

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
CHRISTINE M. MARTIN
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Overview of Rebuttal Testimony
 Need for the Proposed Rate Increase**

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christine M. Martin. My business address is 827 Hausman Road, Allentown, PA 18104.

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

A. I am employed as the President of PPL Electric Utilities Corporation (“PPL Electric”), a subsidiary of PPL Corporation.

Q. Have you previously filed testimony in this matter?

A. Yes. I previously submitted direct testimony, PPL Electric Statement No. 1.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to provide an overview of the Company’s rebuttal testimony submitted in this proceeding by myself and other witnesses in support of PPL Electric’s proposed increase in base distribution rates of approximately \$356 million. In addition, I will respond to portions of the direct testimony submitted by the other parties as well as certain testimony offered at the public input hearings concerning: (1) the need for the proposed rate increase; (2) affordability; and (3) data centers.

1 **Q. How is the remainder of your rebuttal testimony organized?**

2 A. The first section provides an overview of the Company's rebuttal testimony submitted in this
3 proceeding. Next, I will reiterate the need for PPL Electric's first base rate increase in over
4 10 years and how the other parties' alternative proposed increases do not provide the
5 Company with a reasonable opportunity to earn a just and reasonable return of and on its
6 investments, while continuing to provide safe, reliable, adequate, efficient, and reasonable
7 electric distribution service. Also, in that same section, I will generally address the testimony
8 of other parties and members of the public concerning the affordability of PPL Electric's
9 electric service and the impact of data centers on customers' bills.

10
11 **Q. Before addressing those topics, do you have any initial observations regarding the other**
12 **parties' direct testimony and the Company's rebuttal testimony?**

13 A. Yes. As explained in the Company's rebuttal testimony, PPL Electric identified various
14 corrections to the figures in its initial filing that needed to be made, including approximately
15 \$34 million for the annual amortization of negative net salvage that was not included in the
16 Company's original calculation of its proposed increase in its revenue requirement. These
17 corrections were identified in the Company's discovery responses, namely its supplemental
18 response to OCA I-1 and OCA III-18. Collectively, these corrections showed that the
19 Company's original proposal for a base rate revenue increase should have been approximately
20 \$389 million, not the approximately \$356 million increase originally proposed.

21 Notably, multiple parties did not address these corrections in their direct testimony or
22 flow through these corrections to their own revenue models. Moreover, for the approximately

1 \$34 million annual amortization of negative net salvage, no party challenged PPL Electric
2 witness Spanos's calculation or presentation of that amount in his depreciation study for the
3 Fully Projected Future Test Year ("FPFTY"). As explained by PPL Electric witness Spanos,
4 that annual amortization of negative net salvage should be recovered as a part of the
5 Company's depreciation expense under well-established precedent.

6 PPL Electric recognizes that it cannot be awarded an increase in this proceeding of
7 more than the approximately \$356 million the Company requested in its initial filing.
8 However, these unchallenged corrections should be reflected in the other parties' calculation
9 of the components making up their proposed increases in the revenue requirement. At the
10 very least, these corrections are further evidence that the other parties' proposed base rate
11 increases will not provide the Company with a reasonable opportunity to earn a just and
12 reasonable return of and on its investments. In fact, as noted by PPL Electric witness Dane,
13 when reflecting these corrections in the other parties' proposed revenue increases, the
14 amounts would be as follows:

- 15 • I&E = \$294,217,000
- 16 • OCA = \$184,286,000

17 Thus, I urge the Commission to incorporate those corrections when evaluating the other
18 parties' positions on the proposed increase in the Company's distribution base rate revenues.

II. OVERVIEW OF REBUTTAL TESTIMONY

Q. Could you please provide an overview of the rebuttal testimony being submitted by witnesses on behalf of PPL Electric in this proceeding?

A. Yes. Below is a list of the rebuttal testimony being submitted in support of its proposed distribution base rate increase:

- PPL Electric St. No. 2-R – Dennis A. Urban, Jr. – Adjustments to Revenue Requirement; Bank Charges; Company Sponsorships; Membership Dues and Subscriptions; Payroll and Benefits Expense; Advertising Expense; Research and Development Expenses.
- PPL Electric St. No. 4-R – Charles R. Schram – Sales Forecast.
- PPL Electric St. No. 5-R – Bethany L. Johnson – FERC-Regulated Transmission Rates Versus Commission-Regulated Distribution Rates; Overall Revenue Requirement; Cost of Service and Rate Design; Rate Case Expense; Rate Case Filing and Notices; PPL Corp. Joint Venture with Blackstone.
- PPL Electric St. No. 6-R – Daniel S. Dane – Late Payment Revenues; O&M Expense Adjustments; Revenue Requirement; Taxes Other than Income Taxes; Interest Synchronization.
- PPL Electric St. No. 7-R – Bickey Rimal – Cost of Service; Rate Design.
- PPL Electric St. No. 8-R – Steven W. Wishart – Affordability; Rate Design; Standby Service.
- PPL Electric St. No. 9-R – Julissa Burgos – Embedded Cost of Capital; Capital Structure.
- PPL Electric St. No. 10-R – Jennifer E. Nelson – Return on Equity; Capital Structure.
- PPL Electric St. No. 11-R – John J. Spanos – Amortization of Net Salvage; Depreciation Service Lives.
- PPL Electric St. No. 12-R – Andrew Elmore – Payroll Taxes and Expenses; PURTA Tax; Interest Synchronization; Gross Receipts Tax.
- PPL Electric St. No. 13-R – Katelyn Arnold – Storm Damage Expenses; Cash Working Capital; Eligible Customer List Expenses.
- PPL Electric St. No. 14-R – Gregory Olsen – Retail Tariff; Interconnection Process;

Maximum Registered Peak Load.

- PPL Electric St. No. 15-R – Andrew Castanaro – Maximum Registered Peak Load; Value of EDI Transaction Information for Default Supply and Capacity Allocations.
- PPL Electric St. No. 16-R – Joseph Lookup – Large Load Interconnection; Reliability and Performance; Storm Restoration and Planning.
- PPL Electric St. No. 17-R – Nicole Howell – Vegetation Management.
- PPL Electric St. No. 18-R – Lisa Norden – Customer Service Performance; Low-Income Customer Issues; Payment Transaction Fees; Universal Service Programs; Supplier Tariff.
- PPL Electric St. No. 19-R – Daniel Johnson – IT Upgrades.
- PPL Electric St. No. 20-R – James Conrad – Affiliate Support-Engineering & Construction Expense; Electric Vehicles; Distributed Energy Resource Management System.
- PPL Electric St. No. 21-R – Jason Hunt – Economic Development.
- PPL Electric St. No. 22-R – Sharon Leskowsky – Adjustment to Depreciation Expense; Infrastructure Investment & Jobs Act (IIJA) Cost Amortization; Capitalization of Certain Vegetation Management Costs.
- PPL Electric St. No. 23-R – Vincent Poplaski – Incentive Compensation Expense.

Q. You mentioned previously that the Company had corrections to its as-filed base rate increase, which collectively resulted in an increase in annual base distribution revenues of approximately \$389 million instead of the as-filed approximately \$356 million increase. Are there any adjustments proposed by the other parties that the Company has accepted as part of its rebuttal case?

1 A. As part of its rebuttal case, PPL Electric is accepting, in whole or in part, adjustments to late
2 payment revenues, Eligible Customer List (“ECL”) expenses, payroll tax expenses, gross
3 receipts tax (“GRT”) gross-up value, and company sponsorships.

4
5 **Q. Could you please summarize what is the impact on PPL Electric’s proposed revenue**
6 **requirement due to the Company’s corrections and the other parties’ adjustments that**
7 **PPL Electric has accepted?**

8 A. As explained by PPL Electric witness Dane, PPL Electric’s proposed increase in its
9 distribution base rate revenues would be approximately \$384.5 million, after accounting for
10 the Company’s corrections along with the other parties’ recommended adjustments that the
11 Company is accepting as part of its rebuttal case.

12
13 **III. NEED FOR THE PROPOSED RATE INCREASE**

14 **Q. In this proceeding, concerns have been raised regarding the need for the Company’s**
15 **proposed increase in distribution base rates. (See, e.g., OCA St. 9, pp. 20-24.) Would**
16 **you please respond to those concerns?**

17 A. PPL Electric maintains that its proposed base rate increase should be approved. The Company
18 certainly is cognizant of the impact that its proposed base rate increase will have on its
19 customers’ bills. At the same time, however, this is PPL Electric’s first base rate case in over
20 10 years. Over that time, PPL Electric has been incredibly efficient at managing its operation
21 and maintenance (“O&M”) expenditures and leveraging its Distribution System Improvement
22 Charge (“DSIC”) to make capital investments in the repair and replacement of eligible

1 infrastructure in order to improve and maintain the safety and reliability of the Company's
2 electric distribution service. However, as noted above and in my direct testimony, PPL
3 Electric's existing base distribution rates do not provide the Company with a reasonable
4 opportunity to recover its prudently incurred expenses and earn a just and reasonable return
5 on its capital investments. Notably, the Commission's Bureau of Investigation and
6 Enforcement ("I&E") and the Office of Consumer Advocate ("OCA") agree that the existing
7 rates are deficient, with them proposing rate increases of approximately \$258.88 million and
8 \$150.04 million, respectively. Therefore, the question is not whether the Company should be
9 granted an increase in its base distribution rates, but rather the extent of that increase.

10 Here, the Company has identified flaws with other parties' arguments regarding the
11 proposed base rate increase, as outlined in PPL Electric's rebuttal testimony. Furthermore,
12 the Company's corrections to its initial filing show that PPL Electric should have requested
13 an increase of approximately \$389 million instead of the as-filed amount of approximately
14 \$356.27 million. Again, although the Company cannot be awarded more than its proposed
15 \$356.27 million increase, these corrections serve to reinforce the need for the Company's
16 proposed increase and further demonstrate that other parties' positions on the increase should
17 be rejected.

18
19 **Q. Questions have been raised about the need for the proposed base rate increase, based**
20 **on the "financial health" of PPL Electric's ultimate parent holding company, PPL**
21 **Corporation. (OCA St. 9, pp. 20-23; see also EJA St. No. 1, pp. 22, 29-30; CAUSE-PA**
22 **St. No. 1, pp. 17-20.) Could you please respond?**

1 A. PPL Electric is a subsidiary of PPL Corporation and, as an EDC in Pennsylvania, PPL
2 Electric is provided the opportunity to recover reasonable and prudent costs in a timely
3 manner; costs that are incurred by the utility to provide safe and reliable service. It should
4 be noted that PPL Corporation is the holding company for operations across 4 states –
5 Pennsylvania, Rhode Island, Kentucky, and Virginia – and is also able to engage in other
6 non-regulated opportunities, which are funded by shareholders. Just as other parties would
7 be the first to raise concerns if PPL Electric’s customers were asked to fund operations in
8 other states or shareholder activities, it is similarly not appropriate for PPL Corporation to
9 cover PPL Electric’s costs on the backs of customers in other jurisdictions or shareholders.

10 Further, the Federal Energy Regulatory Commission (“FERC”) has many rules about
11 affiliate support and investment. In fact, the Commission has also, in PPL Electric’s most
12 recent management efficiency investigation, recommended that the Company file its affiliate
13 financing arrangement with the Commission to ensure that the operating company is properly
14 financially protected.

15 Simply stated, PPL Electric is a regulated EDC that has submitted a distribution base
16 rate increase in accordance with the Pennsylvania Public Utility Code and the utility should
17 be duly awarded the opportunity to recover its costs associated with providing safe and
18 reliable service to approximately 1.5 million customers in the Commonwealth.

Q. Questions also have been raised about the affordability of PPL Electric’s electric service at existing and proposed rates. (See, e.g., OCA St. 8, pp. 7-40; OCA St. 9, pp. 2-8; CAUSE-PA St. No. 1, pp. 4-6, 31-48; EJA St. No. 1, pp. 8-18.) Does the Company place an emphasis on the affordability of its electric distribution service?

A. Absolutely. PPL Electric takes its statutory duty to provide safe, reliable, adequate, and efficient electric service at reasonable rates seriously. To that end, PPL Electric strives to be judicious with its O&M and capital expenditures, recognizing the downstream impact the incurrence of those costs has on customers’ rates. That keen focus has led to the Company having among some of the lowest electric distribution rates among the major electric distribution companies (“EDCs”) even with the proposed base rate increase, as shown in the following table.

Typical Bills and Average Rates Report						
Rates in effect July 1, 2025 and average revenue data from the year preceding July 1, 2025						
	Residential 1,000 kWh		Commercial 1,500 kWh		Industrial 75kW / 15,000 kWh	
	<u>PPL Electric</u>	<u>PA Average</u>	<u>PPL Electric</u>	<u>PA Average</u>	<u>PPL Electric</u>	<u>PA Average</u>
Delivery	\$66.77	\$87.03	\$29.00	\$101.00	\$400.00	\$993.00
Total Rate	\$191.67	\$201.91	\$210.00	\$269.00	\$2,217.00	\$2,284.00

Source: Edison Electric Institute; Revised Summer 2025 Typical Bills and Average Rates report

Moreover, PPL Electric offers a series of customer assistance programs under its Universal Service and Energy Conservation Plan (“USECP”) and Act 129 Energy Efficiency and Conservation (“EE&C”) Plan that are designed to help customers reduce their energy usage and bills. While those programs are required by law, PPL Electric places a substantial focus on making those programs operate as effective as reasonably possible within their established budgets.

1 Over the last decade, during which the Company has not sought any base rate increase,
2 PPL Electric has utilized all available tools in consideration of customer affordability. In the
3 face of reliability concerns, the Company has increased its LTIP spend and was approved for
4 a waiver of its DSIC cap. This gave the Company the opportunity to make significant
5 reliability investments and mitigate rate shock for customers, while also continuing to
6 maintain consumer protections with a price cap. This serves as evidence that the Company
7 has explored and utilized available options before seeking the instant base distribution rate
8 increase.

