050 from 1990 levels. In May 2023, New York state became the first state in the country to pass a law prohibiting the use of fossil fuel equipment in new construction, a mandate that will take effect in 2026 for new buildings of seven stories or less, and in 2029 for larger buildings. Most recently, the state of New York continued its initiative toward a carbon neutral economy by 2050 by introducing the New York Home Energy Affordable Transition (HEAT) Act into legislation. The legislation seeks to limit a requirement known as the "obligation to serve" where utilities automatically provide gas to new customers who request it, and to curb the expansion of gas infrastructure. This legislation would grant NYPSC new authority to phase out gas use and rollback long-standing subsidies for new gas hookups, essentially decreasing New York citizens' statutory right to gas service, including capping the expansion of gas distribution systems beginning 2026 and giving the NYPSC new authority to decommission parts of the system, provided that the commission determines that retirement is necessary to achieve New York's emission reduction and climate justice goals. Although the New York HEAT Act did not get passed in the recent vote, this is the second time it went up for a vote in the Senate and provides further evidence that New York state will continue to pursue its focus of transitioning away from the use of nonrenewable energy sources.

Corning Energy does benefit from the regulatory support of its second regulator. In Pennsylvania, the PAPUC has a much more favorable outlook for the natural gas industry and its expansion, with support for the continuation of drilling new natural gas wells and with natural gas utilities being approved for significant investments in their infrastructure. However, the service territory and operations in Pennsylvania is smaller than in New York and although there are opportunities for the company to grow its operations in the region, it will take significant time to do so to offset the risks posed by the regulatory environment in New York.

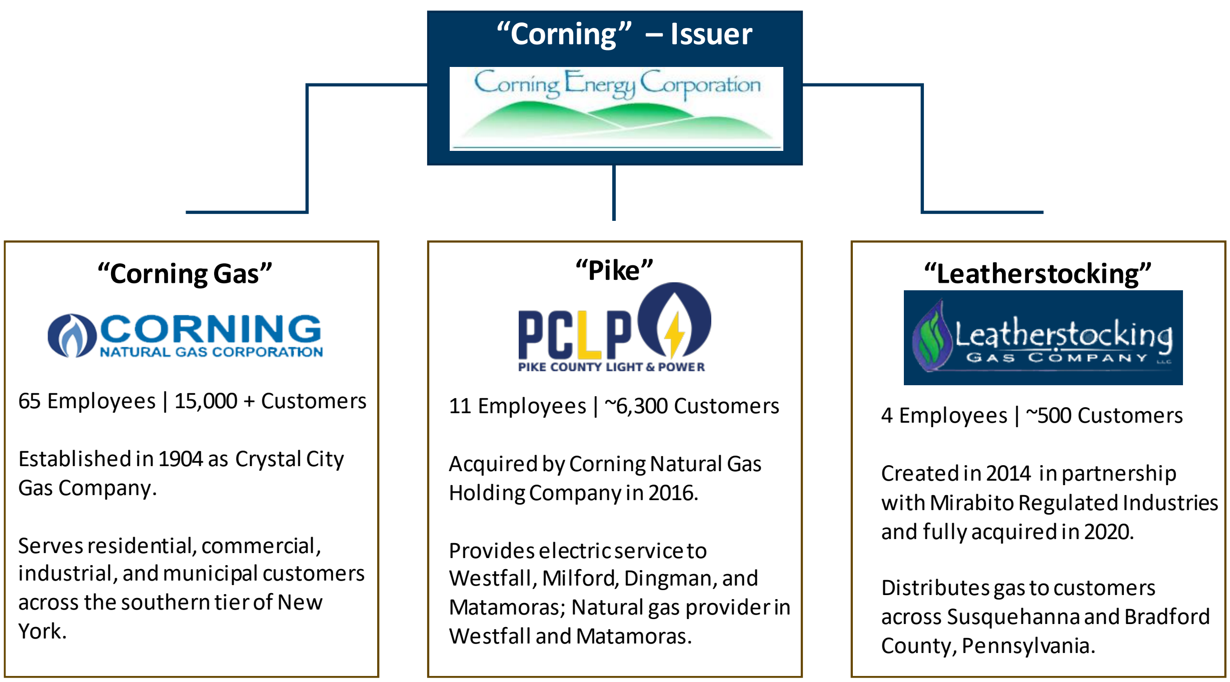
Furthermore, while the regulatory regime affords the company some profitability protection that provides stability to its cash flows, continued legislation and tightening regulatory hurdles impacting Corning Energy's largest subsidiary would deteriorate that protection. Coupled with the adverse legislations mentioned above, KBRA scores the company's legal issues and risks as Average.

KBRA scores the company's permitting process and ease of business development and compliance standards and requirements as Average. Despite past rate case resolutions, the process of obtaining a rate base increase can be lengthy and involves no guarantees of success. Additionally, while the company does operate in a clear and consistent regulatory framework, the approval process for new projects, programs, and rate adjustments can be involved. Requests from utilities can be rejected or settled by the state regulators after a considerable amount of resources have been invested in order to submit filings and documentation and to advocate for various business initiatives. Further, there are no assurances that the company's regulators will approve the recovery of all costs incurred for its operations, including costs for construction, operation and maintenance, and compliance with current regulations. Additionally, as a regulated utility company, Corning Energy is subject to a high level of compliance requirements as a result of regulators.

Organizational Form, Structure, and Ownership Considerations – 10% – Average Risk

KBRA views the organizational form, structure, and ownership as Average. Following its recent acquisition by Argo Infrastructure in 2022, Corning Energy operates as a private company under the ownership of a private sponsor. As such, the company does not benefit from the same level of oversight as a publicly traded corporation, although KBRA notes that it is subject to more independent oversight than most other private companies given its status as a regulated utility and the presence of two regulators, NYPSC and PAPUC. While KBRA believes that private ownership can indicate the potential for aggressive financial policies, the risk is reduced in this case given the nature of the regulated utilities business model and limitations imposed by the regulators. KBRA scores the company's type of corporate form as Average.

KBRA scores the company's overall corporate structure as Average, considering that the group structure is simple and easily understood, with Corning Energy Corporation being the ultimate parent and legal issuer for the senior secured notes. This reflects direct ownership of the subsidiaries and operating assets that generate the necessary cash flow to meet obligations and the expected lack of affiliated transactions, off-balance sheet obligations, or money pools.



With the operating subsidiaries generating the necessary cash flows to meet obligations, there is some reliance on affiliates; however, in KBRA's view, Corning Energy is positioned to manage obligations across its subsidiaries. Furthermore, each operating subsidiary has limitations on the amount of debt they can maintain. The subsidiaries are subject to debt caps of $2 million in the case of Pike and Leatherstocking and $5 million for Corning Gas. With these limitations in place, KBRA scores the company's reliance on affiliates/position in the group as Average.

Corning Energy's management team consists of industry professionals that have been with the company for a long duration. Additionally, KBRA believes that the regulatory oversight of the utilities industry further reduces governance risk through a high level of oversight, required annual rate case filings, and limitations on financial policymaking. KBRA scores the company's guarantees or subsidies as Average.

ESG Management

KBRA typically analyzes environmental, social, and governance (ESG) factors through the lens of how management teams plan for and manage relevant ESG risks and opportunities. More information on KBRA's approach to ESG risk management in corporate ratings can be found here. Over the medium term, corporate issuers will need to prioritize ESG risk management and disclosure with the likelihood of expansions in ESG-related regulation and rising investor focus on ESG issues.

KBRA analyzes many sector- and issuer-specific ESG issues but our analysis is often anchored around three core topics: climate change, with particular focus on greenhouse gas emissions; stakeholder preferences; and cybersecurity. Under environmental, as the effects of climate change evolve and become more severe, issuers are increasingly facing an emerging array of challenges and potential opportunities that can influence financial assets, operations, and capital planning. Under social, the effects of stakeholder preferences on ESG issues can impact the demand for an issuer's product and services, the strength of its global reputation and branding, its relationship with employees, consumers, regulators, and lawmakers, and, importantly, its cost of and access to capital. Under governance, as issuers continue to become more reliant on technology, cybersecurity planning and information management are necessary for most issuers, regardless of size and industry.

Environmental

KBRA anticipates that the global shift towards reducing emissions will pressure regulators and government agencies to find cost-effective solutions to reduce greenhouse gas (GHG) emissions. As a utility engaged in the distribution of natural gas, Corning Energy's operations are likely to be impacted by these regulatory efforts.

Through the Climate Leadership and Community Protection Act (CLCPA), New York created greenhouse gas emissions targets to reduce economywide emissions by 40% by 2030 and no less than 85% by 2050 from 1990 levels. The state has been proactive in initiating follow-up legislation to achieve the outlined targets. In Pennsylvania, the regulators and state are more in favor of the natural gas industry and its expansion, with support for the continuation of drilling of new natural gas wells and with natural gas utilities being approved for significant investments in their infrastructure.

Social

Corning Energy has a well-established presence in the city of Corning and long-standing relationships with the local communities, customers, regulators, and other key stakeholders in the areas it operates in.

Governance

Corning Energy benefits from an experienced management team that have been in the industry and with the company for a significant period of time. The company's private sponsor, Argo Infrastructure, has a limited track record of governance, having acquired the company recently in 2022. However, Argo Infrastructure is experienced in investing in the energy and infrastructure sectors with no major reported issued so far.

Within the regulated utilities industry, the regulators are aware of the sensitive nature of customer information and the increasing risk that cybersecurity attacks pose. The NYPSC has set minimum standards that all utility companies in the region must adhere to. The requirements include utility companies signing a date security agreement (DSA) to govern the exchange of customer information electronically. The PAPUC publishes guidelines for its utility companies, outlining the best practices for cybersecurity which provides methods for proactive prevention and steps to take should an attack occur.

Financial Risk

KBRA formed its view on the financial risk profile of Corning Energy based on a view of financial results, presentations, regulatory filings, and management projections. KBRA was provided access to the management team as part of the process.

The financial risk score of 9.9 is based on pro forma LTM Q2 2024 financial data. The most recent LTM data was selected to represent the company's financial risk profile to reflect the new amount of debt in the capital structure and expected growth of the company on a go-forward basis. Corning Energy's financial risk profile is characterized by its limited corporate scale within the utilities sector, stable revenues, and a significant amount of financial leverage given the company's size and scale.

Determinants	Pro Forma LTM Q2 2024	Score
Sales		
Revenues (Mn)	$43.5	18
Profitability		
EBIT Margin	24.7%	6
Return on Average Assets	9.7%	3
Cash Flow		
Free Cash Flow/Debt	17.9%	6
Retained Cash Flow/Debt	47.6%	3
Capital Structure & Leverage		
Debt/EBITDA	4.5x	12
Debt/Book Capital	48.6%	9
Coverage		
EBIT/Interest	2.5x	15
EBITDA/Interest	3.9x	15
Financial Policy		
Unencumbered Assets/Total Assets	56.2%	12
Financial Risk Score		**9.90**

Size -10%

For a utility operating company, revenue is a good representation for size and market share because its revenue is composed of reimbursable costs and a margin approved by its regulators. These reimbursable costs are composed of the prudent costs that the company undertakes in order to reliably deliver gas and electric services within its service territory. Corning Energy generated revenue of $43.5 million as of LTM Q2 2024 across its various subsidiaries, reflecting its small size compared to other utilities with regulated operations in the U.S. However, the company has seen consistent, incremental growth in its rate bases across all its subsidiaries.

Profitability -20%

Corning Energy's profitability profile is defined by consistent, double-digit margins. The profitability profile is underpinned by the cost-of-service model used in the company's operations in regulated utilities, which sets stable regulated rates of return that the utility is allowed to achieve on its recovered costs. KBRA expects that Corning Energy's profitability profile will remain appropriate for the rating category.

Cash Flow Analysis -20%

Corning Energy has consistently generated positive cash flows, albeit small in amount as a result of the scale of its operations. As of LTM Q2 2024, the company generated $7 million of cash from operations with capital expenditures of $15 million. On an ongoing basis, capital expenditures are expected remain stable within the same range, as the company primarily focuses on maintenance requirements of its current operations instead of allocating capital to expansion initiatives. The company's capital expenditures are expected to receive favorable rate recovery treatment, increasing the total rate base for its subsidiaries and as a result the company's earned return.