9 Finally, the Company recognizes that parties have raised concerns about the proposed
10 base rate increase's impact on low-income and payment troubled customers, particularly the
11 alleged impact of the proposed increase in the fixed residential customer charge. However,
12 as explained by PPL Electric witness Wishart, low-income customers are not synonymous
13 with low-usage customers. In fact, the Company's data shows that low-income customers
14 generally use as much electricity as, and often more electricity than, the average residential
15 customer, for both electric-heating and non-electric-heating. Therefore, by moving more of
16 the bill to the fixed charge, there would be high-usage low-income customers that are better
17 insulated from the proposed base rate increase than if the Company's fixed residential
18 customer charge were to remain the same or be decreased, as advocated by certain parties.
19 (See OCA St. 4, pp. 38-39; CAUSE-PA St. No. 1, p. 28; CEO St. No. 1, pp. 4-5; EJA St. No.
20 1, pp. 6, 44-45.)

1 **Q. Other testimony has focused on data centers and the impact that they have on**
2 **customers' electric rates, with even some members of the public alleging that the**
3 **proposed increase in PPL Electric's distribution base rates is driven to data centers, as**
4 **opposed to the Company's investments in safety and reliability of its distribution system.**
5 **(See, e.g., OCA St. 5, pp. 6-64; OCA St. 9, pp. 8-15; OSBA St. No. 1, pp. 15-16; CAUSE-**
6 **PA St. No. 1, pp. 94-95; CAUSE-PA St. No. 2, pp. 3-25; EJA St. No. 1, pp. 16, 74-79; EI**
7 **St. No. 1, pp. 6-45.) Please respond.**

8 **A.** As explained in more detail by PPL Electric witness Bethany Johnson, this case involves the
9 Company's distribution rates that are subject to the Commission's jurisdiction, not its
10 transmission rates that are regulated by FERC. This distinction is important because the data
11 centers interconnecting with PPL Electric are taking service at transmission-level voltage.
12 Nearly all of their electric bills consist of transmission charges, not distribution charges.
13 Indeed, because they do not connect to distribution-level voltage facilities, the only
14 distribution charge they pay is to cover the costs of metering and billing. Accordingly, none
15 of the capital investments that are driving the distribution base increase are to pay for data
16 center interconnections. Such costs, to the extent any are or will be incurred, are recovered
17 through the Company's FERC-approved transmission rates, which are outside the scope of
18 this proceeding.

19 Separately, though the impact that data centers may have on the transmission system
20 and transmission capacity are addressed through FERC, it should be noted that while the
21 Company recognizes the impacts that data centers may have on *generation* capacity and
22 *energy* availability, those issues are also outside the scope of this distribution base rate case.

1 Because Pennsylvania was restructured in the late 1990's, the Company is severely limited in
2 its ability to materially affect the availability and cost of generation resources available to its
3 customers without legislative changes. As such, this distribution base rate request by PPL
4 Electric seeking to recover costs for distribution system operations should not be undermined
5 by current energy policy, especially given the Company's consideration of affordability and
6 actions to mitigate customer costs as discussed earlier in my rebuttal testimony. Under current
7 Pennsylvania law, the Electric *Distribution* Company has an obligation to provide safe and
8 reliable service and is seeking the instant increase to support that. Data centers are not a user
9 of the distribution system, let alone a driver, and so are not a driver of the Company's request.
10 Both Mr. Lookup and Ms. Johnson provide further details on this matter in their rebuttal
11 testimony.

12 Thus, as I previously testified, the Company's principal reasons for filing the base rate
13 case include: (1) little to no growth in customers or sales due to slow economic growth and
14 increased distributed generation; (2) increased capital investment that is necessary to maintain
15 and improve system reliability, such as an additional \$4 billion in capital investments in the
16 distribution system from 2025-2029 that will include additional storm hardening measures to
17 strengthen the distribution system, protect against increasing weather-related outages, and
18 improve customer experience; (3) the Company's commitment to providing the highest
19 quality, safe, and affordable service to its customers; (4) the Company's significant
20 Information Technology ("IT") infrastructure investments that are designed to, among other
21 things, provide long-term security and stability to PPL Electric's IT infrastructure and enhance

customer experience; and (5) the need to set rates based on the full class cost of service. (See PPL Electric St. No. 1, pp. 15-16.)

Q. Does the Company recognize the impact that data centers may nonetheless have on customers' electric bills?

A. Yes, and that is why, as explained by PPL Electric witness Lookup, the Company proposed revisions to its Rate Schedule LP-5 to protect customers against the potential risks associated with large load interconnections, including data centers. The Company also has thoroughly evaluated other parties' proposals concerning the Company's large load tariff. As noted by Mr. Lookup in his rebuttal testimony (PPL Electric St. No. 16-R), PPL Electric is willing to make the following changes to its proposal:

- Create a new LP-6 rate class for customers with peak demands of 75 MW and above;
- 10 year minimum term for ESAs;
- Revise minimum load guarantee to 80% for first five years, 50% for second five years of initial term;
- Exit fee equal to the remaining minimum load guarantee obligation during the ESA term;
- PPL Electric will submit ESAs, CSAs, and a breakdown of the allocation of system upgrade costs to the PUC for transparency and information (not approval);
- Offer a voluntary interruptible option, which if chosen would reduce the minimum load guarantee to 60% for the first five years, and 30% for the second five years;

- PPL Electric will submit annual load forecasts to the PUC including a breakdown of requests of customers with ESAs, LOAs, and inquiries; and
- LP-6 rate class will be allocated \$10 million of USR costs annually with the \$10 million to be allocated amongst the class.

Lastly, it should be noted that, as discussed in my direct testimony and Mr. Lookup's direct testimony (PPL Electric St. No. 16) and as further explained in Ms. Johnson's rebuttal testimony (PPL Electric St. No. 5-R), data center load growth is expected to reduce transmission costs, even if the data centers are shopping customers. The decrease in transmission cost component for a default service residential customer using 1,000 kWh is anticipated to be approximately \$40/year with the addition of 1 GW of load, and the savings continue to increase with additional data center load.

IV. CONCLUSION

Q. Please summarize your rebuttal testimony.

A. In conclusion, PPL Electric's proposed distribution rate increase is both reasonable and firmly supported by the record. The Company has thoroughly evaluated the concerns raised by other parties. Opposing parties' recommendations and assertions rely on incomplete or inaccurate assumptions—particularly with respect to baseline revenue requirements, jurisdictional distinctions between state and federal oversight, and purported distribution system impacts associated with emerging large-load customers such as data centers.

When the appropriate corrections and clarifications are applied, the Company's proposed distribution base rate increase is clearly just and reasonable and in the best interests

1 of PPL Electric's customers and the communities it serves.

2

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

4 A. Yes, it does.

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John Gadomski	:	C-2025-3059330
	:	
v.	:	
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PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
DENNIS A. URBAN, JR.
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Adjustments to Revenue Requirement**
 Bank Charges
 Company Sponsorships
 Membership Dues and Subscriptions
 Payroll and Benefits Expense
 Advertising Expense
 Research and Development Expenses

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis A. Urban, Jr., and my business address is 645 Hamilton Street, Suite 9, Allentown, PA 18101.

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

A. I am employed by PPL Services Corporation (“PPL Services”), a subsidiary of PPL Corporation and an affiliate of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”). I hold the position of Senior Director, Finance Transformation.

Q. Have you previously filed testimony in this matter?

A. Yes, my direct testimony in this matter is PPL Electric Statement No. 2.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the Company’s adjustments to the Company’s revenue requirement and to respond to adjustments and recommendations regarding the Company’s Bank Charges, Company Sponsorships, Membership Dues and Subscriptions, Payroll and Benefits Expense, Advertising Expense, and Research and Development. These adjustments and recommendations were put forth by one or more of the following: the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation and Enforcement (“I&E”) Witnesses Zachari Walker (I&E St. No. 1),

Christopher Keller (I&E St. No. 2), and Ethan Cline (I&E St. No. 4); and Office of Consumer Advocate (“OCA”) Witness Lafayette Morgan (OCA St. 1).

Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?

A. Yes. Attached to my rebuttal testimony are the following exhibits:

- PPL Electric Exhibit DAU-1R – Answer to OCA I-1 SUPPLEMENTAL
- PPL Electric Exhibit DAU-2R – OCA I-1 Attachment 231 SUPPLEMENTAL
- PPL Electric Exhibit DAU-3R – Answer to I&E-RE-I-2-D
- PPL Electric Exhibit DAU-4R – Answer to OCA XXV-9
- PPL Electric Exhibit DAU-5R – Answer to I&E-RE-I-12-D
- PPL Electric Exhibit DAU-6R – Answer to OCA XII-11
- PPL Electric Exhibit DAU-7R – Answer to OCA XXV-23
- PPL Electric Exhibit DAU-8R – Answer to I&E-RE-II-17-D
- PPL Electric Exhibit DAU-9R – Updated PPL Electric Exhibit DAU-2

In addition, I am sponsoring or co-sponsoring Schedules B-1, B-2, B-4, and D-5 of PPL Electric Rebuttal Exhibit No. 1. Further, as stated in my direct testimony and as noted above, I am providing an updated version of PPL Electric Exhibit DAU-2.

1 **II. ADJUSTMENTS TO REVENUE REQUIREMENT MADE IN DISCOVERY**

2 **Q. Did the Company identify any adjustments to the revenue requirement provided in its**
3 **initial rate case filing during the discovery process?**

4 A. Yes. The Company provided an update to its revenue requirement, which is explained in
5 OCA I-1 SUPPLEMENTAL and illustrated in OCA I-1 Attachment 231 SUPPLEMENTAL,
6 both attached as PPL Electric Exhibits DAU-1R and DAU-2R, respectively. As explained in
7 that discovery response, this updated calculation includes four adjustments. First, the
8 Company corrected its reported operation and maintenance (“O&M”) expenses to reflect an
9 updated value for its membership dues in the Fully Projected Future Test Year (“FPFTY”).
10 Secondly, the Company adjusted its calculation of base distribution revenue to remove the
11 State Tax Adjustment Surcharge (“STAS”) – Distribution amount from base distribution
12 revenues. Third, the depreciation adjustment provided in PPL Electric Exhibit Fully Projected
13 Future 1, Schedule D-15, was updated to include the net salvage amount in the depreciation
14 adjustment, which was inadvertently excluded from the D-15 adjustment in the initial filing
15 but was included in PPL Electric Exhibit JJS-3. This is further discussed in the rebuttal
16 testimony of PPL Electric Witness Spanos (PPL Electric St. No. 11-R) and PPL Electric
17 Witness Leskowsky (PPL Electric St. No. 22-R). Fourth, the Company updated its cash
18 working capital calculation based on an update to the Historic Test Year (“HTY”) D-1
19 Schedule, which impacted the calculation to the average lag in days between payment of
20 O&M expenses and receipt of revenue value, which flowed through to the Future Test Year
21 (“FTY”) and the FPFTY. This is further explained in the discovery response to I&E-RE-I-2-
22 D, attached as PPL Electric Exhibit DAU-3R.

III. BANK CHARGES

Q. How does I&E Witness Walker summarize the Company's claim regarding bank charges?

A. I&E Witness Walker testifies that the Company has "identified its FPFTY claim of \$900,000 for outside service employed costs related to bank charges." He goes on to note that "the bank charges represent costs incurred for the Company's financing activities, allocated based on historical allocation percentages as provided in filing requirement II-D-8 of the Company's Cost Allocation Manual." (I&E St. No. 1, p. 18.)

Q. What does I&E Witness Walker recommend?

A. He recommends an allowance of \$512,000 (i.e., reduction of \$388,000) based on a 3-year historical net average of the bank charges incurred and any credits received. (I&E St. No. 1, p. 19.) As alleged support for his recommendation, Mr. Walker argues that the Company "does not explicitly state" that it is using historical data, nor does the Company "identify the payees on which its FPFTY bank charges expense claim is based." (I&E St. No. 1, p. 20.) He also asserts that the Company has not fully supported its FPFTY bank charges expense claim, so the 3-year historical average of the net bank charges produces a "more reasonable expense level" which produces his recommended allowance of \$512,000 to the Company's FPFTY claim. (I&E St. No. 1, p. 20.)

Q. Do you agree with this recommendation?

A. No. PPL Electric supported its claim in response to OCA XXV-9, attached as PPL Electric Exhibit DAU-4R. In that response, it stated that bank charges were determined by analyzing the prior year's fees and adjusting for any increased volumes and fees, where applicable. That response also included a list of banks and forecasted bank charges for the FTY and FPFTY, which are also listed in the table below. A simple 3-year average of historic amounts is not always the best estimate to use, as it is necessary to consider other factors like trends and emerging business needs. Furthermore, the Company's proposed rates are based upon the FPFTY. The forward-looking nature of ratemaking in this case demands that PPL Electric's projection of these expenses, which reflected this upward trend, should be utilized as opposed to Mr. Walker's proposed three-year average.

Banks and Forecasted Charges:

Bank	FTY	FPFTY
US Bank	\$ 22,265	\$ 22,000
Bank of America	7,042	7,000
Well Fargo	80,660	82,341
BNYM	688,055	704,500
CIBC	333	333
BNYM	51,742	52,957
Total	<u>\$ 850,097</u>	<u>\$ 869,131</u>

1 **IV. COMPANY SPONSORSHIPS**

2 **Q. How does I&E Witness Walker summarize the Company’s claim regarding Company**
3 **Sponsorships?**

4 A. He notes the FPFTY claim of \$28,000, going on to note that the Company maintains that these
5 costs are “reasonable and prudent because they are strategic investments in the community.”
6 (I&E St. No. 1, pp. 20-21.)

7
8 **Q. What does I&E Witness Walker recommend?**

9 A. He recommends the entire \$28,000 claim be disallowed for ratemaking purposes. (I&E St.
10 No. 1, p. 21.) He reasons that: (1) the Lehigh Valley Iron Pigs costs do not qualify for recovery
11 under 66 Pa. C.S. § 1316.1; (2) payments to Greater Lehigh Valley (“GLV”) Chamber and
12 Lehigh Valley Economic Development Corporation (“LVEDC”) are not necessary for the
13 reliable and safe provision of utility service and do not directly benefit PPL Electric’s
14 ratepayers; and (3) contributions to Lehigh Valley Community Foundation (“LVCF”) are not
15 necessary for the reliable and safe provision of utility service and do not directly benefit PPL
16 Electric’s ratepayers. (I&E St. No. 1, pp. 21-24.)

17
18 **Q. Please respond to this recommendation.**

19 A. Mr. Keller’s recommended disallowance of \$28,000 is rounded. However, PPL Electric does
20 not oppose the disallowance of \$27,510 as stated in response to I&E-RE-I-12-D attached as
21 PPL Electric Exhibit DAU-5R.

22

1 **Q. What does OCA Witness Morgan recommend regarding Company Sponsorships?**

2 A. He recommends a disallowance of \$120,000 on the basis that, like Goodwill and Corporate
3 Image Advertising, Company sponsorships do “virtually nothing” to assist in providing safe
4 and reliable service to ratepayers. (OCA St. 1, p. 19.)
5

6 **Q. Do you agree with this recommendation?**

7 A. No. Foremost, Mr. Morgan incorrectly used the HTY amount of \$120,000 as the basis for
8 disallowance. The FPFTY claim stated on I&E-RE-I-12-D is actually \$27,510, as reflected
9 in the Company’s revenue requirement. However, as noted above, PPL Electric does not
10 oppose the disallowance of the \$27,510 of the Company Sponsorships claim.
11

12 **V. MEMBERSHIP DUES AND SUBSCRIPTIONS**

13 **Q. How does I&E Witness Walker summarize the Company’s claim regarding**
14 **Membership Dues and Subscriptions?**

15 A. He asserts that the claim for Membership Dues and Subscriptions is \$2,800,000, describing
16 the basis for the claim as “includ[ing] costs incurred and associated with memberships to
17 chambers of commerce, employee training and professional development organizations,
18 industry groups and associations, work-related travel, and online working tools, among other
19 things. (I&E St. No. 2, pp. 24-25.)
20

1 **Q. Is this a fair summary of the Company's claim?**

2 A. No, in response to OCA XII-11, attached as PPL Electric Exhibit DAU-6R, PPL Electric
3 found a timing item of approximately \$800,000. After this adjustment, PPL Electric's claim
4 for Membership Dues and Subscriptions is approximately \$2,000,000, not \$2,800,000.

5
6 **Q. What does I&E Witness Walker recommend?**

7 A. He recommends that the Commission disallow \$2.8 million in Membership Dues expense.
8 (I&E St. No. 1, p. 25.) It should be noted that the Company revised its claim to \$2.0 million,
9 further disputing I&E Witness Walker's adjustment. In support of this recommendation, he
10 alleges that the claim is unsupported, pointing to discovery response to I&E-RE-I-12-D and
11 says that "it is unclear what amounts and corresponding payees are included in the Company's
12 FPFTY claim." (I&E St. No. 1, pp. 25-26.) He also discusses the Columbia Gas 2025 Rate
13 Case decision, which denied recovery of chamber of commerce fees in base rates. (I&E St.
14 No. 1, p. 26.)

15
16 **Q. Do you agree with this recommendation?**

17 A. No. PPL Electric, in response to I&E RE I-12-D, provided historic detail that was the basis
18 for its claim. Though I do not agree with using Mr. Walker's simple three-year average as he
19 proposed related to bank charges, it would at least provide an amount of approximately
20 \$1,700,000 for Membership Dues and Subscriptions, not accounting for other variables.

21 Further, in reviewing the details provided in response to I&E RE I-12-D, PA Chamber
22 fees for the HTY and the previous two years amount to \$19,800, \$76,100, and \$2,592

1 respectively. If the Commission were to disallow the Chamber of Commerce fees as they did
2 in the Columbia Gas 2025 Rate Case decision, the inclusion of these amounts in historic
3 periods does not warrant disallowing recovery of all membership dues and subscriptions fees.
4 Other dues regarding employee training and professional development organizations, industry
5 groups and associations, work-related travel, and online working tools are a necessary part of
6 running a regulated utility effectively.

7
8 **Q. Does OCA Witness Morgan make any recommendations related to Membership Dues**
9 **and Subscriptions?**

10 A. Yes. OCA Witness Morgan recommends decreasing the claim by \$808,000 based on the error
11 identified in the responses to OCA XII-11, provided in this proceeding in OCA Exhibit LMK-
12 10.

13
14 **Q. Do you agree with this recommendation?**

15 A. In part. The Company agrees with making this adjustment but agrees to do so in the exact
16 amount of the overstatement, which is \$808,339. This was updated in discovery and is
17 provided in the discovery response to OCA I-1 SUPPLEMENTAL, attached as PPL Electric
18 Exhibit DAU-1R, and OCA I-1 Attachment 231 SUPPLEMENTAL, attached as PPL Electric
19 Exhibit DAU-2R.

20

VI. PAYROLL AND BENEFITS EXPENSE

Q. How does I&E Witness Keller summarize the Company's Payroll and Benefits Expense?

A. I&E Witness Keller notes that the Company's claim for payroll expenses is \$64,357,000 while the claim for benefits expense is \$17,543,000. (I&E St. No. 2, pp. 3-4, 10.)

Q. Does I&E Witness Keller agree with the Company's claim?

A. He does not.

Q. What does I&E Witness Keller recommend?

A. He recommends an allowance of \$76,479,000 for payroll and benefits expense, which is a reduction of \$5,421,000 to the Company's claim. (I&E St. No. 2, p. 4.) He also notes that he will recommend rejecting recovery of \$1,400,000 payroll expense related to employees that administer the Company's Universal Service Programs through the Universal Service Rider ("USR"). (I&E St. No. 2, p. 4.)

Q. What is the basis for this recommendation?

A. Mr. Keller bases this recommendation on a vacancy adjustment, arguing that it is not reasonable to assume the Company will maintain 100% full staffing based on its vacancy records. He assumes that there is a certain level of vacancies on a day-to-day basis, claiming this reflects a more accurate employee complement in the FPFTY. (I&E St. No. 2, pp. 4-5.) Mr. Keller explains that he "determined the adjustment based on a three-year average vacancy

1 rate and applied this to the Company's claim for payroll and benefits." (I&E St. No. 2, p. 5.)
2 He also claims that in the Company's response to I&E-RE-II-3-D, it "did not incorporate a
3 general vacancy reserve when developing its claim for payroll and benefits expense." (I&E
4 St. No. 2, p. 5.) Moreover, he avers that PPL Electric stated, "that head count is done at the
5 functional group level where some functional groups apply a 5% vacancy reserve, but the
6 Company did not provide any calculations to reflect any vacancy reserve for those functional
7 groups." (I&E St. No. 2, pp. 5-6.) Consequently, he recommends a vacancy rate of 4.3%
8 union and 10.3% non-union payroll and benefits expense. (I&E St. No. 2, p. 6.)
9

10 **Q. How does I&E Witness Keller calculate his payroll expense vacancy adjustment?**

11 A. Mr. Keller determined a three-year average vacancy rate for union and non-union personnel
12 as provided in response I&E-RE-II-2-D. He then calculated a ratio between union and non-
13 union wages using data from response I&E-RE-II-1-D and applied that to the payroll claim
14 to split it into two buckets. Lastly, he applied the resulting vacancy rate to the resulting union
15 and non-union buckets.
16

17 **Q. How does I&E Witness Keller calculate his benefits expense vacancy adjustment?**

18 A. Similar to his methodology to calculate an implied vacancy rate, Mr. Keller calculated a
19 percentage of union and non-union benefit costs and applied those percentages to the benefit
20 expense claim. He then applied his calculated vacancy rates to those amounts.
21

1 **Q. Do you agree with his calculations and recommendations?**

2 A. No.

3
4 **Q. Why not?**

5 A. Mr. Keller does not account for the 5% vacancy reserve already included by the Company for
6 certain functional groups as stated in response to OCA XXV-23. (See PPL Electric Exhibit
7 DAU-7R [Answer to OCA XXV-23].) He also fails to factor in the more expensive temporary
8 contractors that would be hired if the Company does not timely fill certain positions. Staffing
9 levels are needed to effectively manage and maintain PPL Electric's system to meet customer
10 needs and will be balanced with external resources if internal positions are not filled.

11
12 **Q. Does OCA Witness Morgan make any adjustments to the payroll expense for customer**
13 **service employees?**

14 A. Yes, Mr. Morgan adjusts payroll expenses based on an adjustment to the number of new
15 customer service employees to reflect 12 employees. (OCA St. 1, p. 8.)

16
17 **Q. Do you agree with this proposed adjustment?**

18 A. No. The Customer Service functional group applied a 5% vacancy reserve on its payroll
19 expense. A 48% reduction also does not factor in that if these new employees were not hired
20 in the expected period, contractors could support this customer service effort. The O&M costs
21 of those contractors would exceed the payroll expenses for these 12 employees included in

1 the Company's FPFTY claim, further demonstrating that the Company's expense claim is
2 reasonable.

3
4 **VII. ADVERTISING EXPENSE**

5 **Q. What does I&E Witness Keller recommend with respect to the Company's advertising**
6 **expense claim?**

7 A. He recommends an allowance of \$793,000 for advertising expense, which is a reduction of
8 \$130,000 to the Company's claim of \$923,000. (I&E St. No. 2, p. 21.)

9
10 **Q. What is the basis for this recommendation?**

11 A. Mr. Keller bases this recommendation on the removal of goodwill and institutional
12 advertising. (I&E St. No. 2, p. 21.) He calls out the type of advertising related to the
13 Company's Partners in Power campaign which, states "aims to build trust and community that
14 is rooted in partnership" where the purpose is to "reach broad audiences with emotionally
15 resonant stories" that offer "high reach, strong emotional impact, [and] credibility." (I&E St.
16 No. 2, pp. 21-22 (quoting response to I&E-RE-II-17-D).) He argues such advertising has little
17 to no benefit for ratepayers. (I&E St. No. 2, p. 22.)

18
19 **Q. Does OCA Witness Morgan similarly make any recommendations regarding the**
20 **advertising expenses?**

21 A. Yes, Mr. Morgan recommends a \$130,000 disallowance of the goodwill and institutional
22 advertising because "[a]dvertisements that depict the Company as being a good corporate

1 citizen serve only to benefit the Company's image for the purpose of making PPL a more
2 attractive investment option, and, therefore, it is more appropriate for shareholders to bear
3 those costs." (OCA St. 1, pp. 11-12.)
4

5 **Q. Do you agree with these recommendations?**

6 A. No. Mr. Keller does not provide the full description of the Partners in Power Campaign as
7 provided in PPL Electric's response to I&E-RE-II-17-D, a copy of which is attached as PPL
8 Electric Exhibit DAU-8R. The full description of the campaign explains that through its
9 Partners In Power campaign, PPL Electric aims to build trust and community connection that
10 is rooted in partnership by demonstrating the value behind investments that help safeguard
11 reliability and build communities that thrive as well as to provide support through available
12 tools, programs and resources that help them take control of their energy usage and manage
13 their bills, this campaign is the key mechanism to reach customers. As stated, these materials
14 promote tools and programs for customers to manage their bills and be efficient in their
15 electric usage and therefore benefit ratepayers and educate them on the resources available.
16

17 **VIII. RESEARCH AND DEVELOPMENT ("R&D") EXPENSES**

18 **Q. Does OCA Witness Morgan make a recommendation regarding the Company's claim**
19 **for R&D expense?**

20 A. Yes, OCA Witness Morgan recommends a decrease in the R&D expenses by \$321,000, which
21 is the full amount of the increase. (OCA St. 1, p. 17.)
22

1 **Q. How does OCA Witness Morgan try to justify this recommendation?**

2 A. Mr. Morgan claims that PPL Electric has not explained the cause of the increases, nor why
3 they are necessary for “safe and adequate” utility service. (OCA St. 1, p. 17.) He requests
4 that PPL Electric more fully explain the Internal R&D activities in rebuttal by fully explaining
5 why more coordination and participation with the Transmission and Distribution (“T&D”)
6 businesses would result in an increase in expenses of \$121,000 and further requests that the
7 Company more fully explain its increases in R&D expenses in rebuttal by providing the
8 budget justification for the increased National Electric Energy Testing, Research, and
9 Application Center (“NEETRAC”) expenditure and the benefits to ratepayers from the
10 NEETRAC research. (OCA St. 1, p. 17.)

11
12 **Q. Do you agree with this recommendation?**

13 A. No. R&D activities, such as those undertaken in the NEETRAC research, are needed to adapt
14 to industry changes, find lower cost solutions, and drive innovation in grid modernization for
15 improved reliability, safety and efficiency. In fact, PPL Electric has gained access to
16 resources to improve safety, reliability, affordability, and resiliency. These resources include,
17 but are not limited to, projects with the Electric Power Research Institute (“EPRI”) that
18 address data center integration, climate resiliency, and transmission system and distribution
19 system innovation. These additional resources will be used across PPL Electric and require
20 more coordination and participation with the Company’s Operations departments.
21 NEETRAC is an organization that helps address emerging electric grid challenges. This
22 center provides a platform for research and knowledge sharing. PPL Electric anticipates a

1 first quarter 2026 engagement with NEETRAC for these services in its forecast. Based on
2 the test year periods in this case, this provides 6 months of cost in FTY and 12 months in
3 FPFTY. The forecasted amount is \$100,000 per quarter.