Capital Structure & Leverage -20%

Corning Energy has averaged a debt/book capital of 43.2% and a debt/EBITDA of 4.7x over the last four years and has remained in compliance with its regulatory capital range of 65%. On a pro forma basis for the proposed senior notes, debt/EBITDA is expected to be 4.5x in line with the historical average, which is a significant amount of leverage given the company's size and scale.

Interest Coverage -20%

In KBRA's view, the company has an adequate ability to meet its debt service obligations. Corning Energy has adequate coverage metrics for a regulated utility, with EBIT and EBITDA covering its interest payments 2.5x and 3.9x, respectively. Overall, the company's coverage metrics are expected to remain consistent given the stable nature of the company's revenues and cash flows.

Financial Policy -10%

The quantitative metrics associated with financial policy reflect the choices that management makes regarding the company's financial structure, the use of cash and relative attractiveness of profitable reinvestments in the business versus the payout to investors. Financial policy is an indication of the firm's desired or intended financial position and performance, and management's policies and risk appetite. At its heart, financial policy can either be a contributor or impediment to access to outside capital.

Corning Energy's capital structure is subject to limitations imposed by its regulators. The company is required to maintain a maximum debt to total capitalization of 65% by regulators, which restricts the potential for cash leakage and is a credit positive. As of LTM Q2 2024, the company's total debt/book capital is 49%. Additionally, this limits the financial policy impacts of the company's private sponsor.

Additional Rating Determinants

Country Risk & Transfer and Convertibility Risk

Corning Energy's operations are entirely within the U.S. KBRA analyzed the country risk inherent in the issuer rating assigned herein and concluded that the country risk exposure is minimal.

The ratings described in this report are unpublished, confidential ratings that will not be published or otherwise made publicly available by KBRA. This report is provided with the understanding that the Issuer will maintain the existence and content of this report as confidential, and will not use these ratings to market any securities, except to disclose this report to a limited number of investors, each of which (A) is bound by appropriate confidentiality obligations and has a need to know such information, (B) is a sophisticated financial institution with experience in evaluating investments such as the debt instruments described in this report and has performed its own evaluation of the transaction structure and the underlying assets, and (C) will not be relying on the rating for its investment decision, but requested and will use the report to satisfy regulatory requirements, the conditions of internal investment authorizations, or for purposes supplemental to the foregoing. The ratings set forth in this report are subject to all of the terms and conditions set forth in KBRA's website, which any party receiving this report or the ratings described herein should review and understand.

Pennsylvania Public Utility Commission v. Pike County Light & Power Company- Electric;
Docket No. R-2024-3052359

PIKE COUNTY LIGHT & POWER COMPANY- ELECTRIC DIVISION'S RESPONSES TO OFFICE OF CONSUMER ADVOCATE'S INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 9

4. Referencing Pike Response to OCA Set 2, Question 11. Confirm or deny that the KBRA credit ratings assigned to CEC and its series A and B senior secured notes are comparable to the rating scales assigned by Standard & Poor's.

RESPONSE: The KBRA credit ratings assigned to CEC and its series A and B senior secured notes are comparable to rating scales assigned by Standard & Poor's.

PROVIDED BY: Charles Lenns, Senior Vice President & Chief Financial Officer

DATE: March 24, 2025

Pennsylvania Public Utility Commission v. Pike County Light & Power Company- Electric;
Docket No. R-2024-3052359

PIKE COUNTY LIGHT & POWER COMPANY- ELECTRIC DIVISION'S RESPONSES TO OFFICE OF CONSUMER ADVOCATE'S INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 6

6. Provide a list of fuel adjustment clauses, rate mechanisms, trackers and/or riders that the PUC allows the Company to employ to recover costs between general rate cases. Include relevant docket numbers and copies of the corresponding PUC decisions.

RESPONSE: The Company has the following rate mechanisms, trackers and/or riders that are allowed by the PUC to employe to recover costs between general rate cases:

Pike Gas:

A) Gas Cost Rate – The gas cost rate is applied to each CCF (100 cubic feet) of gas supplied in accordance with the tariff. Each gas cost rate is computed and applied to customers' bills for a one year period during the billing periods of November through October, however the rate may be revised on an interim basis subject to the approval of the Pennsylvania Public Utility Commission. The most recent gas cost rate filed and approved with the Commission went into effect on November 1, 2024, and is included in docket number M-2024-3050971. Refer to the "GCR Approval Letter – 10.21.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

B) State Tax Adjustment Surcharge – this surcharge is recomputed using the elements prescribed by the Commission whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number R-2024-3052657. Refer to the "STAS Gas Approval Letter – 1.02.25" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

C) Distribution System Improvement Charge ("DSIC") – this charge is applied to recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number M-2024-3052549. Refer to the "DSIC Gas Approval Letter – 12.19.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

Pike Electric:

A) Default Service Charge – this charge is used to recover all costs associated with purchasing energy, capacity and ancillary services incurred by the Company in providing electric power supply to default service customers. The default service plan was most recently re-approved

PIKE COUNTY LIGHT & POWER COMPANY- ELECTRIC DIVISION'S RESPONSES TO OFFICE OF CONSUMER ADVOCATE'S INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, SET 6

by the Commission in the recommended decision in docket number P-2023-3039927. Refer to the "Default Service Program Recommended Decision" attachment provided for details. This charge consists of the Market Price of Electric Supply and the Electric Supply Adjustment Charge, and are separately stated on customer bills. These charges are updated on a semi-annual basis and approved by the Commission prior to update. The most recent semi-annual update filed and approved with the Commission went into effect on December 1, 2024, and is included in docket number M-2024-3052190. Refer to the "DSC December 2024 Approval Letter – 11.22.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

B) <u>State Tax Adjustment Surcharge</u> – this surcharge is recomputed using the elements prescribed by the Commission whenever the Company experiences a material change in any of the taxes used in calculation of the surcharge. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number R-2024-3052656. Refer to the "STAS Electric Approval Letter – 1.02.25" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

C) <u>Distribution System Improvement Charge ("DSIC")</u> – this charge is applied to recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure. The most recent amount filed and approved with the Commission went into effect on January 1, 2025, and is included in docket number M-2024-3052547. Refer to the "DSIC Electric Approval Letter – 12.19.24" attachment provided for a copy of the secretarial letter from the Commission indicating approval.

PROVIDED BY: Matthew Lenns, Controller

DATE: March 3, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

<u>VERIFICATION</u>

I, Maureen L. Reno, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 2, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 3, 2025

Signature: Maureen L. Reno
Maureen L. Reno

Address: 19 Hope Hill Road,
Derry, New Hampshire 03038

OCA St. No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2024-3052359**
Pike County Light & Power Company (Electric)	**)**	

DIRECT TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 3, 2025

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

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

A. I am Managing Director of and a Senior Consultant with PCMG and Associates LLC (PCMG). PCMG is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Exhibit KRP-1 to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Exhibit KRP-1 also contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Hawaii Public Utilities Commission, the Illinois Commerce Commission, the Kansas Corporation Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the

Massachusetts Department of Public Utilities, the Missouri Public Service Commission, and the North Dakota Public Service Commission.

Q. PLEASE SUMMARIZE YOUR ELECTRIC AND GAS REGULATORY EXPERIENCE.

A. For most of my career I have performed analyses of and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Specifically regarding electric utilities, I have testified on: (a) integrated resource planning, (b) weather emergency response and recovery, (c) the restructuring of electric markets and unbundling of retail rates, (d) class cost of service and rate design, and (e) infrastructure-related expense and investment recovery mechanisms.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony responds to Pike County Light and Power (PCLP) Electric Division's proposed allocated class cost of service study, revenue allocations, and rate design in its general rate increase request before the Pennsylvania Public Utility Commission (Commission).

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below, I find that:

- There is no basis in theory, system design and operating practice, or empirical quantitative data to support PCLP's use of the minimum-size method to classify as customer-related any portion of its distribution costs in Accounts 364, 365, 366, 367 and 368 in its electric cost of service study (ECOSS), and I recommend that the Commission reject PCLP's ECOSS results as a guide for class revenue allocation in this proceeding;
- PCLP's ECOSS without minimum-size classification produces results that are consistent with the principle of cost causation, and I recommend that the Commission accept the results of the PCLP ECOSS <u>without</u> minimum-size classification as a guide for class revenue distribution;
- Revenue distribution to PCLP's customer classes guided by the ECOSS <u>without</u> minimum-size classification is just and reasonable;
- To provide residential customers with (1) an incentive to engage in conservation; (2) the ability to exercise control over a significant portion of their monthly electric distribution bill; and (3) to avoid deleterious impact on low-income customers, PCLP's residential customer charges should remain at their current levels.

B. COST ALLOCATION AND RATE DESIGN

Q. WHAT IS THE RELATIONSHIP BETWEEN COST ALLOCATION AND RATE DESIGN?

A. In regulatory theory and practice the relationship between cost allocation and rate design and the utility's recovery of its approved revenue requirement is conceptually simple. If a utility's costs of providing service are not accurately allocated to its rate classes and rate class costs are not accurately reflected in the rate classes' tariff billing charges, then the utility will either over or under recover its costs of service or revenue requirement. The less accurately the costs are reflected in the rate classes' tariff billing charges, the greater the utility's under or over recovery of its costs will be. Additionally, on a conceptual basis, a utility's costs should be allocated consistent with the principle of cost causation. Regarding electric utilities, the primary drivers of costs are (1) the number of customers served by the utility's production and delivery system, (2) customer demand on the system, and (3) the volume of electric energy delivered to customers.

In this proceeding, the revenue requirement, class costs and tariff rates at issue concern PCLP's electric retail distribution delivery systems serving customers in Pennsylvania. Consequently, the fundamental issue is whether PCLP's proposed customer class cost allocations, class revenue allocation and tariff rates (1) accurately reflect the customer costs and demand costs of its customers and (2) thus minimize the likelihood of either under or over recovery of PCLP's electric revenue requirement.

C. TARIFF RATE CLASSES AND RATE STRUCTURES

Q. WHAT TARIFF RATE CLASSES AND RATE STRUCTURES DOES PCLP PROPOSE?

A. PCLP proposes six tariff rate classes. PCLP's proposed base rate structures consist of four rate classes with a fixed monthly customer charge and a kilowatt-hour volumetric distribution charge; one of the four rate classes also has a kilowatt demand charge; and there are two lighting classes, both of which have multiple per fixture monthly charges.[1]

Q. ARE ALL SIX TARIFF RATE CLASSES INCLUDED IN THE CUSTOMER CLASSES USED IN PCLP'S ECOSS?

A. Yes, as shown in Table 1 below.

Table 1 – PCLP ECOSS Customer Classes and Tariff Rate Structures

Rate Class	Customer Charge	Delivery Charge	Demand Charge	Monthly Fixture Charge
SC1 Residential	X	X		
SC1 Residential Space/Water Heating	X	X		
SC2-S Secondary	X	X	X	
SC2-P Primary	X	X		
SC3 Municipal Lighting				X
SC4 Private Area Lighting				X

[1] Exhibit E-8, pages 3-10.

Q. DO YOU HAVE ANY CRITICISMS OF PCLP'S PROPOSED RATE CLASSES AND RATE STRUCTURES?

A. I do not have any criticisms of PCLP's proposed tariff rate classes and rate structures, but as discussed below, I have concerns about PCLP's rate design for residential customers in so far as PCLP proposes to increase the residential customer charge.

D. ELECTRIC COST OF SERVICE STUDY

Q. HAVE YOU EXAMINED PCLP'S ECOSS?

A. Yes. PCLP's ECOSS (Exhibit E-6) is based on an historic year consisting of the 12 months ending September 30, 2024. The ECOSS consists of a single excel workbook with three substantive tabs: (1) Cost of Service, (2) Functions, and (3) Unbundled.[2] The ECOSS follows the standard four-step procedure of (1) functionalization of costs, (2) classification of functionalized costs as demand-related, commodity-related or customer-related, (3) direct assignment or allocation to classes of the classified functionalized costs using demand, commodity and customer allocators, and (4) calculation of class rates of return and relative rates of return under present rates. The ECOSS uses the minimum-size method[3] to classify the distribution facilities in plant accounts 364-368 as consisting of both a customer-related component and a demand-related component, with the customer component allocated to classes on number of customers and the demand component allocated to classes on demand.[4]

---

[2] Pike ECOS 01-09-25P.xlsx; Exhibit E-6, Schedules PMN-2-E TO PMN-6-E.