4
5 **IX. CONCLUSION**

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

7 **A.** Yes, it does.

WITNESS: Various

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Office of Consumer Advocate (OCA)
Dated October 24, 2025
Docket No. R-2025-3057164

OCA I-1

Please provide all workpapers, in Microsoft Excel with all formulae intact, used in the preparation of and supporting the testimonies and exhibits of Company witnesses. This specifically includes all accounting schedules and related workpapers filed and the workpapers provided in response to discovery. Please provide files with all formulae intact and provide any linked files.

PPL Electric
Response

- PPL 2025 Rate Case – PPL Electric St. No. 1 (C. Martin)
 - No additional attachments included.
- PPL 2025 Rate Case – PPL Electric St. No. 2 (D. Urban)
 - See OCA I-1 Attachments 205 through 226.
- PPL 2025 Rate Case – PPL Electric St. No. 3 (C. Garrett)
 - See OCA I-1 Attachment 55.
- PPL 2025 Rate Case – PPL Electric St. No. 4 (C. Schram)
 - See OCA I-1 Attachments 170 through 178.
- PPL 2025 Rate Case – PPL Electric St. No. 5 (B. Johnson)
 - No additional attachments included.
- PPL 2025 Rate Case – PPL Electric St. No. 6 (D. Dane)
 - See OCA I-1 Attachments 17 through 34.
- PPL 2025 Rate Case – PPL Electric St. No. 7 (B. Rimal)
 - See OCA I-1 Attachments 154 through 169.
 - To support document links, the file names have been maintained. Attachment titles are:
 - OCA I-1 Attachment 154 Rimal: 2025 Rate Case COS - FTY and FFTY Revised 8-8-25 (GRSWRTOFF)
 - OCA I-1 Attachment 155 Rimal: 2025_08_08_Rate_Case_Calculation_CEA (Demand)
 - OCA I-1 Attachment 156 Rimal: Annualization - HTY FTY & FPFTY as of 8-18-25 (REV-ANNUALIZATION)
 - OCA I-1 Attachment 157 Rimal: COS 1-7 FTY_FPFTY Customer Deposits - Final (Deposit)

WITNESS: Various

- OCA I-1 Attachment 158 Rimal: COS 1-13
FTY_FPFTY Late Payments Final (LTFEES)
- OCA I-1 Attachment 159 Rimal: COS Revenue
FPFTY - Final (REV)
- OCA I-1 Attachment 160 Rimal: COS_1-3_&_1-
10_&_1-42_&_1-15-HTY_FTY_FFTY (Billing
Determinants)
- OCA I-1 Attachment 161 Rimal: Meter_Study (Meter
Costs)
- OCA I-1 Attachment 162 Rimal: Pole_Study
- OCA I-1 Attachment 163 Rimal:
PPL_Conductor_Study
- OCA I-1 Attachment 164 Rimal:
PRI_SEC_MIN_SYS_Summary
- OCA I-1 Attachment 165 Rimal: Retail External
Allocators
- OCA I-1 Attachment 166 Rimal: Rider Revenue for
FPFTY - DSIC SMR TCJA CER 9-5-25 (REV)
- OCA I-1 Attachment 167 Rimal: RR to COS
- OCA I-1 Attachment 168 Rimal:
Service_Wire_Installation_Data - Updated by MDH
Rev 2 (Service Costs)
- OCA I-1 Attachment 169 Rimal: Transformers_Study
- PPL 2025 Rate Case – PPL Electric St. No. 8 (S. Wishart)
 - See OCA I-1 Attachment 227.
- PPL 2025 Rate Case – PPL Electric St. No. 9 (J. Burgos)
 - No additional attachments included.
- PPL 2025 Rate Case – PPL Electric St. No. 10 (J. Nelson)
 - See OCA I-1 Attachments 108 through 113.
- PPL 2025 Rate Case – PPL Electric St. No. 11 (J. Spanos)
 - See OCA I-1 Attachments 179 through 204.
- PPL 2025 Rate Case – PPL Electric St. No. 12 (A. Elmore)
 - See OCA I-1 Attachments 35 through 54.
- PPL 2025 Rate Case – PPL Electric St. No. 13 (K. Arnold)
 - See OCA I-1 Attachments 1 through 13.
- PPL 2025 Rate Case – PPL Electric St. No. 14 (G. Olsen)
 - See OCA I-1 Attachments 145 through 153.
- PPL 2025 Rate Case – PPL Electric St. No. 15 (A.
Castanaro)
 - See OCA I-1 Attachments 14 through 16.
- PPL 2025 Rate Case – PPL Electric St. No. 16 (J. Lookup)
 - No additional attachments included.
- PPL 2025 Rate Case – PPL Electric St. No. 17 (N. Howell)

WITNESS: Various

- No additional attachments included.
- PPL 2025 Rate Case – PPL Electric St. No. 18 (L. Norden)
 - See OCA I-1 Attachments 114 through 116, 118 through 120, and 126 through 144.
 - See OCA I-1 CONFIDENTIAL Attachments 117 and 121 through 126.
- PPL 2025 Rate Case – PPL Electric St. No. 19 (D. Johnson)
 - See OCA I-1 Attachment 228.
- PPL 2025 Rate Case – PPL Electric St. No. 20 (J. Conrad)
 - No additional attachments included.
- PPL 2025 Rate Case – PPL Electric St. No. 21 (J. Hunt)
 - See OCA I-1 Attachment 56.
- PPL 2025 Rate Case – PPL Electric St. No. 22 (S. Leskowsky)
 - See OCA I-1 Attachments 57 through 107.

During the process of compiling this response, errors were identified in the original response to Filing Requirement II-D-3 and Filing Requirement II-D-7.

A revised II-D-3 is provided in OCA-I-Attachment 79 Leskowsky II-D-3 REVISED and a revised II-D-7 is provided in OCA-I-Attachment 78b Leskowsky II-D-7d - REVISED 11-10-25.

Note that OCA-I-1 Attachment 87a Leskowsky Schedule II-D-7 Attachment d REVISED 11.10.25 provides the workpapers for the revised II-D-7 schedule, while OCA-I-1 Attachment 87 Leskowsky Schedule II-D-7 Attachment d provides the workpapers for the initial as-filed II-D-7 schedule.

Supplemental Response (12-8-2025)

See OCA I-1 Attachment 229 Arnold SUPPLEMENTAL and OCA I-1 Attachment 230 Arnold SUPPLEMENTAL for the workpapers supporting PPL Electric Exhibit II-B-4.

See OCA I-1 Attachment 231 SUPPLEMENTAL for the following revised PPL Electric Exhibit Fully Projected Future 1 schedule revisions:

1. Revised PPL Electric Exhibit Fully Projected Future 1 Schedules B-2 and B-4 reflective of a reduction in O&M expense in the budget of \$808,339 as described in the response to OCA XII-11.

WITNESS: Various

2. Revised PPL Electric Exhibit Fully Projected Future 1 Schedule D-3 page 1 reflective of an adjustment to remove the STAS – Distribution and STAS – Energy & Transmission rider revenue amount of \$(4,707,032) as rider revenue in column 2 line 4. Only the STAS – Energy & Transmission rider revenue amount of \$(12,341) was removed in the initial filing.
3. Revised PPL Electric Exhibit Fully Projected Future 1 Schedule D-15 reflective of an adjustment to include the net salvage amount in the depreciation adjustment. This amount was inadvertently excluded from the D-15 adjustment in the initial filing but was included in PPL Electric Exhibit JJS-3.
4. Revised PPL Electric Exhibit Fully Projected Future 1 Schedule C-4 reflects the correction to the average lag in days between payment of O&M expenses and receipt of revenue value on page 2 line 3 which was explained in the response to I&E-RE-I-2-D.
5. PPL Electric Exhibit Fully Projected Future 1 Schedules B-5, C-1, C-4, C-6, D-1, D-2, D-16, D-17, and D-18 reflective of the changes described in numbers 1, 2, 3, and 4.

See OCA I-1 Attachment 232 SUPPLEMENTAL for the revised Attachment IV-C reflective of the changes in numbers 1 through 55. Additionally, this revision also includes changes to the volumes used to calculate the rates for GS-1 and GS-3. The volumes used previously incorrectly included sales to the volunteer rate schedules for GS-1 and GS-3, as such they were slightly overstated and resulted in rates that were slightly below what they should have been.

See OCA I-1 Attachment 233 SUPPLEMENTAL for the revised Attachment IV-D reflective of the changes in numbers 1 through 55.

See OCA I-1 Attachment 234 SUPPLEMENTAL for a revised PPL Electric Exhibit SWW-1 reflective of the changes in numbers 1 through 55.

See OCA I-1 Attachment 235 SUPPLEMENTAL for a revised version of PPL Electric Exhibit BR-1 reflective of the changes in numbers 1 through 55.

WITNESS: Various

See OCA I-1 Attachment 236 SUPPLEMENTAL for a revised
OCA I-1 Attachment 227 Wishart Rate Design Workpaper that
reflects the changes in numbers 1 through 5.

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Page 1 of 1
D.A. Urban**PPL ELECTRIC UTILITIES CORPORATION****Electric Service**
REVISED Statement of Net Utility Operating Income
Year Ended June 30, 2027
(Thousands of Dollars)

<u>Acct. No.</u>	<u>Title of Account</u>	<u>Amount</u>
400	Operating Revenue (B-3)	<u>\$ 3,463,885</u>
	Operating Expenses:	
401,402	Operation and Maintenance expenses (B-4)	
	Power production	846,332
	Transmission	335,381
	Regional market	-
	Distribution	207,592
	Customer accounts	86,338
	Customer service and informational expenses	132,910
	Sales	-
	Administrative and general	168,942
	Total Operation and Maintenance Expenses	<u>1,777,496</u>
403	Depreciation expense	441,245
404,405	Amortization of electric plant	27,030
407.3	Regulatory debits	11,007
407.4	Regulatory credits	0
	Taxes (B-5)	
408.1	Taxes other than income taxes	162,324
409.1	Income taxes	24,137
	Deferred income taxes	
410.1	Provision	163,315
411.1	Provision - Credit	(17,150)
411.4	Investment tax credit adjustments	(31)
	Total Taxes	<u>332,595</u>
411.6	Gains from disposition of utility plant	-
411.7	Losses from disposition of utility plant	-
	Total Operating Expenses	<u>2,589,373</u>
	Net Utility Operating Income	<u><u>\$ 874,513</u></u>

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Page 1 of 3
D.A. Urban

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REVISED Statement of Operation and Maintenance Expenses
Year Ended June 30, 2027
(Thousands of Dollars)

<u>Acct. No.</u>	<u>Title of Account</u>	<u>Amount</u>
	<u>Power Production Expenses</u>	
	Other Power Supply Expenses	
555	Purchased power	
	Market-based from EWGs	\$ 844,328
	Non-utility generation	
	PJM ancillary services	1,676
	Other	
556	System control and load dispatching	
	PJM ancillary services	6
	Other	0
557	Other expenses	323
	Total Other Power Supply Expenses	<u>846,332</u>
	Total Power Production Expenses	<u>846,332</u>
	<u>Transmission Expenses</u>	
	Operation	
560	Operation supervision and engineering	5,631
561	Load dispatching	2,641
562	Station expenses	644
563	Overhead line expenses	1,192
564	Underground line expenses	-
565	Transmission of electricity by others	300,212
566	Miscellaneous transmission expenses	5,822
567	Rents	1,324
	Total Transmission Operation Expenses	<u>317,467</u>
	Maintenance	
568	Maintenance supervision and engineering	11
569	Maintenance of structures	16
569.1	Maintenance of Computer Hardware	23
569.2	Maintenance of Computer Software	2,133
569.3	Maintenance of Communication Equipment	77
570	Maintenance of station equipment	4,455
571	Maintenance of overhead lines	10,321
572	Maintenance of underground lines	151
573	Maintenance of miscellaneous transmission plant	726
574	Maintenance of Transmission Plant	-
	Total Transmission Maintenance Expenses	<u>17,914</u>
	Total Transmission Expenses	<u>335,381</u>

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Page 2 of 3
D.A. Urban

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REVISED Statement of Operation and Maintenance Expenses
Year Ended June 30, 2027
(Thousands of Dollars)

<u>Acct. No.</u>	<u>Title of Account</u>	<u>Amount</u>
	<u>Regional Market Expenses</u>	
	Operation	
575.7	Market Facilitation, Monitoring and Compliance Services	\$ -
	Total Regional Market Expenses	-
	<u>Energy Storage Expenses</u>	
	Operation	
577.1	Operation Supervision and Engineering	\$ -
	Total Energy Storage Operation Expenses	-
	Maintenance	
578.2	Maintenance of Energy Storage Equipment and Structures	\$ -
	Total Energy Storage Maintenance Expenses	-
	Total Energy Storage Expenses	-
	<u>Distribution Expenses</u>	
	Operation	
580	Operation supervision and engineering	10,367
581	Load dispatching	2,295
582	Station expenses	86
583	Overhead line expenses	29,067
584	Underground line expenses	6,594
585	Street lighting and signal system expenses	-
586	Meter expenses	2,391
587	Customer installations expenses	3,026
588	Miscellaneous distribution expenses	18,181
589	Rents	7,534
	Total Distribution Operation Expenses	79,542
	Maintenance	
590	Maintenance supervision and engineering	-
591	Maintenance of structures	137
592	Maintenance of station equipment	12,185
593	Maintenance of overhead lines	110,715
594	Maintenance of underground lines	340
595	Maintenance of line transformers	182
596	Maintenance of street lighting and signal systems	2,424
597	Maintenance of meters	-
598	Maintenance of miscellaneous distribution plant	2,067
	Total Distribution Maintenance Expenses	128,050
	Total Distribution Expenses	207,592