[3] See 2013 Pike Electric Minimum System Calculations for 365 & 367.xlsx and 2013 Minimum System for Transformers.xlsx.

[4] Direct Testimony of Paul M. Normand, page 10 line 9 to page 12 line 1; Exhibit E-6, Schedule PMN-4-E, page 2 LINES 12-34.

Q. WHAT FACILITIES ARE CONTAINED IN PCLP'S DISTRIBUTION PLANT ACCOUNTS 364-368?

A. PCLP's plant accounts 364-368 contain costs associated with the overhead and underground wires, supporting structures, and line transformers that connect the distribution system to meters and other installations at customer premises. PCLP witness Normand also refers to plant in these accounts as low tension or secondary line facilities.[5]

Q. WHAT IS THE MINIMUM-SIZE SYSTEM METHOD OF CLASSIFICATION AND ALLOCATION?

A. It is one of two methods for classification of distribution costs that are described in the NARUC Electric Utility Cost Allocation Manual: (1) the minimum-size method,[6] which PCLP uses; and (2) the minimum-intercept method, which PCLP does not use.[7] The objective of the minimum-size method is to classify distribution plant and associated operating costs to determine the cost driver of each rate base item and operating cost — namely demand or customers — and allocate the plant and operating costs purportedly consistent with the principle of cost causation. PCLP applies the minimum-size method to plant accounts 364, 365, 366, 367, and 368.

The minimum-size system method assumes that a minimum-size distribution system can be built to serve the minimum loading requirements of the system's customers.[8] This assumption is addressed below. The NARUC Manual describes how to calculate the

[5] Normand Direct, page 10 line 11 to page line 11.
[6] National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (NARUC Manual) 1992, pages 90-92.
[7] NARUC Manual, pages 92-94.
[8] NARUC Manual, page 90.

minimum-size and cost of a given distribution system.[9] The calculated minimum-size system costs for each distribution plant type are classified as customer-related and allocated to classes based on the number of customers. The remaining cost of each plant type is classified as demand-related and allocated based on demand.

Q. HAVE YOU IDENTIFIED ANY COST CLASSIFICATION ERRORS IN THE ECOSS?

A. Yes. In the classification step, as I noted above, PCLP uses the minimum-size system method to classify portions of the distribution system as both demand-related and customer-related. Classifying any portion of these distribution accounts as customer-related contravenes the principle of cost causation, which is the guiding principle of all regulated utility cost of service studies.[10]

Q. WHAT SUPPORT DOES PCLP OFFER FOR ITS USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION?

A. None. To investigate what support there might be for PCLP's use of the minimum-size method of classification of distribution facilities I requested in a data request PCLP's planning, design, and operating standards and procedures applicable to the distribution facilities recorded in plant accounts 364-368.[11]

[9] NARUC Manual, pages 91-92.
[10] NARUC Manual, pages 12-13.
[11] OCA Interrogatory 8.4.

Q. WHY DID YOU REQUEST PCLP'S PLANNING, DESIGN, AND OPERATING STANDARDS AND PROCEDURES FOR PLANT ACCOUNTS 364-368?

A. PCLP's foundational assumption in using the minimum-size method is that the number of customers on the distribution system causes at least a portion of the costs recorded in plant accounts 364-368. With PCLP's planning, design, and operating standards and procedures for plant accounts 364-368, it is possible to confirm or disconfirm PCLP's assumption that customers are the cause of a portion of the costs of the facilities in its plant accounts 364-368. If the number of customers is not a factor in the planning, design, and operation of PCLP's account 364-368 distribution assets, then there is in fact no support for PCLP's application of minimum-size classification of the costs in plant accounts 364-368. Based on my inspection of PCLP's response to OCA IR-8-4, the response clearly demonstrates that the number of customers on PCLP distribution system plays no role in the design, planning, and operation of PCLP's plant recorded in plant accounts 364-368. Therefore, the number of customers on PCLP's system is not a cause of any portion of the facilities the costs of which are recorded in accounts 364-368.

Q. WHAT IS YOUR RECOMMENDATION RELATING TO PCLP'S USE OF THE MINIMUM-SIZE SYSTEM METHOD IN THE ECOSS?

A. As I explain below, I recommend that PCLP's use of the minimum-size classification method to classify the distribution costs in Accounts 364-368 as customer-related costs be rejected. This is because PCLP has not provided any evidence that customers, as opposed to demand for energy, are in fact the cause or driver of any portion of its distribution costs associated with the overhead and underground wires, supporting structures, and line transformers that connect the distribution system to meters and other installations at customer premises.

Q. IS THE MINIMUM-SIZE METHOD COMMONLY USED BY ELECTRIC UTILITIES?

A. At the time that the NARUC Manual was first published in 1992, the minimum-size method was commonly used by electric utilities in North America, hence its inclusion in the NARUC Manual, which has not been revised since 1992. Today, however, it is less used by major electric utilities. For example, none of the Exelon electric operations use the minimum-size method.

Q. IS THE COMMON USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION RELEVANT TO DETERMINING THE PROPER CLASSIFICATION OF DISTRIBUTION SYSTEM COSTS FOR PCLP IN THIS PROCEEDING?

A. No. Selection of the appropriate classification method(s) for a utility's electric distribution system for costing purposes depends on the specific design and operating characteristics of the distribution system consistent with the principle of cost causation, not on whether other utilities in other jurisdictions use a specific classification method nor on whether the utility has used a specific classification method in prior proceedings. Regulatory costing is a forward-looking exercise. The only relevant question is whether the classification method reflects the cost causation inherent in the planning, design, and operation of PCLP's distribution system. Again, as I explain below, the minimum-size method of classification does not reflect the planning, design, and operation of PCLP's distribution system.

Q. WHAT DISTRIBUTION COSTS ARE CAUSED BY CUSTOMERS?

A. Principles of Public Utility Rates (Bonbright), the canonical regulatory ratemaking text, defines electric distribution customer costs as "those operating and capital costs found to vary with the number of customers."[12] Bonbright points out that the distribution system costs that satisfy this definition are "the minimum service, metering, accounting, etc. costs of connecting another customer or the savings in costs of not connecting the customer," namely, the costs of the customer equipment recorded in plant accounts 369-371. Thus, this is not an arbitrary or theory-driven definition, but rather a definition based on a practical and empirically verifiable cause – namely, the act of adding a customer to or dropping a customer from the distribution system.

Q. DOES BONBRIGHT ADDRESS THE NARUC MANUAL'S MINIMUM-SIZE AND MINIMUM-INTERCEPT CLASSIFICATION OF DISTRIBUTION COSTS?

A. Yes. Bonbright describes both methods as assuming "hypothetical" and "phantom" distribution systems that rest on the erroneous assumption that "since [the minimum system costs] vary directly with the area of the distribution system (or else with the lengths of the lines, depending on the type of distribution system), they therefore vary directly with the number of customers," which "makes no allowance for the density factor (customers per linear mile or square mile)."[13] In simpler terms, the costs of the distribution lines and line transformers for a given system will be the same if the system serves X number of customers in an area of a given size or 2X number of customers in an area of identical size. Electric utilities design the components of their distribution system that are upstream of

---

[12] Principles of Public Utility Rates 1988 (Bonbright), page 490; NARUC Electric Manual, page 90.
[13] Bonbright, page 491.

the equipment required to connect a customer to the system to meet the aggregate peak demand of the customers on the system. Otherwise, the utility would not be able to deliver firm service to customers at system peak demand.

Regarding the minimum-intercept system, Bonbright adds that a systematic regression analysis found no statistical association between distribution costs and number of customers.[14] I note that I have never seen an analysis of empirical utility data that demonstrates either that distribution system costs vary with the number of customers on a distribution system or that there is a statistically significant correlation between distribution system costs and the number of customers.

Q. DOES PCLP DESIGN AND OPERATE ITS DISTRIBUTION SYSTEM TO MEET PEAK LOAD?

A. Yes. Every regulated utility that offers firm electric service to its customers does and must plan, design, and operate the components of its distribution system that are upstream of the customer equipment to meet its system's peak load. Otherwise, the utility would not be able to provide firm service to consumers at peak load.

Q. HOW DOES THE NARUC MANUAL DEFINE DISTRIBUTION CUSTOMER COSTS?

A. Consistent with Bonbright, the NARUC Manual defines "the customer component of distribution facilities [as] that portion of costs which varies with the number of customers." The NARUC Manual then immediately follows, however, with a *non-sequitur*, that is, the unsupported assertion that "[t]hus, the number of poles, conductors, transformers, services

[14] Bonbright, page 491.

and meters are directly related to the number of customers on the utility's system" (emphasis added).[15] In this regard, the NARUC Manual is simply wrong. Note that this is exactly the same assumption debunked by Bonbright above. The number of customers directly causes the amount and costs of the customer equipment, not the amount and costs of the distribution system's overhead and underground wires, supporting structures, and line transformers. The amounts and costs of the facilities recorded in distribution overhead and underground lines and line transformers are not "directly related to the number of customers." They are rather directly related to the aggregate peak load or demand of customers.

Q. DOES THE NARUC MANUAL PROVIDE ANY EXPLANATION OR DEMONSTRATION THAT A PORTION OF DISTRIBUTION COSTS VARIES WITH OR IS CAUSED BY THE NUMBER OF CUSTOMERS?

A. No. As I explained above, the NARUC Manual simply assumes without explanation or demonstration that the minimum-size method and the minimum-intercept method identify and quantify a portion of distribution costs that varies with or is caused by the number of customers.

Q. HAS PCLP PROVIDED ANY EMPIRICAL QUANTITATIVE EVIDENCE THAT ANY PORTION OF ITS DISTRIBUTION SYSTEM COSTS VARY WITH THE NUMBER OF CUSTOMERS?

A. No. Nor has PCLP provided any evidence to support (1) its reliance on the NARUC Manual's minimum-size classification, contrary to Bonbright's demonstration that

[15] NARUC Electric Manual, page 90.

minimum-size classification contradicts the principle of cost causation which underlies all utility cost studies; and (2) its assumption that customers are a cost factor that causes some portion of the costs of assets recorded in its plant accounts 364-368.

Q. WHAT DO YOU CONCLUDE REGARDING PCLP'S USE OF THE MINIMUM-SIZE SYSTEM METHOD TO CLASSIFY A PORTION OF ITS DISTRIBUTION COSTS AS CUSTOMER-RELATED AND ALLOCATE THOSE COSTS TO CUSTOMER CLASSES BASED ON THE NUMBER OF CUSTOMERS?

A. As explained above, there is no basis in theory, system design and operation practice, or empirical quantitative data to support PCLP's use of the minimum-size system method to classify as customer-related any portion of its distribution costs. PCLP's distribution costs do not vary with the number of customers – additions and deletions of customers do not cause those costs to increase or decrease. Thus, I conclude that the Company's distribution costs in plant accounts 364-368 are properly classified as 100 percent demand-related and properly allocated to classes using PCLP's demand allocation factors.

Q. WHAT IS THE IMPACT ON PCLP'S ECOSS CUSTOMER CLASSES OF ELIMINATING THE MINIMUM-SIZE CLASSIFICATION OF PCLP'S DISTRIBUTION OVERHEAD AND UNDERGROUND LINES AND LINE TRANSFORMER COSTS?

A. As a general matter, minimum-size classification of distribution costs increases the costs allocated to rate classes with large numbers of customers (i.e., the residential rate classes) and decreases costs allocated to rate classes with small numbers of customers. Because the number of customers in a rate class is not a cause or driver of distribution costs, minimum-size classification over allocates costs to rate classes with large numbers of customers (i.e., the residential rate classes) and under allocates costs to rate classes with small numbers of customers The effect of this misallocation of costs can be seen by comparing the class rates of return and relative rates of return[16] calculated by PCLP's ECOSS to those calculated by eliminating minimum-size classification from PCLP's ECOSS.