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Page 3 of 3
D.A. Urban

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REVISED Statement of Operation and Maintenance Expenses
Year Ended June 30, 2027
(Thousands of Dollars)

<u>Acct. No.</u>	<u>Title of Account</u>	<u>Amount</u>
	<u>Customer Accounts Expenses</u>	
	Operation	
901	Supervision	4,218
902	Meter reading expenses	1,206
903	Customer records and collection expenses	39,367
904	Uncollectible accounts	37,959
905	Miscellaneous customer accounts expenses	3,589
	Total Customer Accounts Expenses	<u>86,338</u>
	<u>Customer Service and Informational Expenses</u>	
	Operation	
908	Customer assistance expenses	
	On-track uncollectible accounts	\$ 40,718
	Other	92,192
909	Informational and instructional expense	-
910	Miscellaneous customer service and informational expenses	-
	Total Customer Service and Informational Expenses	<u>132,910</u>
	<u>Sales Expenses</u>	
	Operation	
911	Supervision	-
912	Demonstrating and selling expenses	-
913	Advertising expenses	-
916	Miscellaneous sales expenses	-
	Total Sales Expenses	<u>-</u>
	<u>Administrative and General Expenses</u>	
	Operation	
920	Administrative and general salaries	55,208
921	Office supplies and expenses	22,312
922	Administrative Expenses Transferred-Credit	(6,624)
923	Outside services employed	41,326
924	Property insurance	3,955
925	Injuries and damages	8,548
926	Employee pensions and benefits	3,005
928	Regulatory commission expenses	6,818
930	Miscellaneous general expenses	(11,706)
931	Service Company Rents	1,165
		<u>124,008</u>
	Maintenance	
935	Maintenance of general plant	<u>44,934</u>
	Total Administrative and General Expenses	<u>168,942</u>
	Total Operation and Maintenance Expenses	<u>\$ 1,777,496</u>

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PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REVISED Statement of Detail - Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

<u>Line</u> <u>No.</u>	<u>Description</u>	<u>Amount</u>
	Taxes Other Than Income	
	State and Local	
1	Gross Receipts	\$ 146,950
2	Local property and Other	4,278
3	Public Utility Realty	3,175
4	State Unemployment Compensation	149
5	Sales and Use	0
6	Total State and Local	<u>154,552</u>
	Federal	
7	Unemployment Tax Act	34
8	Social Security and Hospital Insurance	7,738
9	Total Federal	<u>7,772</u>
10	Total Taxes Other Than Income	<u>162,324</u>
	Income Taxes	
11	State	282
12	Federal	23,855
13	Total Income Taxes	<u>24,137</u>
	Investment Tax Credit	
14	Deferred	0
15	Amortization of Deferral	(31)
16	Net Investment Tax Credit	<u>(31)</u>

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PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REVISED Statement of Detail - Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Federal</u>	<u>State</u>	<u>Amount</u>
	Deferred Income Taxes			
	Provision for Deferred Taxes			
	Net Book/Net Tax Plant Timing Differences:			
17	ACRS & MACRS - Distribution Property	34,502	0	34,502
18	Contributions in Aid of Construction (CIAC) - Transmission Property	418	135	553
19	Contributions in Aid of Construction (CIAC) - General Property	37	19	56
20	Net Book/Net Tax Plant - Transmission Property	64,357	30,687	95,044
21	Basis Adjustment - Distribution Property	19,245	6,975	26,220
22	Basis Adjustment - General Property	1,140	574	1,714
23	Federal NOL Carryforward - Distribution Property	0	0	0
24	State NOL Carryforward - Distribution Property	0	0	0
25	Deficient Federal NOL Deferred Taxes - Distribution Property	476	0	476
26	Deficient Federal NOL Deferred Taxes - Transmission Property	214	0	214
27	Bad Debts	61	23	84
28	Pension Benefits	2,736	1,022	3,758
29	Post-Employment Benefits	63	25	88
30	Post-Retirement VEBA	270	100	370
31	Prepays	172	64	236
32	Total Provision	123,691	39,624	163,315
	Provision for Deferred Taxes - Credit			
	Net Book/Net Tax Plant Timing Differences:			
33	ACRS & MACRS - General Property	(5,078)	(237)	(5,315)
34	Contributions in Aid of Construction (CIAC) - Distribution Property	(5,469)	(1,966)	(7,435)
35	Deferred Compensation - Officers	(76)	(29)	(105)
36	Environmental Cleanup	(32)	(12)	(44)
37	Loss - Reacquired Debt	(87)	(33)	(120)
38	Post-Retirement Benefits	(465)	(173)	(638)
39	Rate Case Expenses	(9)	(3)	(12)
40	Supplemental Executive Retirement Pension (SERP)	(56)	(21)	(77)
41	Service Company Temporary Costs	(278)	(104)	(382)
42	Vacation Pay	(56)	(21)	(77)
43	Storm Deferral	(2,147)	(798)	(2,945)
44	Total Credits	\$ (13,753)	\$ (3,397)	(17,150)
45	Total Deferred Income Taxes			146,165
46	Total All Taxes			\$ 332,595

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Various

PPL ELECTRIC UTILITIES CORPORATION

REVISED Rate Base and Rate of Return
12 Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Title of Account	Total T&D Operations	PPUC Jurisdictional (Exhibit BR-1)
	Electric Plant		
1	Electric plant in service (C-2)	\$ 20,346,907	\$ 10,176,227
1a	Electric plant in service (C-2) (IT Pro-forma)	25,880	25,880
2	Reserve for depreciation (C-2)	4,741,901	3,254,277
2a	Reserve for depreciation (C-2) (IT Pro-forma)	1,826	1,826
3	Net electric plant in service	<u>15,629,060</u>	<u>6,946,004</u>
	Additions		
4	Plant held for future use (C-3)	<u>0</u>	<u>0</u>
5	Total electric plant	<u>15,629,060</u>	<u>6,946,004</u>
	Working Capital		
6	Cash working capital (C-4)	781	16,529
7	Materials and operating supplies (C-5)	<u>109,289</u>	<u>72,146</u>
8	Total working capital	<u>110,070</u>	<u>88,675</u>
	Deductions		
9	Accumulated deferred taxes on income (C-6)	2,615,660	1,201,084
9a	Accumulated deferred taxes on income (C-6) (IT Pro-forma)	6,088	6,088
10	Customer advances for construction (B-1)	-	0
11	Customer deposits (B-1)	<u>6,554</u>	<u>6,554</u>
12	Total deductions	<u>2,628,302</u>	<u>1,213,726</u>
13	Rate Base (net)	<u>\$ 13,110,828</u>	<u>\$ 5,820,953</u>
	Pro forma return at present rates		
14	Amount (D-1, col. 6)		235,396
15	Percent		4.04%
	Pro forma return at proposed rates		
16	Amount (D-1, col. 8)		498,274
17	Percent		8.56%

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PPL ELECTRIC UTILITIES CORPORATION

REVISED Cash Working Capital
As of June 30, 2027
(Thousands of Dollars)

Line No.	<u>Description</u>	<u>Amount</u>
1	Operation and maintenance expense (C-4, page 2)	\$ 6,786
2	Average prepayments (C-4, page 3)	13,421
3	Accrued taxes (C-4, page 4)	14,377
4	Interest payments (C-4, page 5)	<u>(33,803)</u>
5	Total cash working capital requirement	<u>\$ 781</u>

PPL Electric Utilities Corporation**REVISED Working Capital Required for Operation and Maintenance Expenses****As of June 30, 2027**
(Thousands of Dollars)

The Company bills its customers every month. On this basis, there is a considerable span of days between the time electricity is furnished to a customer and the time the customer pays for such electricity.

In many instances, the Company must pay its bills for payroll and other O&M expenses prior to the time it is able to collect the amount due for the service which requires the incurrence of such expenses. Thus, the Company has examined its records to determine, as to the major categories of expense, the average span of days which exists between the time an expense is incurred and the time it must be paid. Schedule C-4, page 2, of Exhibit Historic 1 sets forth the individual components which result in the days lag between payment of expenses and receipt of the related revenues used in the determination of the working capital required for the pro forma O&M expense for the test year ending June 30, 2025.

<u>Line No.</u>	<u>Description</u>	<u>Amount</u>
1	Net pro forma O&M expense (a)	485,647
2	O&M expense per day (line 1 divided by 365 days)	1,331
3	Average lag in days between payment of O&M expenses and receipt of revenue (b)	5.1
4	Working capital requirement (line 2 x line 3)	<u>\$ 6,786</u>
(a)	Total pro forma operation and maintenance expense (D-1 col. 5 lines 2-4)	\$ 1,053,797
	Less: Non-cash items	
	Uncollectible accounts expense	14,735
	Deferred Storm Outage Costs (D-9)	3,779
	Deferred IIJA Costs (D-10)	211
	Depreciation (D-1 col. 5 line 3)	<u>549,425</u>
	Net pro forma O&M expense	<u>\$ 485,647</u>

(b) See Exhibit Historic 1, Schedule C-4, page 2.

PPL ELECTRIC UTILITIES CORPORATION

Average Prepayments
As of June 30, 2027
(Thousands of Dollars)

Line No.	Month	<u>Insurance</u>	<u>PUC Annual Assessment</u>	<u>Other</u>	<u>Total</u>
1	July 2026	\$3,648	\$3,850	\$6,680	\$14,178
2	August 2026	3,014	3,500	6,527	\$13,041
3	September 2026	2,815	5,726	6,373	\$14,914
4	October 2026	2,188	5,089	6,345	\$13,623
5	November 2026	1,561	4,453	6,265	\$12,279
6	December 2026	960	3,817	6,007	\$10,784
7	January 2027	5,283	3,181	6,252	\$14,717
8	February 2027	4,614	2,354	6,546	\$13,514
9	March 2027	3,944	1,765	7,956	\$13,665
10	April 2027	3,489	1,177	9,065	\$13,731
11	May 2027	4,988	588	8,807	\$14,384
12	June 2027	4,410	(0)	8,411	\$12,821
13	July 2027	4,410	(0)	8,411	\$12,821
14	Total Prepayments	\$45,323	\$35,501	\$93,645	\$174,470
15	Monthly Average	\$3,486	\$2,731	\$7,203	\$13,421

PPL ELECTRIC UTILITIES CORPORATION

REVISED Accrued Taxes
Year Ended June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Amount</u>	<u>12-Month Accrued Factor (a)</u>	<u>Accrued Taxes</u>
1	Federal income tax (D-1, line 6, col. 5)	15,880	-11.62%	(\$1,846)
2	PA income tax (D-1, line 7, col. 5)	(3,156)	-9.54%	301
3	PA gross receipts tax (D-16, page 3)	56,151	27.96%	15,700
4	PA capital stock tax (D-16, page 2)	0	0.00%	0
5	PA public utility reality tax (D-16, page 4)	3,110	7.13%	222
6	Total accrued taxes			<u>\$14,377</u>

- (a) The 12-month average factor represents, in the case of Federal and State income tax and capital stock tax, the portion of the tax liability which is available to the Company for the payment of other costs. This situation exists because revenue is available from customers prior to payment dates of the tax. The factors for the other Pennsylvania taxes represent the portions of those tax liabilities which must be provided by the Company due to payment of the taxes before the revenue is available from customers. Exhibit Historic 1, Schedule C-4, pages 6 through 11 reflect the computation of such factors.

PPL ELECTRIC UTILITIES CORPORATION

REVISED Interest Payments
As of June 30, 2027
(Thousands of Dollars)

Line No.	<u>Description</u>		<u>Amount</u>
1	Rate Base at June 30, 2027 (C-1)		\$ 13,110,828
2	Long-term debt ratio (B-8)		43.95%
3	Embedded cost of long-term debt (B-8)		5.08%
4	Pro forma interest (line 1 x line 2 x line 3)		<u>292,371</u>
5	Daily amount (line 4 ÷ 365)		<u>\$ 801</u>
6	Days to mid-point of interest payments	90.0	
7	Less: Revenue lag days (Historic C-4, page 2)	<u>47.8</u>	
8	Interest payments lag days (line 6 - line 7)		<u>42.2</u>
9	Total interest payments (line 5 x line 8)		<u>\$ 33,803</u>

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PPL ELECTRIC UTILITIES CORPORATION

REVISED Accumulated Deferred Taxes on Income
Year Ended June 30, 2027
(Thousands of Dollars)

Line					
<u>No.</u>	<u>Description</u>		<u>Amount Including IT Proforma</u>	<u>IT Proforma</u>	<u>Amount Excluding IT Proforma</u>
Distribution					
1	Accelerated Cost Recovery System (ACRS/MACRS) (a)	\$ 778,767	\$ -	\$ 778,767	
2	Contributions In Aid Of Construction (CIAC)	(155,133)	0	(155,133)	
3	Other Plant Basis Adjustments (a)	<u>500,288</u>	6,088	494,200	
4	Balance at June 30, 2027		<u>\$ 1,123,922</u>	<u>\$ 6,088</u>	<u>\$ 1,117,834</u>
General					
5	Accelerated Cost Recovery System (ACRS/MACRS)	98,692	0	98,692	
6	Contributions In Aid Of Construction (CIAC)	(213)	0	(213)	
7	Other Plant Basis Adjustments	<u>(12,791)</u>	0	(12,791)	
8	Balance at June 30, 2027		<u>85,688</u>	<u>0</u>	<u>85,688</u>
Transmission					
9	Contributions In Aid Of Construction (CIAC)	(19,034)	0	(19,034)	
10	Net Book/Net Tax Plant (Excluding CIAC) (a)	<u>1,431,172</u>	0	1,431,172	
11	Balance at June 30, 2027		<u>1,412,138</u>	<u>0</u>	<u>1,412,138</u>
Total (B-1)					
12	Accelerated Cost Recovery System (ACRS/MACRS)	877,459	0	877,459	
13	Contributions In Aid Of Construction (CIAC)	(174,380)	0	(174,380)	
14	Net Book/Net Tax Plant (Excluding CIAC) - Transmission	1,431,172	0	1,431,172	
15	Other Plant Basis Adjustments	<u>487,497</u>	6,088	481,409	
16	Total accumulated deferred taxes on income		<u>\$ 2,621,748</u>	<u>\$ 6,088</u>	<u>\$ 2,615,660</u>

(a) Accelerated cost recovery system and Other Plant Basis Adjustments are netted with applicable deficient deferred taxes related to net operating losses on lines 1, 3 and 10.

PPL ELECTRIC UTILITIES CORPORATION

REVISED Accumulated Deferred Taxes on Income
Year Ended June 30, 2027
Reg 1.167(l)-(h)(6)ii
(Thousands of Dollars)

<u>Line No.</u>			<u>Total Amount Including IT Proforma</u>		<u>IT Proforma</u>		<u>Total Amount Excluding IT Proforma</u>
1	Accumulated Deferred Taxes at June 30, 2026		\$ 2,559,432		\$ -		\$ 2,559,432
2	Projected Accumulated Deferred Taxes at June 30, 2027		2,695,968		13,338		2,682,630
3	Increase in Accumulated Deferred Taxes for July 1, 2026 - June 30, 2027		<u>\$ 136,536</u>		<u>\$ 13,338</u>		<u>\$ 123,198</u>
		<u>Proration</u>	<u>Monthly Increase</u>		<u>Monthly Increase</u>	<u>Monthly Increase</u>	
4	Balance June 30, 2026		\$ 2,559,432		\$ -		\$ 2,559,432
5	July 1-31, 2026	334 / 365	\$ 11,378 10,412	\$ 1,112	1,018	\$ 10,266	9,394
6	August 1-31, 2026	303 / 365	11,378 9,445	1,111	922	10,267	8,523
7	September 1-30, 2026	273 / 365	11,379 8,511	1,112	832	10,267	7,679
8	October 1-31, 2026	242 / 365	11,378 7,544	1,111	737	10,267	6,807
9	November 1-30, 2026	212 / 365	11,378 6,609	1,112	646	10,266	5,963
10	December 1-31, 2026	181 / 365	11,378 5,642	1,111	551	10,267	5,091
11	January 1-31, 2027	150 / 365	11,378 4,676	1,112	457	10,266	4,219
12	February 1-28, 2027	122 / 365	11,378 3,803	1,111	371	10,267	3,432
13	March 1-31, 2027	91 / 365	11,379 2,837	1,112	277	10,267	2,560
14	April 1-30, 2027	61 / 365	11,378 1,902	1,111	186	10,267	1,716
15	May 1-31, 2027	30 / 365	11,378 935	1,112	91	10,266	844
16	June 1-30, 2027	0 / 365	11,378 0	1,111	0	10,267	0
17	Balance June 30, 2026 plus pro rata portion of monthly increases		<u>\$ 2,621,748</u>		<u>\$ 6,088</u>		<u>\$ 2,615,660</u>
18	Projected Accumulated Deferred Taxes at June 30, 2027 (Line 2)		2,695,968		13,338		2,682,630
19	Proration Adjustment (Line 17 - Line 18)		<u>\$ (74,220)</u>		<u>\$ (7,250)</u>		<u>\$ (66,970)</u>

PPL ELECTRIC UTILITIES CORPORATION

REVISED Operating Income
Pro Forma at Present and Proposed Rates
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Total Amount Per Books	Less: Automatic Cost Recovery Clauses/Riders ¹⁾	T & D Operations Per Books	Pro Forma Adjustments (D-2)	T & D Pro Forma at Present Rates	Pro Forma at Present Rates (Exhibit BR-1)	PPUC Jurisdictional Rate Increase (D-17, Pg. 4)	Pro Forma at Proposed Rates
1	Operating Revenues	\$ 3,463,885	\$ (1,420,551)	\$ 2,043,334	\$ 4,723	\$ 2,048,057	\$ 1,070,620	\$ 389,320	\$ 1,459,940
	Operating Expenses								
2	Operation and Maintenance	1,777,496	(1,276,262)	501,234	(852)	500,382	427,139	7,621	434,760
3	Depreciation	468,275	0	468,275	81,150	549,425	324,180	0	324,180
4	Regulatory Debits/Credits	11,007	(11,007)	0	3,990	3,990	3,990	0	3,990
	Provision for Taxes								
5	Taxes Other Than Income	162,324	(90,524)	71,800	(376)	71,424	67,337	22,970	90,307
	Income Taxes								
6	Federal	23,855	(8,329)	15,526	354	15,880	(22,989)	69,879	46,890
7	State	282	(3,096)	(2,814)	(342)	(3,156)	(10,888)	25,972	15,084
8	Deferred Income Taxes	146,165	0	146,165	(9,629)	136,536	46,470	0	46,470
9	Investment Tax Credit	(31)	0	(31)	0	(31)	(15)	0	(15)
10	Total Taxes	332,595	(101,949)	230,646	(9,993)	220,653	79,916	118,821	198,736
11	(Gain)/Loss from Disposition of Utility Plant	0	0	0	0	0	0	0	0
12	Total Operating Expenses	2,589,373	(1,389,217)	1,200,155	74,295	1,274,450	835,224	126,442	961,666
13	Operating Income	\$ 874,513	\$ (31,334)	\$ 843,179	\$ (69,572)	\$ 773,607	\$ 235,396	\$ 262,878	\$ 498,274

¹⁾ Automatic Recovery Clauses/Riders include CER, TCJA, SMR-2, DSIC, GSC-1, GSC-2, MFC, TSC, USR, ACR, and SDER for line 1, and GSC-1, GSC-2, MFC, TSC, USR, ACR, and SDER for all other lines.

NOTE: Totals may not tie due to rounding

PPL ELECTRIC UTILITIES CORPORATION

REVISED Adjustments to Income
12 Months Ended June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Reference</u>	<u>Description</u>	<u>Amount</u>
		<u>Operating Revenues</u>	
1	D-3 and D-4	Operating Revenue	\$ 4,723
		<u>Operation and Maintenance Expenses</u>	
2	D-5	Employee wages and benefits (D-5 Line 5 + Line 6)	(518)
3	D-6	Rate case expense	733
4	D-7	Economic Development Proposal Adjustment	400
5	D-8	Competitive Enhancement Charge Adjustment	100
6	D-9	Deferred Storm Expenses Adjustment	3,779
7	D-10	IIJA Expense Deferral Adjustment	211
8	D-11	USR Salaries Adjustment	(1,400)
9	D-12	Interest Expense on Customer Deposits	300
10	D-13	Company Use Generation Supply Purchase	1,359
11	D-14	Capital Treatment of Certain IT Expenditures	(1,826)
12		Total operation and maintenance expense	3,138
		<u>Depreciation</u>	
13	D-14	Capital Treatment of Certain IT Expenditures	1,826
14	D-15	Annual depreciation expense	79,324
15		Total depreciation expense	81,150
		<u>Provision for Taxes</u>	
		Taxes other than income	
16		Capital stock	0
17	D-16	Gross receipts	(275)
18	D-16	Public utility realty	(65)
19	D-5	Payroll taxes	(36)
		Income taxes	
20	D-17	Federal	354
21	D-17	State	(342)
22	D-18	Deferred income taxes	(9,629)
23			
23	D-19	Investment tax credit - amortization	0
24		Total Taxes	(9,993)
25		Gain and losses on property dispositions	0
26		Total Operating Expenses	74,295
27		Total Adjustments to Income	\$ (69,572)

PPL ELECTRIC UTILITIES CORPORATION

REVISED Adjustments to Operating Revenue
Period Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	(1) Total Per Books	(2) Less: Automatic Cost Recovery Clauses/Riders ^{a)}	(3) T&D Operations Per Books	(4) Pro Forma Adjustments	(5) T&D Pro forma at Present Rates
1	Distribution revenue	\$ 1,188,312	\$ (183,073)	\$ 1,005,239	\$ 4,933 ^{b)}	\$ 1,010,172
2	Transmission Service Charge (TSC) revenue	325,313	(325,313)	0	0	0
3	Generation Service Charge (GSC) Revenue	915,486	(915,486)	0	0	0
4	State Tax Surcharge (STAS) revenue	(4,707)	4,707	-	0	-
5	Sales for Resale	319	0	319	0	319
6	Total Rate Revenue	<u>\$ 2,424,723</u>	<u>\$ (1,419,164)</u>	<u>\$ 1,005,558</u>	<u>\$ 4,933</u>	<u>\$ 1,010,491</u>
<u>Other Electric Revenue</u>						
7	Late Payment	15,306	0	15,306	0	15,306
8	Misc. Revenue	970	0	970	0	970
9	Rent	43,746	0	43,746	0	43,746
10	Other	978,510	(965)	977,545	0	977,545
11	Total Other	<u>\$ 1,038,531</u>	<u>\$ (965)</u>	<u>\$ 1,037,566</u>	<u>\$ -</u>	<u>\$ 1,037,566</u>
12	Operating Revenue (excl. unbilled)	3,463,254	(1,420,130)	2,043,124	4,933	2,048,057
13	Unbilled Revenue (D-4)	631	(422)	210	(210)	0
14	Total Operating Revenue	<u><u>\$ 3,463,885</u></u>	<u><u>\$ (1,420,551)</u></u>	<u><u>\$ 2,043,334</u></u>	<u><u>\$ 4,723</u></u>	<u><u>\$ 2,048,057</u></u>

^{a)} Automatic Recovery Clauses/Riders include GSC-1, GSC-2, MFC, TSC, TCJA, STAS, USR, ACR, CER, SDER, SMR and DSIC.

^{b)} This adjustments is for annualization.

PPL ELECTRIC UTILITIES CORPORATION

REVISED Adjustment to Annual Depreciation Expense
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.	Depreciation - Electric Plant In Service	Total
		<u>Amount</u>
1	Intangible Plant	\$ -
2	Transmission Plant	224,744
3	Distribution Plant	263,091
4	General Plant	59,764
6	Total (a)	547,599
7	Less: Depreciation expense per books	468,275
8	Net increase in depreciation expense	\$ 79,324

(a) Includes net salvage of \$59,424

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PPL ELECTRIC UTILITIES CORPORATION

REVISED Adjustment to Taxes Other Than Income
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Amount</u>
	<u>PA Gross Receipts Tax</u>	
	Adjustment to provide for gross receipts tax on pro forma revenue at present rates	
1	Gross receipts tax recoverable through base rates (D-16, page 2)	\$ 56,151
2	Less: Gross receipts tax on T&D operations per budget (Sch B-5, page 1, line 1 plus Sch D-17, page 1, column 2, line 5)	<u>56,426</u>
3	Net decrease in expense	<u><u>\$ (275)</u></u>
	<u>PA Public Utility Realty</u>	
	Adjustment to reflect current taxable value	
4	Public utility realty tax recoverable through base rates (D-16 SUPPLEMENTAL, page 2)	\$ 3,110
5	Less: Public utility realty tax on T&D operations per budget (B-5, page 1, line 3)	<u>3,175</u>
6	Net decrease in expense	<u><u>\$ (65)</u></u>

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PPL ELECTRIC UTILITIES CORPORATION

Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Gross Receipts Tax (GRT) at Present Rates

<u>Line No.</u>	<u>Description</u>	<u>Pro Forma Revenue</u>	<u>GRT Rate (Mills)</u>	<u>Amount</u>
	Tariff Revenue			
	Total Tariff Revenue (D-3 page 1, line 6)			
1		\$ 1,010,491	59	\$ 59,619
	Other Electric Revenue			
2	Late payment (D-3, page 1, line 7)	15,306	59	903
3	Other electric revenue (D-3, page 1, lines 8-10)	1,022,260	-	0
4	Total Other	<u>1,037,566</u>		
5	Total (D-3, page 1, line 14)	<u>2,048,057</u>		<u>60,522</u>
6	Plus: Bad debt adjustment	(74,088)	59	(4,371)
7	Total gross receipts tax on pro forma revenue at present rates			<u>\$ 56,151</u>

Public Utility Realty Tax (PURTA) at Present Rates

	<u>Description</u>	<u>Amount</u>
8	State Taxable Value (per Notice of Determination dated July 30, 2025)	\$ 133,376
9	Rate @ 23.3189 mills (per Notice of Determination dated July 30, 2025)	<u>0.0233189</u>
10	Tax Amount	<u>\$ 3,110</u>

PPL ELECTRIC UTILITIES CORPORATION
REVISED Computation of Income Taxes - Electric
 Twelve Months Ended June 30, 2027
 (Thousands of Dollars)