Q. WHAT IS THE PURPOSE OF THE RELATIVE RATE OF RETURN METRIC?

A. Relative rate of return is the commonly used metric by which fair cost apportionment is measured and evaluated. PCLP's ECOSS calculates the overall rate of return and relative rate or return for PCLP's electric system and the rates of return and relative rates of return for each class. A class relative rate of return of 1.00 indicates that the class is earning the overall rate of return. A class relative rate of return less than 1.00 indicates that the class is underearning or under recovering its cost of service, i.e., the revenue generated by rates is not covering the full cost of service to the class. A class relative rate of return greater than 1.00 indicates that the class is overearning or over recovering its cost of service, i.e., the revenue generated by rates is more than covering the full cost of service to the class. Relative rates of return are used as a guide for allocating the revenue increase to classes so as to move each class closer to full recovery. Table 2 below compares the class rates of return and relative rates of return under PCLP's ECOSS with and without minimum-size classification.

[16] PCLP's ECOSS refers to relative rate of return as "Distribution Index Rate of Return," see Exhibit E-6, Schedules PMN-2-E, line 31.

Table 2 - PCLP Rates of Return (ROR) and Relative Rates of Return (RROR) by Customer Class Under Current Rates – With and Without Minimum-Size Classification				
Customer Class	**With Minimum System**[17]		**Without Minimum System**[18]	
	ROR	**RROR**	**ROR**	**RROR**
SC1 Residential	3.58%	0.57	5.02%	0.80
SC1 Residential Space/Water Heating	5.97%	0.95	6.16%	0.98
SC2-S Secondary	9.98%	1.58	6.84%	1.08
SC2-P Primary	9.90%	1.57	9.90%	1.57
SC3 Municipal Lighting	2.71%	0.43	10.15%	1.61
SC4 Private Area Lighting	0.47%	0.07	5.04%	0.80
Total	6.30%	1.00	6.30%	1.00

The PCLP ECOSS without minimum-size classification, which allocates distribution costs on demand, results in higher rates of return and relative rates of return for the SC1, SC3 and SC4 customer classes, lower rate of return and relative rate of return for the SC2-S customer class, and the same rate of return and relative rate of return for the SC2-P customer class. The relative rates of return of the SC2-S, SC2-P and SC3 customer classes are higher than 1.00 indicating that these classes are over earning under PCLP's current rates; minimally for SC2-s and substantially for SC2-P and SC3. The relative rates of return for the SC1 R, SC1 RS/W and SC4 customer classes are lower than 1.00, an indication that these classes are under earning under PCLP's current rates; minimally for SC1 RS/W and moderately for SC1 and SC4.

[17] Exhibit E-6, Schedule PMN-3-E, page 1 lines 7 and 8,
[18] Exhibit KRP-2, lines 7 and 8.

Q. HAVE YOU IDENTIFIED ANY ERRORS IN THE COST ALLOCATORS IN PCLP'S ECOSS?

A. No.

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING PCLP'S ECOSS?

A. I conclude that PCLP's ECOSS produces results inconsistent with the principle of cost causation, because contrary to the minimum-size method's assumption, the number of customers is neither a cause nor a driver of distribution costs. I also conclude that PCLP's ECOSS without minimum-size classification produces results consistent with the principle of cost causation, because demand is both the cause and the driver of PCLP's electric distribution system costs. I recommend that the Commission adopt the ECOSS without minimum-size classification as a guide for determining PCLP's class revenue allocation and tariff rates.

E. PCLP'S CUSTOMER CLASS REVENUE DISTRIBUTIONS

Q. HAVE YOU EXAMINED PCLP'S PROPOSED CLASS REVENUE DISTRIBUTION?

A. Yes. The testimony[19] and exhibits[20] of witness Normand also present PCLP's class rate design. Regarding class revenue responsibility distribution, Witness Normand states that "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

[19] Normand Direct, page 17 line 18 to page 19 line 18.
[20] Exhibit 7, page 1; Exhibit 6, Schedule PMN-3-E.

service 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"[21] Table 3 compares the class revenue distribution under current rates and the proposed revenue distribution.

Table 3 - PCLP Current Revenue Distribution and Proposed Revenue Distribution[22]			
Customer Class	**Current**	**Proposed**	**Percent Increase**
SC-1 Residential	2,951,615	3,896,239	32.00%
SC-1 Residential Space/Water Heating	665,104	879,184	32.19%
SC-2 Secondary	3,040,902	3,833,137	26.05%
SC-2 Primary	541,306	682,313	26.05%
SC-3 Municipal Lighting	112,628	148,711	32.04%
SC-4 Private Area Lighting	49,527	65,395	32.04%
Total	7,361,084	9,504,985	29.12%

Q. WHAT PROCEDURE DOES WITNESS NORMAND APPLY TO PCLP'S ECOSS RESULTS TO DERIVE THE PCLP PROPOSED REVENUE DISTRIBUTION?

A. Witness Normand follows a two-step procedure. First, he calculates a +10% percent tolerance band around the 6.30% ECOSS rate of return, i.e., 5.57% to 6.93%, and states that by this measure the classes with rates of return above 6.93% (SC2-S and SC2-P) are subsidizing the classes with rates of return below 5.57% (SC1, SC3 and SC4).[23] See Table 4 below.

[21] Normand Direct, page 18 lines 5-9.
[22] Exhibit E-6, Schedule PMN-3-E, page 1 lines 9, 29 and 32.
[23] Normand Direct, page 16 line 4 to page 17 line 2.

Q. WHAT IS YOUR OPINION REGARDING THIS FIRST STEP?

A. I do not oppose the principle of a tolerance band and have endorsed and used it in rate proceedings in Maryland but note that it is usually articulated as ±10% of the relative rate of return of 1.00., i.e., 0.90 to 1.10. In any event, whichever tolerance band measure is used here the result is the same. See Table 4 below.

Q. WHAT IS WITNESS NORMAND'S SECOND STEP?

A. Witness Normand's second step is to limit the revenue increase of the subsidized classes from the first step to 110% of overall increase, namely, 32% (110% x 29.1% = 32%).[24] See Table 3 above. The actual calculations shown in Exhibit E-8[25] are considerably more complicated than as described in witness Normand's testimony, which accounts for the discrepancy between the testimony 32.0% and the actual revenue increase percentages for SC1, SC3 and SC4 classes seen in Table 3.

Q. DO YOU AGREE WITH THE SECOND STEP?

A. No. I disagree with the 110% of the increase of the overall increase. Witness Normand presents no evidence supporting the 110% and as I note below, it results in minimal movement towards relative rates of return of 1.00 for the classes. The relative rates of return for the classes are not much different than they would be if he simply applied the overall increase to the revenue distributions under current rates.

Q. HOW DO PCLP'S PROPOSED CLASS REVENUE DISTRIBUTIONS IMPACT CLASS RATES OF RETURN?

[24] Normand Direct, page 18 line 13 to page 17 line 12; Exhibit E-8, pages 1 and 2.

[25] Exhibit E-8, pages 1 and 2, lines 2-11.

A. Table 4 below shows the impact of PCLP's proposed revenue distributions on class rates of return and relative rates of return for PCLP's customer classes. Examination of the relative rate of return results in Table 4, reveals that for most of PCLP's customer classes the proposed class revenue requirement represents minimal movement towards relative rates of return of 1.00, leaving most classes either heavily overearning or heavily underearning measured against the relative rates of return from PCLP's minimum-size ECOSS.

Table 4 – PCLP Rates of Return (ROR) and Relative Rates of Return (RROR) by Customer Class – COSS Compared to PCLP Proposed Class Revenue Distribution				
Customer Class	**PCLP COSS With Minimum System**[26]		**PCLP Class Revenue Distribution**[27]	
	ROR	**RROR**	**ROR**	**RROR**
SC-1 Residential	3.58%	0.57	4.71%	0. 56
SC-1 Residential Space/Water Heating	5.97%	0.95	8.63%	1.03
SC-2 Secondary	9.98%	1.58	13.39%	1.60
SC-2 Primary	9.90%	1.57	13.79%	1.65
SC-3 Municipal Lighting	2.71%	0.43	1.02%	0.12
SC-4 Private Area Lighting	0.47%	0.07	-2.07%	-0.25
Total	6.30%	1.00	8.37%	1.00

Q. DO YOU AGREE WITH PCLP'S PROPOSED CLASS REVENUE DISTRIBUTIONS?

A. No, they are based on PCLP's minimum-size ECOSS which, as I explained above, is not consistent with or reflective of actual cost causation. Second, they do not reflect the overall revenue requirement and rate of return presented in OCA witness Rogers' testimony.[28]

[26] Exhibit E-6, Schedule PMN-2-E, page 1 lines 30 and 31.
[27] Exhibit E-6, Schedule PMN-3-E, page 1 lines 33 and 34.
[28] Direct Testimony of Jennifer Rogers, Schedule JLR-1.

Q. HAVE YOU CALCULATED CLASS REVENUE REQUIREMENTS BASED ON PCLP'S ECOSS WITHOUT MINIMUM-SIZE CLASSIFICATION?

A. Yes. I have developed the OCA recommended class revenue increase distributions based on the relative rates of return of the ECOSS without minimum size. The resulting relative rates of return and rates of return are shown in Table 5 below.

Table 5 - Class Rates of Return (ROR) and Relative Rates of Return (RROR) by Customer Class – ECOSS without minimum-size compared to OCA Recommended				
Customer Class	**Without Minimum System[29]**		**OCA Recommended[30]**	
	ROR	**RROR**	**ROR**	**RROR**
SC1 Residential	5.02%	0.80	6.66%	0.80
SC1 Residential Space/Water Heating	6.16%	0.98	8.18%	0.98
SC2-S Secondary	6.84%	1.08	9.08%	1.08
SC2-P Primary	9.90%	1.57	13.14%	1.57
SC3 Municipal Lighting	10.15%	1.61	13.48%	1.61
SC4 Private Area Lighting	5.04%	0.80	6.69%	0.80
Total	6.30%	1.00	8.37%	1.00

Table 6 below shows the impact of OCA's recommended revenue distributions on class rates of return and relative rates of return for PCLP's customer classes.

[29] Exhibit KRP-2, lines 7 and 8,
[30] KRP-2, lines 37 and 38.

Table 6 - PCLP Current Revenue Distribution and OCA Recommended Revenue Distribution[31]

Customer Class	Current	Proposed	Percent Increase	Class Percent Distribution
SC-1 Residential	2,951,615	3,779,679	28.05%	39.77%
SC-1 Residential Space/Water Heating	665,104	853,112	28,27%	8.98%
SC-2 Secondary	3,040,902	3,984,668	31.04%	41.92%
SC-2 Primary	541,306	667,865	23.38%	7.03%
SC-3 Municipal Lighting	112,628	151,525	34.54%	1.59%
SC-4 Private Area Lighting	49,527	68136	37.57%	0.72%
Total	7,361,084	9,504,985	29.12%	100.00%

[31] Exhibit KRP-2, lines 9, 43, 45 and 44

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING PCLP'S CLASS REVENUE INCREASE DISTRIBUTIONS?

A. I conclude that PCLP's proposed class revenue distributions should be rejected because they are based on the ECOSS that is inconsistent with the principle of cost causation. I recommend that the Commission accept the non-minimum system ECOSS's class revenue distributions because they are based on the ECOSS without minimum-size that is with the principle of cost causation.

Q. DO YOU HAVE A SCALE BACK PROPOSAL?

A. Yes. I recommend that, if the Commission does not adopt the PCLP's proposed overall revenue increase, for whatever revenue increase is ultimately adopted by the Commission, the revenue increase be scaled back and allocated based on the class revenue distribution percentages in Table 6.

Q. HAVE YOU CALCULATED CUSTOMER CLASS REVENUE DISTRIBUTIONS CONSISTENT WITH OCA WITNESS ROGER'S RECOMMENDED REVENUE REQUIREMENT?

A. Yes. I have applied the class revenue distribution percentages from Table 6 to witness Normand's current revenues plus witness Rogers' recommended revenue increase of $1,334,200.[32] The results are shown in Table 7 below.

[32] Rogers Direct, Schedule JLR-1.