Line No.	Description	Total Amount Per Budget	Less: Automatic Recovery Clauses/Riders	T&D Operations Per Budget	Pro forma Adjustments	T&D Pro forma at Present Rates
1	Operating Revenues	\$ 3,463,885	\$ (1,420,551)	\$ 2,043,334	\$ 4,723	\$ 2,048,057
	Operating Expenses					
2	Operation and maintenance	1,777,496	(1,276,262)	501,234	(852)	500,382
3	Depreciation and amortization	468,275	0	468,275	81,150	549,425
4	Regulatory Debits and Credits	11,007	(11,007)	0	3,990	3,990
5	Taxes Other than Income	162,324	(90,524)	71,800	(376)	71,424
6	Income Taxes	23,855	(8,329)	15,526	354	15,880
7	Income Taxes - State	282	(3,096)	(2,814)	(342)	(3,156)
8	Deferred Income Taxes	146,165	0	146,165	(9,629)	136,536
9	Investment Tax Credit - Amortization	(31)	0	(31)	0	(31)
10	Gains and Losses on Property Dispositions		0	0	0	0
11	Total Operating Expense	2,589,373	(1,389,217)	1,200,155	74,295	1,274,450
		0				
12	Operating Income	874,513	(31,334)	843,179	(69,572)	773,607
13	Less: Interest Expense	306,018	0	306,018	(13,647)	292,371
14	Net Operating Income	568,495	(31,334)	537,161	(55,926)	481,236
15	Income Tax Adjustments					
16	Federal Income Tax	23,855	(8,329)	15,526	354	15,880
17	State Income Tax	282	(3,096)	(2,814)	(342)	(3,156)
18	Deferred Income Taxes	146,165	0	146,165	(9,629)	136,536
19	Investment tax credit amortization	(31)	0	(31)	0	(31)
	Permanent Items:					
20	Bad Debt Expense Net of Write-offs	500	0	500	0	500
21	ESOP dividend paid in cash	(2,100)	0	(2,100)	0	(2,100)
22	Nondeductible Officers Compensation	5,550	0	5,550	0	5,550
23	Nondeductible Subsidized Expenses	1,500	0	1,500	0	1,500
	Plant Temporary Items:					
24	Book Depreciation	468,275	0	468,275	79,324	547,599
25	Book Depreciation Capitalized	5,160	0	5,160	(5,160)	0
26	Contributions in aid of construction	40,198	0	40,198	0	40,198
27	Plant Basis Adjustments - Tax Repairs and Other	(196,193)	0	(196,193)	(49,920)	(246,113)
28	Plant Basis Adjustments - Capitalized R&D	38,106	0	38,106	0	38,106
29	Removal costs	(105,534)	0	(105,534)	24,722	(80,812)
30	Tax Depreciation	(878,210)	0	(878,210)	24,161	(854,049)
31	Tax Gains/(Losses) on Plant Dispositions	5,026	0	5,026	0	5,026
	Non-Plant Temporary Items:					
32	Bad Debt Expense Net of Write-offs	(314)	0	(314)	0	(314)
33	Deferred Compensation - Officers	390	0	390	0	390
34	Environmental Clean-up	160	0	160	0	160
35	Pension and supplemental retirements	(13,763)	0	(13,763)	0	(13,763)
36	Post-employment benefits	(330)	0	(330)	0	(330)
37	Post-retirement benefits	2,388	0	2,388	0	2,388
38	Post-retirement - VEBA	(1,384)	0	(1,384)	0	(1,384)
39	Prepays	(882)	0	(882)	0	(882)
40	Reacquired debt costs	450	0	450	0	450
41	Regulatory Asset - Competitive Enhancement Rider (CER)	0	0	0	100	100
42	Regulatory Asset - IJJA Expense Deferral Adjustment	0	0	0	211	211
43	Regulatory Asset - Rate Cases Expenses	48	0	48	693	741
44	Regulatory Asset - Storm Deferral	11,022	0	11,022	(7,243)	3,779
45	Service Company Costs	1,426	0	1,426	0	1,426
46	Vacation Pay	290	0	290	0	290
47	Income Tax Adjustments	(447,950)	(11,425)	(459,375)	57,271	(402,104)
48	Taxable Net Income Before Special Deductions	\$ 120,545	\$ (42,759)	\$ 77,786	\$ 1,345	\$ 79,132

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A.W. Elmore

PPL ELECTRIC UTILITIES CORPORATION
REVISED Computation of Income Taxes - Electric
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	Total Amount Per Budget	Less: Automatic Recovery Clauses/Riders	T&D Operations Per Budget	Pro forma Adjustments	T&D Pro forma at Present Rates
<u>PA Corporate Net Income Tax Calculation</u>						
1	Taxable Net Income Before Special Deductions	\$ 120,545	\$ (42,759)	\$ 77,786	\$ 1,345	\$ 79,132
	PA Special Deductions					
2	Dividends Paid Credit		0	0	0	0
3	Bonus Depreciation Adjustment	(118,599)	0	(118,599)	(6,076)	(124,675)
4	State Adjustment	0	0	0	0	0
5	PA Taxable Income / (Loss) before NOL CF/(Utilization)	1,946	(42,759)	(40,813)	(4,731)	(45,543)
6	PA NOL Carryforward/(Utilization)	0	0	0	0	0
7	PA Taxable Income / (Loss) after NOL CF/(Utilization)	1,946	(42,759)	(40,813)	(4,731)	(45,543)
8	PA Tax @ 7.49% for Jul-Dec 2026 and 6.99% for Jan-Jun 2027	282	(3,096)	(2,814)	(342)	(3,156)
9	PA Tax Credits	0	0	0	0	0
10	Accrual for Potential Deficiency	0	0	0	0	0
11	State Income Tax Settlements	0	0	0	0	0
12	Prior Period Tax Return Adjustments	0	0	0	0	0
13	Total PA Income Tax	<u>\$ 282</u>	<u>\$ (3,096)</u>	<u>\$ (2,814)</u>	<u>\$ (342)</u>	<u>\$ (3,156)</u>
<u>Federal Income Tax Calculation</u>						
14	Taxable Net Income Before Special Deductions	\$ 120,545	\$ (42,759)	\$ 77,786	\$ 1,345	\$ 79,132
	Federal Special Deductions					
15	PA Income Tax Less Tax Credits	(282)	3,096	2,814	342	3,156
16	Dividends Paid Credit	0	0	0	0	0
17	State Income Tax Settlements	0	0	0	0	0
18	State Income Tax Adjustment for Prior Year	0	0	0	0	0
19	Federal Taxable Income	120,263	(39,663)	80,600	1,687	82,288
20	Federal NOL Carryforward/(Utilization)	0	0	0	0	0
21	Federal Taxable Income after NOL CF/(Utilization)	120,263	(39,663)	80,600	1,687	82,287
22	Federal Tax @ 21%	25,255	(8,329)	16,926	354	17,280
23	Federal Tax Credits	(1,400)	0	(1,400)	0	(1,400)
24	Accrual for Potential Deficiency	0	0	0	0	0
25	Prior Period Tax Return Adjustments	0	0	0	0	0
26	Total Federal Income Tax	<u>\$ 23,855</u>	<u>\$ (8,329)</u>	<u>\$ 15,526</u>	<u>\$ 354</u>	<u>\$ 15,880</u>

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A.W. Elmore

PPL ELECTRIC UTILITIES CORPORATION
REVISED Adjustment to Interest Deduction for Income Tax Purposes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

This adjustment provides for the annualized interest on claimed measures of value at June 30, 2027.

Line No.	Description	Amount
1	Measures of value at June 30, 2027 (C-1)	\$ 13,110,828
2	Long-term debt ratio (B-8)	43.95%
3	Embedded cost of long-term debt (B-8)	5.08%
4	Annualized interest (line 1 x line 2 x line 3)	<u>292,371</u>
5	Less: Interest expense on T&D operations (D-17, page 1, line 13, column 3)	<u>306,018</u>
6	Net decrease in interest deduction (line 4 - line 5)	<u><u>\$ (13,647)</u></u>

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A.W. Elmore

PPL ELECTRIC UTILITIES CORPORATION
REVISED Operating Revenue and Applicable Tax
Related to Proposed Rate Increase
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	Amount
1	Additional operating revenue from proposed rate increase	\$ 389,320
	Less:	
2	Provision for uncollectible accounts expense (line 1 x 1.67%)	6,502
3	Provision for PUC Assessment expense (line 1 x .28757%)	1,119
4	PA gross receipts tax (line 1 x 59 mills)	22,970
5	Taxable income for PA Corporate net income tax (line 1 less lines 2, 3 and 4)	<u>358,729</u>
6	PA corporate net income tax (line 5 x 7.24%) = (7.49% x 50% + 6.99% x 50%)	<u>25,972</u>
7	Taxable income for Federal income tax	332,757
8	Federal income tax (line 7 x 21%)	<u>69,879</u>
9	Operating income	<u><u>\$ 262,878</u></u>

PPL ELECTRIC UTILITIES CORPORATION

REVISED Adjustment to Deferred Income Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Provision	Debit	Credit	Net Deferred Tax Amount per Budget	Adjustments	T&D Operations per Budget	T&D Pro forma at Present Rates	Net increase / (decrease) in deferred income taxes
Distribution Property:								
1	Method and Life Book/Tax Plant Differences	\$ 34,502	\$ -	\$ 34,502	\$ 0	\$ 34,502	\$ (4,938)	\$ (39,440)
2	Contributions In Aid of Construction (CIAC)	0	(7,435)	(7,435)	0	(7,435)	(6,949)	486
3	Other Plant Basis Adjustments	26,220	0	26,220	0	26,220	37,579	11,359
4	Federal NOL Carryforward	0	0	0	0	0	0	0
5	State NOL Carryforward	0	0	0	0	0	0	0
6	Deficient Federal NOL Deferred Taxes	476	0	476	0	476	476	0
7	Non-Plant Deferred Taxes	4,489	(4,184)	305	0	305	0	(305)
8	Total Distribution Property	65,687	(11,619)	54,068	0	54,068	26,168	(27,900)
General Property:								
9	Method and Life Book/Tax Plant Differences	0	(5,315)	(5,315)	0	(5,315)	18,003	23,318
10	Contributions In Aid of Construction (CIAC)	56	0	56	0	56	61	5
11	Other Plant Basis Adjustments	1,714	0	1,714	0	1,714	2,318	604
12	Non-Plant Deferred Taxes	0	0	0	0	0	0	0
13	Total General Property	1,770	(5,315)	(3,545)	0	(3,545)	20,382	23,927
Transmission Property:								
14	Contributions In Aid of Construction (CIAC)	553	0	553	0	553	842	289
15	Net Book/Net Tax Plant (Excluding CIAC)	95,044	0	95,044	0	95,044	88,930	(6,114)
16	Federal NOL Carryforward	0	0	0	0	0	0	0
17	State NOL Carryforward	0	0	0	0	0	0	0
18	Federal Deficient NOL Deferred Taxes	214	0	214	0	214	214	0
19	Non-Plant Deferred Taxes	47	(216)	(169)	0	(169)	0	169
20	Total Transmission Property	95,858	(216)	95,642	0	95,642	89,986	(5,656)
Total								
21	Method and Life Book/Tax Plant Differences	34,502	(5,315)	29,187	0	29,187	13,065	(16,122)
22	Contributions In Aid of Construction (CIAC)	609	(7,435)	(6,826)	0	(6,826)	(6,046)	780
23	Other Plant Basis Adjustments	27,934	0	27,934	0	27,934	39,897	11,963
24	Net Book/Net Tax Plant (Excluding CIAC)-Transmission	95,044	0	95,044	0	95,044	88,930	(6,114)
25	Federal NOL Carryforward	0	0	0	0	0	0	0
26	State NOL Carryforward	0	0	0	0	0	0	0
27	Federal Deficient NOL Deferred Taxes	690	0	690	0	690	690	0
28	Non-Plant Deferred Taxes	4,536	(4,400)	136	0	136	0	(136)
29	Total	\$ 163,315	\$ (17,150)	\$ 146,165	\$ -	\$ 146,165	\$ 136,536	\$ (9,629)
D-17, Col 1 D-17, Col 2 D-17, Col 3 D-17, Col 5 D-17, Col 4								
30	Deferred Taxes per Schedule D-17 SUPPLEMENTAL			146,165	0	146,165	136,536	(9,629)

PPL ELECTRIC UTILITIES CORPORATION

REVISED Adjustment to Provision For Deferred Income Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

This adjustment provides for the annual provision for deferred income taxes due to the (1) Accelerated Cost Recovery System (ACRS) of the Economic Recovery Act of 1981, (2) Modified Accelerated Cost Recovery System (MACRS) of the Tax Reform Act of 1986 and (3) Plant Basis Adjustments

Line

		<u>Per T&D Proforma Sch D-17 SUPPLEMENTAL Col 5</u>
<u>No.</u>	<u>Description</u>	
	Distribution Property	
1	(Excess)/Deficient Tax over Book depreciation on ACRS and MACRS property	\$ (8,647)
2	Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	(187,658)
3	Reversal of Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	<u>60,312</u>
4	Plant activity for the calculation of deferred income taxes	<u>(135,993)</u>
	General Property	
5	Excess Tax over Book depreciation on ACRS and MACRS property	(88,415)
6	Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	0
7	Reversal of Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	<u>(6,579)</u>
8	Plant activity for the calculation of deferred income taxes	<u>(94,994)</u>
	Transmission Property	
9	Excess Tax over Book depreciation on ACRS and MACRS property	(289,328)
10	Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	(60,963)
11	Reversal of Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	<u>31,233</u>
12	Plant activity for the calculation of deferred income taxes	<u>(319,058)</u>
13	Total plant activity for the calculation of deferred income taxes	<u>\$ (550,045)</u>
14	Tax Rate	
	Provisions for Distribution and General Property - 21%	
	Reversals for Distribution and General Property - Average	
	Rate Assumption Method (ARAM)	
	Provisions for Transmission Property - 26.9171% (2026) & 26.5221% (2027)	
	Reversals for Transmission Property - ARAM	
	Provisions for Plant Basis Adjustments - 26.9171% (2026) & 26.5221% (2027)	
	Reversals for Plant Basis Adjustments - ARAM	
15	Net annual deferred tax debit / (credit) (Sch D-18, Page 1, line 29, column f)	\$ 136,536
	Less: Net provision on T&D operations per budget	
16	Provision for deferred taxes - debit	
17	Provision for deferred taxes - credit	
18	Sub-Total (Sch D-18, Page 1, line 29, column c)	146,165
	Less: Net deferred tax debit / (credit) on Automatic Recovery Riders	
19	Sch D-18, Page 1, line 29, column d	0
20	Net increase in deferred income tax provision (line 15 less lines 18 and 19)	<u>\$ (9,629)</u>

WITNESS: Various

PPL Electric Utilities Corporation
Response to the RE Set I Data Requests of the
Bureau of Investigation and Enforcement
Dated October 10, 2025
Docket No. R-2025-3057164

I&E-RE-I-2-D Reference PPL Volume V, Schedules D-1 through D-19.
Provide similar schedules with additional columns for the fiscal
years ended June 20, 2021 (FY 2021), June 30, 2022 (FY
2022), June 30, 2023 (FY 2023), and June 20, 2024 (FY 2024)
in Microsoft Excel format with all formulas intact.