Table 7 - PCLP Current Revenue Distribution and OCA Recommended Revenue Distribution Scaled Back per OCA recommended Revenue Requirement[33]				
Customer Class	**Current**	**Recommended**	**Percent Increase**	**Class Percent Distribution**
SC-1 Residential	2,951,615	3,482,226	17.98%	39.77%
SC-1 Residential Space/Water Heating	665,104	784,915	18.01%	8.98%
SC-2 Secondary	3,040,902	3,600,199	18.39%	41.92%
SC-2 Primary	541,306	635,100	17.33%	7.03%
SC-3 Municipal Lighting	112,628	133,842	18.84%	1.59%
SC-4 Private Area Lighting	49,527	59,133	19.40%	0.72%
Total	7,361,084	8,695,415	18.13%	100.00%

F. CLASS TARIFF RATES

Q. WHAT ARE PCLP'S PROPOSED TARIFF RATES?

A. PCLP's proposed tariff rates for each customer class are shown in Exhibit E-8, pages 3-10[34] The tariff rates are based on the PCLP rate district class revenue distributions in Table 4 above.

Q. DO YOU AGREE WITH PCLP'S PROPOSED RATE DISTRICT CLASS TARIFF RATES?

A. No. The tariff rates for all PCLP's rate classes should be decreased consistent with the OCA class revenue distributions in Table 7.

[33] Exhibit KRP-3.
[34] Exhibit E-8, pages 3-10.

Q. WHAT SPECIFIC RATES DOES PCLP PROPOSE FOR RESIDENTIAL CUSTOMERS?

A. As shown in Table 8 below, PCLP proposes to increase Residential customer charges by 22.7% to $10.80 with the remainder of the revenue increase to be recovered through the volumetric kWh distribution charge.

Table 8 – Comparison of PCLP Current and Proposed Residential Customer Charges[35]

Customer Class	Current Customer Charge	Proposed Customer Charge	Percent Increase
SC-1 Residential	$8.80	$10.80	22.7%
SC-1 Residential Space/Water Heating	$8.80	$10.80	22.7%

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER CHARGES?

A. I recommend that the residential customer charges be left at their current level.

Q. WHY DO RECOMMEND THAT THE RESIDENTIAL CUSTOMER CHARGES REMAIN AT THEIR CURRENT LEVEL?

A. As shown in Table 8, PCLP's proposed residential customer charges represent a 22.7% increase over the current charges, which would represent significant and unacceptable rate shock to no discernible ratemaking benefit. A fixed monthly customer charge sends no real actionable price signal to residential customers. No residential customer chooses either to take service or to take a given amount of service based on the customer charge. Thus, the ratemaking principle of efficiency provides no basis to set the customer charge at one

[35] Exhibit E-8, page 3.

level or another. On the other hand, if the residential customer charge is left unchanged, the increased revenue approved in this proceeding will be recovered through the volumetric distribution charge, where it will definitely send a real actionable price signal regarding conservation and customers' control over their monthly bills. Placing all of the increase in the volumetric distribution charge will provide residential customers with both (1) an increased incentive to engage in conservation and (2) the ability to exercise control over a larger portion of their monthly electric distribution bill. For all these reasons I recommend that the residential customer charges remain at their current level as shown in Table 8 above.

Q. **HAS THE COMMISSION RECENTLY ISSUED ANY DECISIONS AS TO INCREASED CUSTOMER CHARGES**?

A. Yes. Columbia proposed an increase in its existing monthly customer charge in Docket No. R-2020-3018835. In that proceeding the Administrative Law Judge (ALJ) found that Columbia's proposed increase in the residential customer charge was contrary to the Commission's goal of encouraging customers to conserve energy and denied the Company's requested increase in the monthly customer charge. The Commission adopted the ALJ's decision regarding the residential customer charge.[36]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by PCLP.

[36] *Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, Order at 264-65 (Feb. 19, 2021).

KARL RICHARD PAVLOVIC, Ph.D.

Education

Purdue University – MA and Ph.D. in Philosophy

Karl-Ruprecht Universität, Heidelberg, Germany – graduate study

Yale University – BA in Philosophy

Positions

Senior Consultant – PCMG and Associates	2015-Present
Senior Consultant – Snavely King Majoros and Associates	2010-2014
Director – FTI Consulting	2008-2010
President – DOXA, Inc	1994-2008
Partner – Snavely King and Associates	1983-1994
Assistant Professor – University of Florida-Gainesville	1978-1983

Professional Experience

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation. Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, effects of mergers, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, electric and gas reliability, and the performance of energy efficiency, renewable energy, and peak reduction programs.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; technical representation of the District of Columbia People's Counsel on the DC PSC's Pepco Productivity Improvement Working Group and various PJM working groups; impact evaluation study of pilot energy efficiency and renewable energy programs in the District of Columbia; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. With 33 years' experience as a consultant and expert witness, Dr. Pavlovic has in-depth knowledge of commercial and industrial operations in the energy, transportation, and telecommunications industries and is familiar with a wide range of experimental and investigative methods in science and engineering.

Regulatory Projects and Appearances

1. In re: the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota (2024) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-20-441

2. In re: 2023 Gas System Enhancement Program Plan Filings for the Commonwealth's Natural Gas Distribution Companies (2024) - (Appearance: cost and project compliance with tariff on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket Nos. D.P.U. 23-GSEP-01 to 23-GSEP-06

3. In re: the Application of Northern States Power Company for Advance Determination of Prudence – 345kV Big Stone to Sherburne (2024) - (Appearance: need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-23-329

4. Pennsylvania Office of Consumer Advocate: Monitor, Review and Report on Electric and Natural Gas Filings to the FERC (2024)
   Federal Energy Regulatory Agency Dockets

5. In re: Petition of Veolia Water New Jersey, Inc. for an Increase in Rates for Water Service and Other Tariff Changes (2023) - (Appearance: cost of service and rate design on behalf of the New Jersey Rate Counsel)
   NJ BPU Docket No. WR23110790

6. In re: the Application of Northern States Power Company for Advance Determination of Prudence – Brookings County to Lyon County and Helena to Hampton 345 kV Second Circuit (2023) - (Appearance: need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-23-295

7. In re: the Application of Northern States Power Company for Advance Determination of Prudence - Sherburne County 345 kV Transmission Line (2023) - (Appearance: need, necessity and conformance with North Dakota Statutes and Regulation on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-23-142

8. In re: Petition of Middlesex Water Company for an Increase in Rates for Water Service and Other Tariff Changes (2023) - (Appearance: cost of service and rate design on behalf of the Township of East Brunswick, New Jersey)
   NJ BPU Docket No. WR23050292

PCMG and Associates LLC

9. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2022 Gas System Enhancement Plan Reconciliation Filing (2023) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 23-GREC-06

10. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2022 Gas System Enhancement Plan Reconciliation Filing (2023) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 23-GREC-05

11. In re: Petition of Berkshire Gas Company for Approval of its 2022 Gas System Enhancement Plan Reconciliation Filing (2023) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 23-GREC-02

12. In re: Pittsburgh Water and Sewer Authority General Base Rate Increase Filing (2023) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2023-3039920 et al

13. In re: UGI Electric Company General Base Rate Increase Filing (2023) – (Appearance: electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2022-3037368

14. In re: Application of Hawaii Water Service Company, Inc. for Approval of a General Rate Increase for its Pukalani Wastewater Diviion and Certain Tariff Changes (2023) – (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2022-0186

15. In re: Application of Lanai Water Company, Inc. for Review and Approval of Rate Increases; Revised Rate Schedules; and Changes to its Tariff (2023) – (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2022-0233

PCMG and Associates LLC

16. In re: Application of Southern Maryland Electric Cooperative, Inc., for Authority to Revise Its Rates and Charges for Electric Service and Certain Rate Design Changes (2023) – (Appearance: cost of service and rate design on behalf of the Maryland Office of the People's Counsel)
    MD PSC Case No. 9688

17. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2023 (2022) – (Appearance: business risk and cost of equity on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 22-04-012

18. In re: Valley Energy, Inc. General Base Rate Increase Filing (2022) – (Appearance: gas cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2022-3032300

19. In re: Citizens' Electric Company General Base Rate Increase Filing (2022) – (Appearance: electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2022-3032369

20. In re: PECO Energy Company (Gas Division) General Base Rate Increase Filing (2022) – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2022-3031113

21. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 22-GREC-05

22. In re: Petition of Liberty Utilities (New England Natural Gas Company Corp.) d/b/a Liberty for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 22-GREC-04

23. In re: Petition of Berkshire Gas Company for Approval of its 2021 Gas System Enhancement Plan Reconciliation Filing (2022) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 22-GREC-02

24. In re: Nova Scotia Power 2022-2024 General Rate Application (2022) - (Appearance: cost of service on behalf of the Nova Scotia Utility and Review Board)
    NS UARB M10431

25. In re: the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
    ND PSC Case No. PU-20-441

26. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2022 and to Reset the Annual Cost of Capital Mechanism (2021) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 21-08-014

27. In re: Petition of HPBS, Inc. for review and approval of Central Scheduling System (CSS) charge increase and revised CSS schedule (2021) – (Appearance: rate design on behalf of the Hawaii Department of Commerce and Consumer Affairs)
    HI DCCA Docket No. PTP-2021-001

28. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 21-GREC-06

29. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 21-GREC-05

30. In re: Petition of Berkshire Gas Company for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

31. In re: the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
    ND PSC Case No. PU-20-441

32. In re: Pike County Light & Power Company 2020 General Base Rate Increase Filing – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3022134 and R-2020-3022135

33. In re: Young Brothers LLC's Application for Approval of a New Cost of Service Model (2020) – (Appearance: cost of service on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2020-0135

34. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-06

35. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-05

36. In re: Petition of Berkshire Gas Company for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

37. In re: Pittsburgh Water and Sewer Authority 2020 General Base Rate Increases 2020 – (Appearance: multi-year rate plan and performance-based ratemaking on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3017970 and R-2020-3017951

38. In re: Commonwealth Edison Company Petition for approval of a Revision to Integrated Distribution Company Implementation Plan Creation of Rate Residential Time of Use Pricing Pilot ("Rate RTOUP") – On Rehearing (2020) – (Appearance: price signal and customer response on behalf of the Illinois Attorney General)
    IL Commerce Commission Docket Nos. 18-1725/18-1824

39. In re: Hawaii Electric Company, Inc. Application for Approval of a General Rate Increase and Revised Rate Schedules and Rules (2019) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2019-0085

PCMG and Associates LLC

40. In re: Application of San Diego Gas & Electric Company for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Increase its Overall Rate of Return, (v) Modify its Adopted Cost of Capital Mechanism Structure, and (vi) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
CA Public Utilities Commission Application 19-04-017

41. In re: Proposed Amendments to N.J.A.C. 14:9 Adoption of Water and Sewer Uniform System of Accounts (2019) – (Assistance to counsel: water and sewer accounting on behalf of the Division of Rate Counsel)
NJ Board of Public Utilities Docket Nos. WX19050612 and WX19050613

42. In re: Petition of Public Service Electric and Gas Company for Approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program (2019) – (Assistance to Counsel: infrastructure replacement accounting)
NJ Board of Public Utilities Docket No. GE19040522

43. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 19-GREC-06

44. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 19-GREC-05

45. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2019) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9602

46. In re: PECO Energy Company Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment (2019) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
PA Public Utility Commission Docket No. M-2018-3005860

PCMG and Associates LLC

47. In re: PECO Energy Company Transmission Formula Rate Application (2018) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-1519-000

48. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-06

49. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-05

50. In re: The Application of the Potomac Edison Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9490

51. In re: Rate Applications of Kansas City Power & Light – Missouri and Kansas City Power & Light – Greater Missouri Operations (2018) – (Appearance: consolidated operations, cost of service and rate design on behalf of the Missouri Office of Public Counsel)
    MO Public Service Commission Case Nos. ER-2018-0145 and ER-2018-0146

52. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9472

53. In re: Mid-Atlantic Interstate Transmission, L.L.C. 2018 Transmission Formula Rate Protocol Filings (2018) - (Analysis and Advice to Counsel: accounting)
    Federal Energy Regulatory Commission Docket ER17-211-000

54. In re: The Gas Company d/b/a Hawaii Gas Application for Approval of Rate Increases and Revised Rate Schedules and Rules (2017) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2017-0105

55. In re: Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

PCMG and Associates LLC

56. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9455

57. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

58. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

59. In re: In the matter of the application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9447

60. In re: PJM Interconnection, L.L.C. - PECO Energy Company Transmission Formula Rate Application (2017) - (Analysis and Advice to Counsel: accounting, cost of service and rate design)
    Federal Energy Regulatory Commission Docket ER17-1519-000

61. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) - (Appearance: prudence/used and useful and plant accounting re. accelerated asset replacement program on behalf of the Illinois Citizens Utility Board)
    IL Commerce Commission Docket No. 17-0124

62. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9443

63. In re: PJM Interconnection, L.L.C. - Rockland Electric Company Transmission Rate Application (2017) (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket ER17-856-000

PCMG and Associates LLC

64. In re: PJM Interconnection, L.L.C. - Mid-Atlantic Interstate Transmission, L.L.C. Transmission Formula Rate Application (2016) - (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-211-000

65. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9424

66. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9418

67. In re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

68. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

69. In re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Appearance: compliance with statutes and regulations, prudence, cost/benefit, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

70. In re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel: tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2016-00035

71. In re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (2016) - (Appearance: productivity adjustments/performance based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

72. In re: Emera Maine, Proposed Rate Increase in Rates (2016) - (Analysis and Advice to to Counsel: evaluation of management audit of implementation of Customer Information System on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2015-00360

73. In re: The Merger of the Southern Company and AGL Resources Inc.- Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Appearance: earnings, synergy savings, rates, operations, supply procurement, safety, and reliability on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9404

74. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Firm Transportation Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-142

75. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015-2016)
    - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-130

76. In re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Gaz Metro LNG, L.P.; and National Grid LNG (2015- 2016) - (Analysis and Advice to Counsel: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-129

77. In re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor Compliance Filing (2015) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-55

78. ENMAX Energy Corporation (EEC) 2015-2016 Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Appearance: cost allocation, rate design, non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

79. In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (2014) - (Advice to Counsel: impact on customers on behalf of the New Jersey Division of Rate Counsel)
    NJ Board of Public Utilities BPU Docket No. EM1406

80. In re: Application of Baltimore Gas and Electric Company For Adjustments To Its Electric and Gas Base Rates (2014) (Analysis and Advice to Counsel in Settlement: earnings, investment tracker, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9355

81. In re: Columbia Gas of Massachusetts CY2013 Targeted Infrastructure Reinvestment Factor Compliance Filing (2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 14-83

82. In re: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (2014-2015) - (Analysis and Advice to Counsel: impact on rates and consolidation of rates on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.U-33244

83. In the Matter of the Application of Ohio Power Company to Adopt a Final Implementation Plan for the Retail Stability Rider (2014) - (Analysis and Advice to Counsel: rate design)
    OH Public Utilities Commission Case No. 14-1186-EL-RDR

84. In re: Examination of Long-Term Natural Gas Hedging Proposals (2014-2015) - (Analysis and Advice to Counsel: natural gas procurement on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No.R-32975-LPSC, ex parte

85. In re: 2013 Integrated Resource Planning Process for Southwestern Electric Power Company Pursuant to General Order Dated April, 20, 2012 (2014-2015 - (Analysis and Advice to Counsel: IRP design and evaluation on behalf of the Louisiana Public Service Commission Staff)
    LA Public Service Commission Docket No. I-33013 SWEPCO, ex parte

86. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Adopt an Infrastructure Replacement Surcharge Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9332

87. In the Matter of the Application of Baltimore Gas and Electric Company for Approval of a Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9331

88. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2013-2014) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 13-115

89. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2013) - (Appearance: cost allocation and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

90. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2013) - (Appearance: expense tracker design/rates and evaluation on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9316

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	15,995,100	13,019,762	2,975,339	15,152,500	1,945,602	631,708	302,550
RRW	6	Net Operating Income (Present Rates)		2,145,215	836,814	653,463	183,351	1,036,408	192,600	64,144	15,249
RRW	7	Rate of Return @ Present Rates		6.30%	5.23%	5.02%	6.16%	6.84%	9.90%	10.15%	5.04%
RRW	8	Relative Rate of Return		1.00	0.83	0.80	0.98	1.08	1.57	1.61	0.80
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	1,530,809	1,245,763	285,046	1,459,472	186,982	60,924	29,009
RRW	18	Sales Revenue Required @ Claimed ROR		9,504,985	4,892,684	4,034,020	858,664	3,860,490	561,282	115,881	74,647
RRW	19	Sales Revenue Deficiency		2,143,900	1,275,965	1,082,405	193,560	819,588	19,974	3,253	25,120
RRW	20	Percent Increase Required		29.12%	35.28%	36.67%	29.10%	26.95%	3.69%	2.89%	50.72%
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	$0.1380	$0.1405	$0.1273	$0.1067	$0.0457	$0.3532	$0.4909
RRW	23	Revenue Deficiency $/kWh		$0.0254	$0.0360	$0.0377	$0.0287	$0.0226	$0.0016	$0.0099	$0.1652
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	18,288,712	14,883,246	3,405,466	17,436,450	2,233,894	727,869	346,575
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	1,413,548	1,107,982	305,565	1,432,119	308,013	93,754	19,756
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%	7.73%	7.44%	8.97%	8.21%	13.79%	12.88%	5.70%
RRW	34	Relative Rate of Return		1.00	0.92	0.89	1.07	0.98	1.65	1.54	0.68
RRW	35										
RRW	36										
RRW	37	Relative Rate of Return				0.80	0.98	1.08	1.57	1.61	0.80
RRW	38	Rate of Return		8.37%		6.66%	8.18%	9.08%	13.14%	13.48%	6.69%
RRW	39	Rate Base at Future Test Year 09/30/2025		39,033,500		14,883,246	3,405,466	17,436,450	2,233,894	727,869	346,575
RRW	40	Return		3,268,752		991,771	278,624	1,583,435	293,603	98,127	23,192
RRW	41	Operating Expenses Including Taxes		6,362,846		2,838,256	585,852	2,454,311	383,158	55,417	45,852
RRW	42		98.69%	9,631,598		3,830,027	864,476	4,037,746	676,761	153,543	69,044
RRW	43	Proposed Base Electric Sales Revenues		9,504,985		3,779,679	853,112	3,984,668	667,865	151,525	68,136
RRW	44	Class Distribution		100.00%		39.77%	8.98%	41.92%	7.03%	1.59%	0.72%
RRW	45	Percent increase		29.12%		28.05%	28.27%	31.04%	23.38%	34.54%	37.57%
RRW	46										
RRW	47										
RRW	48										
RRW	49										
RRW	50										

Customer Class	Current	Recommended	Percent Increase	Class Percent Distribution
SC-1 Residential	2,951,615	3,482,226	17.98%	39.77%
SC-1 Residential Space/Water Heating	665,104	784,915	18.01%	8.98%
SC-2 Secondary	3,040,902	3,600,199	18.39%	41.92%
SC-2 Primary	541,306	635,100	17.33%	7.03%
SC-3 Municipal Lighting	112,628	133,842	18.84%	1.59%
SC-4 Private Area Lighting	49,527	59,133	19.40%	0.72%
Total	7,361,084	8,695,415	18.13%	100.00%

OCA Revenue Requirement Increase 1,334,200

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 3, 2025

Signature: Karl R. Pavlovic

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

COMMONWEALTH OF PENNSYLVANIA

DARRYL A. LAWRENCE
Acting Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

@pa_oca
/pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

May 1, 2025

Via Electronic Mail
Administrative Law Judge Marta Guhl (mguhl@pa.gov)
Administrative Law Judge Alphonso Arnold III (alphonarno@pa.gov)
Office of Administrative Law Judge
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

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

Dear Honorable Judges Guhl and Arnold:

Please find enclosed a copy of the Rebuttal Testimony being submitted on behalf of the Office of Consumer Advocate in this proceeding, as follows:

- OCA Statement 3R: Rebuttal Testimony of Karl Pavlovic
- Verification of Karl Pavlovic

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectfully submitted,

/s/ Jacob D. Guthrie
Jacob D. Guthrie, Esq.
Assistant Consumer Advocate
PA Attorney I.D. # 334367
Email: JGuthrie@paoca.org

Enclosures

cc: Secretary Matthew L. Homsher (Cover Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

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

I hereby certify that I have this day served a true copy of the following documents, the Office of Consumer Advocate's Rebuttal Testimony, as follows:

- OCA Statement 3R: Rebuttal Testimony of Karl Pavlovic
- Verification of Karl Pavlovic

upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below.

Dated this 1st day of May, 2025.

SERVICE BY E-MAIL ONLY

Carrie B. Wright, Esq.
Michael Podskoch, Esq.
Bureau of Investigation & Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
P. O. Box 3265
Harrisburg, PA 17105-3265
carwright@pa.gov
mpodskoch@pa.gov
Counsel for I&E

Whitney E. Snyder, Esq.
Erich W. Struble, Esq.
HMS Legal LLP f/k/a
Hawke McKeon and Sniscak LLP
501Corporate Circle, Suite 302
Harrisburg, PA 17110
wesnyder@hmslegal.com
ewstruble@hmslegal.com
Counsel for Pike County L&P

Rebecca Lyttle, Esq.
Steven C. Gray, Esq.
Office of Small Business Advocate
Forum Place
555 Walnut Street, 1st Floor
Harrisburg, PA 17101
relyttle@pa.gov
sgray@pa.gov
Counsel for OSBA

/s/ Jacob D. Guthrie
Jacob D. Guthrie, Esq.
Assistant Consumer Advocate
PA Attorney I.D. # 334367
Email: JGuthrie@paoca.org

Ryan Morden, Esq.
Assistant Consumer Advocate

Melanie Joy El Atieh, Esq.
Deputy Consumer Advocate
Email: OCAPIKEBRC2024@paoca.org

Counsel for:
Darryl A. Lawrence
Acting Consumer Advocate

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
717-783-5048

Dated: May 1, 2025

OCA St. No. 3R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2024-3052359**
Pike County Light & Power Company (Electric)	**)**	

REBUTTAL TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 1, 2025

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. ARE YOU THE SAME KARL RICHARD PAVLOVIC WHO SUBMITTED DIRECT TESTIMONY ON APRIL 3, 2025 IN THIS PROCEEDING?

A. Yes. Exhibit KRP-1 to my April 3, 2025 direct testimony summarizes my qualifications and experience and contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony and responds to the Statement No. 1 Direct Testimony of Mark D. Ewen regarding (1) OSBA's support and acceptance of PCLP's minimum-size method of classification and allocation of electric distribution plant to classes and (2) OSBA's proposed class revenue allocation.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows. Section III A summarizes my findings, conclusions and recommendations. Section III B addresses OSBA's acceptance of the minimum-size method of classification and allocation of electric distribution plant. Section III C addresses OSBA's proposed class revenue allocation.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR TESTIMONY.

A. As detailed below:

- I recommend the Commission reject OSBA's use of the ECOSS as a guide to revenue allocation.
- I recommend the Commission reject OSBA's proposed revenue allocation.

B. OSBA's ACCEPTANCE OF PCLP's MINIMUM-SIZE METHOD

Q. WHAT IS WITNESS EWEN'S TESTIMONY REGARDING PCLP'S MINIMUM-SIZE METHOD?

A. Witness Ewen describes PCLP minimum-size classification and allocation of its electric distribution plant, [1] but offers no evidence in support of PCLP's use of the minimum-size method. He then states that he finds PCLP's use of the minimum-size method to be reasonable, offering no evidence to support its reasonableness, and notes that PCLP's methodology is consistent with Commission precedent.[2]

---

[1] OSBA Statement No. 1 Direct Testimony of Mark D. Ewen (Ewen Direct), page 7 line 27 to page 8 line 6.

[2] Ewen Direct, page 8 lines 7-10.

Q. WHAT IS YOUR RESPONSE TO WITNESS EWEN'S TESTIMONY REGARDING PCLP's USE OF THE MINIMUM-SIZE METHOD?

A. My response is two-fold. First, as I demonstrated in my direct testimony, there is no basis in theory, system design and operating practice, or empirical quantitative data to support PCLP's use of the minimum-size method to classify as customer-related any portion of its electric distribution plant costs.[3] As evidence of this, when I requested PCLP's planning, design, and operating standards and procedures for Plant Accounts 364-368, the documents provided clearly demonstrate that the number of customers on PCLP's distribution system plays no role in how PCLP designs, plans, and operates the plant recorded in these account numbers.[4] Second, as I explained in my direct testimony the fact that PCLP's use of the minimum-size method is consistent with Commission precedent is not dispositive because cost classification in a rate proceeding is a forward-looking exercise that depends only on the planning, design and operation of a electric distribution system.[5] As the Commission has previously noted, the best-suited cost of service methodology depends on the circumstances on a case-by-case basis.[6]

---

[3] Pavlovic Direct, page 8 line 5 to page 14 line 14.
[4] Pavlovic Direct, page 9 lines 1-15.
[5] Pavlovic Direct, page 10 lines 10-22.
[6] Pennsylvania Public Utility Commission v. PECO Energy – Gas Division, R-2020-3018929, 7/17/21 Opinion and Order at 230 - "We agree with PAIEUG that the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis."

Q. WHAT IS YOUR RECOMMENDATION REGARDING OSBA ACCEPTANCE OF PCLP'S ECOSS AS A GUIDE TO REVENUE ALLOCATION?

A. For the reasons above I recommend the Commission reject OSBA's use of the ECOSS as a guide to revenue allocation.

C. OSBA'S CLASS REVENUE ALLOCATION

Q. WHAT CLASS REVENUE ALLOCATION DOES OSBA PROPOSE?

A. Witness Ewen does not present in his testimony a proposed class revenue allocation, instead he provides only a proposed allocation of the revenue increase to classes.[7] He does, however, calculate both in his workpapers.[8] Examination of his workpaper calculations reveals two issues. First, his proposed SC2-S revenue increase of $217,606 in his testimony Table IEc-4 is wrong. The workpapers show that the correct number is $271,606.[9] Second, the total and class current revenues he uses to calculate his proposed revenue allocation in his workpapers[10] are not the current revenues in PLCP's cost study.[11] In Table 1R below I have calculated the class revenue allocation implied by his proposed allocation of the increase in revenue using PCLP's current revenues and the correct SC2-S revenue increase. As a consequence, the class revenue increases in Table 1R deviate slightly from the class revenue increases shown in Witness Ewen's Table IEc-4.

---

[7] Ewen Direct, page 12 Table IEc-4.
[8] IEc WP1 PCL&P Electric ECOSS Replication.xlsx, tab HTY to FTY, rows 60 and 62.
[9] IEc WP1 PCL&P Electric ECOSS Replication.xlsx, tab HTY to FTY, row 62, column D..
[10] IEc WP1 PCL&P Electric ECOSS Replication.xlsx, tab HTY to FTY, row 50.
[11] PCLP Exhibit E-6, Schedule PMN-2-E, page 1, line 6

Table 1R - OSBA Proposed Revenue Allocation					
Customer Class	**Current**	**Proposed Revenue Increase**	**Proposed Revenue Allocation**	**Percent Increase**	**Class Percent Distribution**
SC-1 Residential	2,951,615	1,289,265	4,240,880	43.68%	46.01%
SC-1 Residential Space/Water Heating	665,104	178,612	843,716	26.85%	9.15%
SC-2 Secondary	3,040,902	271,606	3,312,508	8.93%	35.94%
SC-2 Primary	541,306	48,348	589,654	8.93%	6.40%
SC-3 Municipal Lighting	112,628	47,304	159,932	42.00%	1.74%
SC-4 Private Area Lighting	49,527	20,801	70,328	42.00%	0.76%
Total	7,361,082	1,855,936	9,217,018	25.21%	100.00%

Q. HOW AND WHY DID OSBA DEVELOP THE REVENUE INCREASES IN TABLE 1R?

A. As to how, Witness Ewen states that the proposed revenue increases move rates into line with costs subject to a 1.75 times system average limit.[12] He does not provide any evidence in support of the 1.75 times system average limit. As to why, Witness Ewen is quite explicit in his testimony.

> **"**In my view, the Company's revenue allocation is overly biased towards rate gradualism concerns at the expense of making progress toward cost-based rates. The usual 'rule of thumb' in Pennsylvania is that rate increases for any individual class should not exceed 1.5 or 2.0 times the system average. PCL&P's rationale for limiting the rate increase for the SC1 classes to 1.1 times the system average – chosen arbitrarily to mitigate the rate increase for Residential customers – is not

[12] Ewen Direct, page 11 lines 3-4.

> convincing. More importantly, such a low cap limits the Company's ability to bring rates more in line with allocated costs."[13]

In a footnote to this testimony he quotes what he takes to be PCLP's position on the issue of gradualism.

> "The resulting overall ROR [rate of return] requested yields a Residential increase of 32% which we believe to be considerable for the Company's smaller customers. As a result, the proposed limit of 110% was targeted to mitigate the Residential increase which resulted in a minor shift away from unity which was balanced for the relative size of the class increases."[14]

To be clear here, Witness Ewen and OSBA do not take +40% revenue increases to PCLP's non-commercial classes to constitute rate shock.

Q. HOW DO OSBA'S PROPOSED REVENUE INCREASE PERCENTAGES COMPARE TO THOSE OF PCLP AND OCA?

A. Table 2R compares class by class the percentage increases proposed by OSBA, PCLP and OCA. The OCA percentages are based on PCLP's ECOSS without minimum-size classification and allocation.

[13] Ewen Direct, page 11 line 9 to page 12 line 2.
[14] OSBA-Pike-Electric-I-15.

Table 2R - Comparison of OSBA Revenue Increase Percentages with the Revenue Increase Percentages proposed by PCLP and OCA			
Customer Class	**OSBA**	**PCLP** [15]	**OCA** [16]
SC-1 Residential	43.68%	32.00%	28.05%
SC-1 Residential Space/Water Heating	26.85%	32.19%	28.27%
SC-2 Secondary	8.93%	26.05%	31.04%
SC-2 Primary	8.93%	26.05%	23.38%
SC-3 Municipal Lighting	42.00%	32.04%	34.54%
SC-4 Private Area Lighting	42.00%	32.04%	37.57%
Total	25.21%	29.12%	29.12%

Q. HOW DOES OSBA'S PROPOSED REVENUE ALLOCATION COMPARE TO PCLP'S AND OCA'S PROPOSED CLASS REVENUE ALLOCATIONS?

A. Table 3R below compares OSBA's revenue allocation with PCLP's revenue allocation and OCA's revenue allocation which is based on PCLP's ECOSS without minimum-size classification and allocation.

Table 3R - Comparison of OSBA Revenue Allocation with the Revenue Allocations proposed by PCLP and OCA			
Customer Class	**OSBA**	**PCLP**	**OCA**
SC-1 Residential	4,240,880	3,896,239	3,779,679
SC-1 Residential Space/Water Heating	843,716	879,184	853,112
SC-2 Secondary	3,312,508	3,833,137	3,984,668
SC-2 Primary	589,654	682,313	667,865
SC-3 Municipal Lighting	159,932	148,711	151,525
SC-4 Private Area Lighting	70,328	65,395	68,136
Total	9,217,018	9,504,985	9,504,985

[15] Pavlovic Direct, page 18, Table 3.
[16] Pavlovic Direct, page 22, Table 6.

Q. WHAT IS YOUR RESPONSE TO OSBA'S PROPOSED REVENUE ALLOCATION?

A. My response is three-fold.

First, I note that OSBA's proposed revenue allocation rests on an overall revenue that is $287,967 ($9,504,985 minus $9,217,018) lower than PCLP's and OCA's revenue. Witness Ewen provides no explanation for this discrepancy.

Second, OSBA's proposed revenue allocation takes as a guide PCLP's minimum-size ECOSS results, which is not consistent with cost causation and thereby over allocates costs to the residential classes with combined 4,304[17] customers and under allocates costs to the 1,033[18] combined SC-2, SC-3 and SC-4 customers.[19]

Third, OSBA'S proposed revenue allocation clearly selectively violates the ratemaking principle of gradualism regarding the residential and lighting classes to the benefit of the commercial classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING OSBA'S PROPOSED REVENUE ALLOCATION?

A. For the reasons above I recommend the Commission reject OSBA's proposed revenue allocation.

---

[17] Exhibit E-6, Schedule PMN-4-E, page 14, line 77, column d.
[18] Exhibit E-6, Schedule PMN-4-E, page 14, line 77, columns g-j.
[19] Pavlovic Direct, page 14 line 19 to page 15 line 6.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by OSBA.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in OCA Statement 3R, the Rebuttal Testimony of Karl R. Pavlovic, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 1, 2025

Signature: ______________________
Karl R. Pavlovic

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

OCA St. No. 3-SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. R-2024-3052359**
Pike County Light & Power Company (Electric)	)	

SURRREBUTTAL TESTIMONY OF

KARL RICHARD PAVLOVIC

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 15, 2025

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. ARE YOU THE SAME KARL RICHARD PAVLOVIC WHO SUBMITTED DIRECT AND REBUTTAL TESTIMONIES ON APRIL 3, 2025 AND MAY 1, 2025 IN THIS PROCEEDING?

A. Yes. Exhibit KRP-1 to my April 3, 2025 direct testimony summarizes my qualifications and experience and contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies.

II. PURPOSE OF SURREBUTTAL TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My surrebuttal testimony addresses (1) PCLP Statement No. 1-R Rebuttal Testimony of Paul M. Normand which responds to OCA's recommendations that PCLP's minimum-size ECOSS be rejected and the residential customer charge remain at its current level; and (2) OSBA Statement No. 1-R Rebuttal Testimony of Mark D. Ewen which responds to OCA's rejection of PCLP's minimum-size ECOSS and OCA's proposed class revenue allocation.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows. Section III.A summarizes my findings, conclusions and recommendations. Section III.B addresses PCLP's and OSBA's ECOSS rebuttal testimonies. Section III.C addresses PCLP's residential customer charge rebuttal testimony. Section III.D addresses OSBA's revenue allocation rebuttal testimony.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No.

III. DISCUSSION

A. SUMMARY

Q. PLEASE SUMMARIZE THE SUBSTANCE OF YOUR SURREBUTTAL TESTIMONY.

A. As detailed below:

- The rebuttal testimonies of PCLP and OSBA provide no grounds for modification or withdrawal of my recommendation that the Commission reject PCLP's ECOSS with minimum-size classification and allocation and accept PCLP's ECOSS without minimum-size classification and allocation as a guide to revenue allocation.
- The rebuttal testimony of PCLP provides no grounds for modification or withdrawal of my recommendation that the residential customer charge be maintained at its current level in order to incentivize residential customer conservation and give residential customers greater control over their distribution bills.
- The rebuttal testimony of OSBA provides no grounds for modification or withdrawal of my proposed class revenue allocation.

B. PCLP AND OSBA ECOSS REBUTTAL TESTIMONY

1. PCLP ECOSS REBUTTAL TESTIMONY

Q. WHAT WAS YOUR DIRECT TESTIMONY REGARDING PCLP'S ECOSS WITH MINIMUM-SIZE CLASSIFICATION AND ALLOCATION?

A. In my direct testimony I demonstrated that there is no basis in theory, system design and operating practice, or empirical quantitative data to support PCLP's use of the minimum-size method to classify as customer-related any portion of its electric distribution plant costs accounts 364-368.[1] I concluded that the PCLP's distribution costs in plant accounts 364-368 are properly classified as 100 percent demand-related and properly allocated to classes using PCLP's demand allocation factors.[2]

Q. WHAT IS PCLP'S REBUTTAL TESTIMONY REGARDING ITS ECOSS WITH MINIMUM-SIZE CLASSIFICATION AND ALLOCATION OF ACCOUNTS 364-368?

A. Witness Normand's rebuttal testimony consists of four assertions that are intertwined with his response to OCA's residential customer charge proposal, which I discuss below. First, he states that he used the minimum-size method to calculate a customer component (1) to provide continuity with PCLP's last ECOSS; and (2) to recognize that secondary lines are closer and influenced by population density and geography.[3] Second, he asserts that secondary circuits and transformers entail "local facility" customer-related costs in addition to secondary demand-related costs because they are closer to customers than

[1] OCA Statement No. 3 Direct Testimony of Karl Richard Pavlovic (Pavlovic Direct), page 8 line 5 to page 14 line 4.
[2] Pavlovic Direct, page 14 lines 4-14.
[3] PCLP Statement No. 1-R Rebuttal Testimony of Paul M. Normand (Normand Rebuttal), page 3 lines 3-12.

primary facilities.[4] Third, he states that he disagrees with my conclusion "that classifying any portion of accounts 365(sic)-368 as customer-related contravenes the principle of cost causation" because the minimum-size classification of customer-related costs was only applied to the low voltage secondary network.[5] Fourth, he states that he disagrees with my reclassification as demand-related of his purported secondary customer-related costs in accounts 364-368 because his ECOSS with minimum-size classification shows that customer-related customer costs are only 32.2% of accounts 364-368 costs because the costs of primary facilities in accounts 364-368 are classified as 100% demand-related.[6]

Q. WHAT IS YOUR RESPONSE TO WITNESS NORMAND'S REBUTTAL TESTIMONY?

A. My response is four-fold.

First, as to continuity, as I explained in my direct testimony the fact that PCLP's used the minimum-size method in the past is not dispositive because cost classification in a rate proceeding is a forward-looking exercise that depends only on the planning, design and operation of an electric distribution system.[7] As the Commission has previously noted, the best-suited cost of service methodology depends on the circumstances on a case-by-case basis.[8]

---

[4] Normand Rebuttal, page 4 lines 12-20.
[5] Normand Rebuttal, page 7 lines 3-14.
[6] Normand Rebuttal, page 8 lines 1-9, citing to Exhibit E-6, Schedule PMN-4-E, page 3 of 27(sic).
[7] Pavlovic Direct, page 10 lines 10-22.
[8] Pennsylvania Public Utility Commission v. PECO Energy – Gas Division, R-2020-3018929, 7/17/21 Opinion and Order at 230 - "We agree with PAIEUG that the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis."

Second, witness Normand provides no evidence supporting his assertion that because secondary facilities are closer to customers than primary facilities, they entail customer-related costs in addition to their demand-related costs.

Third, witness Normand's assertion that the principle of cost causation is not contravened because minimum-size classification was only applied to secondary facilities is a text book example of the logical fallacy known as "begging the question," i.e., assuming the point to be proved, since he has previously assumed without supporting evidence that secondary facilities have customer-related costs in addition to their demand related costs.

Fourth, Witness Normand's assertion that he disagrees with my testimony that secondary costs should be classified as 100% demand-related because PCLP's ECOSS shows 32.2% of total distribution costs to be customer costs simply repeats the fallacy noted above, since his ECOSS assumes without supporting evidence that secondary facilities have customer-related costs in addition to their demand related costs.

Q. WHAT DO YOU CONCLUDE REGARDING WITNESS NORMAND'S ECOSS REBUTTAL TESTIMONY?

A. For the reasons above, I conclude that witness Normand's rebuttal testimony provides no grounds for modification or withdrawal of my recommendation in my direct testimony that the Commission: (1) reject PCLP's ECOSS with minimum-size classification and allocation; and (2) accept PCLP's ECOSS without minimum-size classification and allocation as a guide to revenue allocation.

2. OSBA ECOSS REBUTTAL TESTIMONY

Q. WHAT IS OSBA'S REBUTTAL TESTIMONY REGARDING ITS USE OF THE ECOSS WITH MINIMUM-SIZE CLASSIFICATION AND ALLOCATION OF ACCOUNTS 364-368?

A. OSBA witness Ewen's rebuttal testimony consists of (1) two rationales that purport to support the ECOSS's assumption that there is a customer cost component to accounts 364-368;[9] (2) the assertion that the ECOSS with minimum-size classification is consistent with PLCP's previous proceedings;[10] and (3) the assertion that OCA IR-8-4 provides no evidence that demand is the only driver cause or driver of PCLP's secondary distribution plant.[11]

The first rationale is the case of an existing distribution system expanding into a new area to connect new customers.[12] Witness Ewen states that in such an expansion the system will incur the costs of additional poles, conductors and transformers to connect to the new customers. Next, he asserts, without supporting evidence, that some of these new costs are related to increased demand and some to the need to interconnect customers. He then reasons backwards that most of the existing distribution system consists of such expansions and concludes that most of the distribution system is related to both demand and customers.

The second rationale rests on the purported fact that it is generally less costly per unit of demand to provide service to larger commercial/industrial customers who are often located

---

[9] OSBA Statement No. 1-R Rebuttal Testimony of Mark D. Ewen (Ewen Rebuttal), page 2 lines 8-16 and lines 17-23.
[10] Ewen Rebuttal, page 2 lines 24-27.
[11] Ewen Rebuttal, page 3 lines 8-16.
[12] Ewen Rebuttal, page 2 lines 8-16.

in narrower geographic areas than it is to provide service to geographically dispersed residential areas.[13]

Q. WHAT IS YOUR RESPONSE TO OSBA WITNESS EWEN'S REBUTTAL TESTIMONY?

A. My response is four-fold.

First, regarding the first rationale, OSBA witness Ewen conflates the word "related" with the technical cost analysis terms "demand-related" and "customer-related." That customers are undisputedly related physically to the distribution system to which they are connected, does not constitute evidence that they are a cost causative factor of the distribution system. More importantly, with this conflation witness Ewen commits the fallacy of begging the question by assuming at the outset that customers are a cost causative factor for the distribution system.

Second, regarding the second rationale, it is not clear what OSBA witness Ewen means by "less costly per unit of demand" and even less clear what relevance this has to the question of whether customers are or are not a cost causative factor of distribution systems. Moreover, it is clear that whatever witness Ewen intends with this rationale, it rests on the assumption that larger commercial and industrial customers are served in geographically compact sections of the distribution system while residential customers are served in geographically dispersed sections of the distribution system. This unsupported assumption is easily countered by the observation that in fact residential customers are also serviced

[13] Ewen Rebuttal, page 2, lines 17-23.

by compact urban sections of the distribution system and commercial and industrial customers are also serviced by dispersed rural sections of the distribution system.

Third, as I pointed out above, that PCLP used the minimum-size method in the past is not dispositive because cost classification in a rate proceeding is a forward-looking exercise that depends only on the planning, design and operation of an electric distribution system.[14]

Fourth, regarding OCA IR-8-4, witness Ewen has apparently failed to examine PCLP's 3/24/25 supplemental response to OCA IR-8-4 which "clearly demonstrate that the number of customers on PCLP distribution system plays no role in the design, planning, and operation of PCLP's plant recorded in plant accounts 364-368."[15]

Q. WHAT DO YOU CONCLUDE REGARDING WITNESS EWEN'S ECOSS REBUTTAL TESTIMONY?

A. For the reasons above, I conclude that neither PCLP witness Normand's nor OSBA witness Ewen's rebuttal testimony provides any grounds for modification or withdrawal of my recommendation in my direct testimony that the Commission reject PCLP's ECOSS with minimum-size classification and allocation and accept PCLP's ECOSS without minimum-size classification and allocation as a guide to revenue allocation.

---

[14] Pavlovic Direct, page 10 lines 10-22; see also OCA Statement No. 3R Rebuttal Testimony of Karl Richard Pavlovic (Pavlovic Rebuttal), page 3 lines 10-15.
[15] Pavlovic Direct, page 9 lines 10-13; see also Pavlovic Rebuttal, page 3 lines 6-10.

C. PCLP RESIDENTIAL CUSTOMER CHARGE REBUTTAL TESTIMONY

Q. WHAT WAS YOUR DIRECT TESTIMONY REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. In my direct testimony, I explained that PCLP's proposed increase to the residential customer charge provides no discernible rate making benefit because the customer charge is not a real actionable price signal to residential customers.[16] Placing the proposed rate increase in the volumetric charge, which is an actionable price signal, will provide residential customers with an increased incentive to engage in conservation and the ability to exercise control over a larger portion of their monthly electric distribution bill and for those reasons I recommended maintaining the residential customer charge at its current level.[17]

Q. WHAT IS PCLP'S REBUTTAL TESTIMONY REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. PCLP witness Normand asserts that maintaining the current residential customer charge will encourage subsidies and uneconomic pricing of the volumetric charge.[18] To support this assertion he relies on four points.

[16] Pavlovic Direct, page 25 line 12 to page 26 line 1.
[17] Pavlovic Direct, page 26 lines 1-9.
[18] Normand Rebuttal, page lines 19-21.

First, he correctly notes that electric distribution costs are fixed costs and have no relationship to volumetric consumption, but then asserts that the use of volumetric charges results in subsidies and poor customer cost recovery.[19]

Second, he draws a distinction between "fixed customer costs" of the meters and services connecting customers to the distribution system and "local facilities costs" which are the customer-related component costs of secondary circuits and transformers discussed above.

Third, he asserts that local facilities costs should be recovered through the monthly customer charge so to avoid introducing additional cross subsidies to the volumetric charge.[20]

Fourth, he compares the current and proposed residential customer charges to the combined residential fixed and local facilities customer cost[21] and notes that both the current and proposed residential customer charges recover only a small portion of the combined fixed and local facilities charges with the remaining costs recovered by the remaining customers in the class on a kWh basis.[22]

Q. WHAT IS YOUR RESPONSE TO WITNESS NORMAND'S REBUTTAL TESTIMONY?

A. My response is three-fold.

---

[19] Normand Rebuttal, page 2 lines 16-23.
[20] Normand Rebuttal, page 4 line23 to page 5 line 3.
[21] Normand Rebuttal, page 5 lines 4-7 and Table ER1.
[22] Normand Rebuttal, page 5 lines 9-12.

First, witness Normand does not, anywhere in his rebuttal testimony, address my testimony that the customer charge is not a real actionable price signal, while the volumetric charge is a real actionable price signal.

Second, I note that witness Normand does not define "subsidies," "cross subsidies" or "poor cost recovery." Presumably, he views these to be negative outcomes, but so long as they are undefined, it is not possible for OCA or the Commission to either affirm or deny that they are actionable negative outcomes. It is also impossible to weigh the undefined and unsupported purported negative outcomes against the positive outcomes of incentivizing residential customer conservation and greater residential customer control over distribution bills that result from recovering customer costs through the volumetric charge.

Third, witness Normand asserts that both customer costs and local facilities cost should be recovered through the fixed customer charge but offers no evidence other than his unsupported assertion that not recovering these costs through the customer charge leads to undefined purported negative outcomes of subsidies and poor cost recovery.

Q. WHAT DO YOU CONCLUDE REGARDING WITNESS NORMAND'S REBUTTAL TESTIMONY?

A. For the reasons above, I conclude that witness Normand's rebuttal testimony provides no grounds for modification or withdrawal of my recommendation in my direct testimony that the residential customer charge be maintained at its current level in order to incentivize customer conservation and give customers greater control over their distribution bills.

D. OSBA REVENUE ALLOCATION REBUTTAL TESTIMONY

Q. WHAT WAS YOUR DIRECT TESTIMONY REGARDING REVENUE ALLOCATION?

A. In my direct testimony I proposed a revenue allocation taking PCLP's ECOSS without minimum-size classification as guide to rate design generally and revenue allocation specifically.[23]

Q. WHAT IS OSBA'S REBUTTAL TESTIMONY REGARDING YOUR PROPOSED REVENUE ALLOCATION?

A. OSBA Witness Ewen concludes that the ECOSS without minimum-size classification is not consistent with cost causation, and, therefore, OCA's proposed revenue allocation which is based on the ECOSS without minimum-size classification is not appropriate for this proceeding.[24]

Q. WHAT IS YOUR RESPONSE TO WITNESS EWEN'S REBUTTAL TESTIMONY?

A. In Section III.B.2 above I have demonstrated that witness Ewen's rebuttal testimony provides no convincing evidence that the ECOSS without minimum-size classification is not consistent with cost causation. Nor does his testimony provide convincing evidence that the ECOSS with minimum-size classification is consistent with cost causation. Thus, he does not provide convincing evidence that OCA's proposed revenue allocation is not appropriate for this proceeding.

[23] Pavlovic Direct, page 14 line 15 to page 16 line 11 (Table 2) and page 21 line 1 to page 22 line 1 (Tables 5 and 6).
[24] Ewen Rebuttal, page 3 lines 23-26.

Q. WHAT DO YOU CONCLUDE REGARDING OSBA WITNESS EWEN'S REBUTTAL TESTIMONY?

A. For the reasons give above I conclude that OSBA witness Ewen's rebuttal testimony provides no grounds for modification or withdrawal of my proposed class revenue allocation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement this testimony if further information is provided by PCLP or OSBA.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

VERIFICATION

I, Karl R. Pavlovic, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 15, 2025

Signature: */s/Karl R. Pavlovic*
Karl R. Pavlovic

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877