PPL Electric See I&E-RE-I-2-D Attachment 1.
Response

In the process of preparing this response, the Company
identified an error in the Exhibit Historic 1, Schedule D-1 which
resulted in an increase in the amount of O&M expense in Row
2, Column 5. The resulting change in the average lag in days
between payment of O&M expenses and receipt of revenue
value in the cash working capital calculation, which was
reduced from 5.2 days to 5.1 days, has been used in the data
provided in this response.

The Company will prepare and provide revised Exhibit Historic
1, Exhibit Future 1, and Exhibit Fully Future 1 schedules that
correct this error in all impacted schedules as a supplement to
this response.

WITNESS: Dennis A. Urban Jr.

PPL Electric Utilities Corporation
Response to the Set XXV Data Requests of the
Office of Consumer Advocate (OCA)
Dated December 4, 2025
Docket No. R-2025-3057164

OCA XXV-9

Refer to the response to I&E-RE-I-12-D (B).

- a. Please confirm that the FTY and FPFTY amounts of \$900,000 refer to bank charges. If not, please clarify what the \$900,000 represents.
- b. Please explain how the \$900,000 Bank Charges for the FTY and FPFTY were determined and provide the supporting documentation.

PPL Electric
Response

- a. Yes, they are bank charges.
- b. Bank Charges were determined by analyzing the prior year's fees and adjusting for any increased volumes and fees, where applicable.

Bank	FTY	FPFTY
US Bank	\$ 22,265	\$ 22,000
Bank of America	7,042	7,000
Well Fargo	80,660	82,341
BNYM	688,055	704,500
CIBC	333	333
BNYM	51,742	52,957
Total	\$ 850,097	\$ 869,131

WITNESS: Sharon Leskowsky
Dennis A. Urban

PPL Electric Utilities Corporation
Response to the RE Set I Data Requests of the
Bureau of Investigation and Enforcement
Dated October 10, 2025
Docket No. R-2025-3057164

I&E-RE-I-12-D

Reference PPL Volume VII, Schedules D-1 through D-19. For each of the following, provide distribution-level details by year identifying (1) the account name/number, (2) the payee(s), (3) the expense amount incurred in FY 2021 through the HTY, forecasted for the FTY, and claimed for the FPFTY, and (4) the basis for why each expense is appropriate to include for distribution ratemaking purposes:

- A. Fines and penalties.
- B. Bank charges.
- C. Clearinghouse fees.
- D. Subscriptions.
- E. Company sponsorships.
- F. Lobbying expenses/Political campaign donations.
- G. Membership dues and subscriptions.
- H. Donations.
- I. Charitable or civic contributions.

PPL Electric
Response

- A. Fines and Penalties are recorded to "Other income and (deductions)," Account 426, and not to operating expenses. Therefore, contributions of this type are not reflected in customer rates.

However, in preparing the response to this discovery request, the Company identified a \$1,000 civil penalty recorded in May 2025 that was incorrectly charged to "Supervision – Customer Accounts", Account 901. The Company will make a correction to move this expense to "Other income and (deductions)," Account

WITNESS: Sharon Leskowsky
Dennis A. Urban

426 during the October 2025 accounting close period through its established process for making accounting corrections.

- B. Bank Charges are recorded to Account 923 "Outside services employed".

Total amounts for the 12 months ended June 30, 2021, through the HTY are \$1.7 million. See I&E-RE-I-12-D Attachment 1 for all bank charges recorded to Account 921 for the 12 months ended June 30, 2021, through the HTY. The attachment also lists \$0.2 million in bank rebates received by PPL Electric in relation to its US Bank P-Card program. These are all allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8.

The budget for the FTY is \$0.9 million and for the FPFTY is \$0.9 million. Charges of this type are reflected in customer rates based on the FERC account to which they are recorded and the definition of that FERC account. These are all allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8. These are reasonable and prudent costs incurred and associated with, among other things, bank analysis fees, wire fees, and Issuing and Paying Agent (IPA) fees, all of which are necessary to finance Company activities, and thus are appropriately included in the Company's distribution rates.

- C. Financing fees are recorded to Account 923 "Outside services employed".

Total amounts for the 12 months ended June 30, 2021, through the HTY are \$677,971. See I&E-RE-I-12-D Attachment 1 for all financing fees recorded to Account 923 or 930 for the 12 months ended June 30, 2021, through the HTY. These are all allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8.

The budget for the FTY is \$0.1 million and for the FPFTY is \$0.1 million. These are all of allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the

WITNESS: Sharon Leskowsky
Dennis A. Urban

Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8.

Payment transaction fees are recorded to Account 910 "Miscellaneous customer service and informational expenses".

The Company did not incur any payment transaction fees for the 12 months ended June 30, 2021, through the HTY.

The budget for the FTY is \$0.0 million and for the FPFTY is \$5.2 million. The FPFTY claim is based on PPL Electric's proposal to recover payment transaction fees through base rates as described in PPL Electric Statement No. 18. See PPL Electric Statement No. 18 for an explanation as to why these costs are appropriate to recover in the Company's base rates. These are reasonable and prudent costs incurred and associated with rating agencies and bond trustee fees required to finance Company activities, and thus are appropriately included in the Company's distribution rates. Charges of this type are reflected in customer rates based on the FERC account to which they are recorded and the definition of that FERC account.

- D. Subscriptions are recorded to Account 921 "Office supplies and expenses" and various other expense accounts as shown in I&E-RE-I-12-D Attachment 1.

Total amounts for the 12-months ended June 30, 2021, through the HTY were \$683,915. See I&E-RE-I-12-D Attachment 1 for subscription expenses charged to Budget Item 26010 (Subscriptions & Publications) for subscriptions for the 12-months ended June 30, 2021, through the HTY. This includes \$402,563 of allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8.

The budget for the FTY is \$120,840 and for the FPFTY is \$73,674. Charges of this type are reflected in customer rates based on the FERC account to which they are recorded and the definition of that FERC account. This includes allocated costs of \$119,692 for FTY and \$72,684 for FPTY which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8. These are reasonable and prudent costs incurred and associated with, among other things, subscriptions to

WITNESS: Sharon Leskowsky
Dennis A. Urban

news organizations for employee research and training, employee training and development organization resources, and workplace tools and thus are appropriately included in distribution ratemaking.

- E. Company sponsorships are recorded to Account 930 "Advertising & Misc General".

The total amount for the 12 months ended June 30, 2021, through the HTY was \$119,930. These were all allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8. See I&E-RE-I-12-D Attachment 1 for company sponsorships charged to Activity Code 000001C039 (Sponsorships – PA Only) for sponsorships for the 12 months ended June 30, 2021, through the HTY.

The budget for the FTY is \$41,300 and for the FPFTY is \$27,510. These are all allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8. Charges of this type are reflected in customer rates based on the FERC account to which they are recorded and the definition of that FERC account. These are reasonable and prudent costs incurred and associated with, among other things, PPL Electric's community and economic development sponsorships, which are strategic investments that promote the long-term health and economic vitality of the communities it serves. These efforts help attract and retain businesses, support workforce development, and strengthen local economies, which benefits all customers by fostering load stability and spreading fixed costs across a broader base, and thus are appropriately included in distribution ratemaking.

- F. Lobbying expenses/Political campaign donations are recorded to "Other income and (deductions)," Account 426, and not to operating expenses. Therefore, contributions of this type are not reflected in customer rates.

- G. Membership dues and subscriptions are recorded to Account 930 "Advertising & Misc General".

The total amount for the 12 months ended June 30, 2021, through the HTY was \$7.1 million. This includes \$405,204 of allocated costs which have been calculated based on historical allocation

WITNESS: Sharon Leskowsky
Dennis A. Urban

percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8. See I&E-RE-I-12-D Attachment 1 for membership dues charged to Budget Item 47000 (Contrib, Dues & Membership Fee) for membership dues for the 12-months ended June 30, 2021, through the HTY.

The budget for the FTY is \$1.4 million and for the FPFTY is \$2.8 million. This includes \$0.1 million for FTY and FPFTY of allocated costs which have been calculated based on historical allocation percentages contained within the Company's records and in accordance with the Company's Cost Allocation Manual (CAM) provided in filing requirement II-D-8. Charges of this type are reflected in customer rates based on the FERC account to which they are recorded and the definition of that FERC account.

In preparation of this response, PPL Electric has identified approximately \$4,000 in Tab G of I&E-Re-I-12-D Attachment 1 across the 12-months ended June 30, 2021, through the HTY that should not have been included, as they relate to a private social organization. The remainder of the charges for the historic periods and the FTY and FPFTY are reasonable and prudent costs incurred and associated with, among other things, memberships to chambers of commerce, employee training and professional development organizations, industry groups and associations, work-related travel, and online working tools and thus are appropriately included in distribution ratemaking.

- H. Donations are recorded to "Other income and (deductions)," Account 426, and not to operating expenses. Therefore, contributions of this type are not reflected in customer rates.
- I. Charitable and civic contributions are recorded to "Other income and (deductions)," Account 426, and not to operating expenses. Therefore, contributions of this type are not reflected in customer rates.

WITNESS: Dennis A. Urban Jr.

PPL Electric Utilities Corporation
Response to the Set XII Data Requests of the
Office of Consumer Advocate (OCA)
Dated November 20, 2025
Docket No. R-2025-3057164

OCA XII-11	Refer to Attachment II-D-7a. Please explain what caused the \$1,409,000 increase in Membership Dues and provide the supporting documentation showing the derivation of the Membership Dues of \$2,878,000 for 2027.
PPL Electric Response	PPL Electric found a timing item when providing this response. In the 2027 forecast, a higher amount was forecasted in the first quarter related to the timing of payments. This overstated the FPFTY by \$808,339. The remaining increase in membership dues is associated with updated amounts for the 2026 and 2027 calendar year forecast. This has been corrected in OCA I-1 Attachment 231 SUPPLEMENTAL.

WITNESS: Dennis A. Urban Jr.

PPL Electric Utilities Corporation
Response to the Set XXV Data Requests of the
Office of Consumer Advocate (OCA)
Dated December 4, 2025
Docket No. R-2025-3057164

OCA XXV-23

Refer to the response to I&E-RE-II-8-D Attachment 1. Please identify the functional groups that used the 5% vacancy reserve.

PPL Electric
Response

In reference to I&E-RE-II-3-D, the functional groups that used a 5% vacancy reserve were:

- Customer Service
- Financial Planning and Analysis
- Communications
- Public Affairs
- Facilities

WITNESS: Dennis A. Urban
Sharon Leskowsky

PPL Electric Utilities Corporation
Response to the RE Set II Data Requests of the
Bureau of Investigation and Enforcement
Dated October 14, 2025
Docket No. R-2025-3057164

I&E-RE-II-17-D

Reference PPL Exhibit II-D-7, Attachment II-D-7d concerning advertising expense. Provide the following:

- A. Detailed breakdown and description of each type of advertising under Goodwill or institutional advertising:
 - 1. FPFTY 2027 – \$130,000.
- B. Detailed breakdown and description of each type of advertising under Customer assistance programs:
 - 1. HTY 2025 – \$128,000
 - 2. FPFTY 2027 - \$100,000.
- C. Detailed breakdown and description of each type of advertising under Customer Education:
 - 1. HTY 2025 – \$110,000.
 - 2. FPFTY 2027 – \$500,000.
- D. Detailed breakdown and description of each type of advertising under Miscellaneous:
 - 1. HTY 2025 – \$262,000.
 - 2. FPFTY 2027 – \$193,000.
- E. Samples for each of the advertising programs listed in response to Parts A through D, including, but not limited to brochures, notices, bill inserts, maintenance tips, and publications provided to customers under each of these advertising programs.

WITNESS: Dennis A. Urban
Sharon Leskowsky

PPL Electric
Response

A. HTY 2025 – \$49,400

Winter 2024 holiday campaign and Lehigh Valley Business Women of Influence of advertisement

- FPFTY 2027 - \$130,000

Through its Partners In Power campaign, PPL Electric aims to build trust and community connection that is rooted in partnership. By demonstrating the value behind investments that help safeguard reliability and build communities that thrive as well as to provide support through available tools, programs and resources that help them take control of their energy use and manage their bills, this campaign is the key mechanism to reach customers.

- The campaign would be deployed across a broad mix of channels, with tailored messages for each:
 - Broadcast Media (TV & Radio)
 - Purpose: Reach broad audiences with emotionally resonant stories.
 - Benefits: High reach, strong emotional impact, credibility.
 - Target: General public, older demographics, rural customers.
 - Digital Advertising (Display, Video, Social Media)
 - Platforms: Meta (Facebook/Instagram), YouTube, LinkedIn, streaming services, Programmatic Display.
 - Benefits: Precision targeting, measurable engagement, mobile-friendly.
 - Target: Younger and middle-aged customers, urban/suburban, tech-savvy users.
 - Owned Media (Website, Blog, Email)
 - Benefits: Deep engagement, SEO value, trust-building, audience targeting
 - Target: Customers seeking information, business partners, educators.
 - Out-of-Home (OOH) & Transit Advertising
 - Locations: Billboards, bus shelters, EV charging stations

WITNESS: Dennis A. Urban
Sharon Leskowsky

- Benefits: High visibility, message reinforcement.
- Target: Commuters, urban dwellers, passive audiences.

B.

- HTY 2025 – \$7,500

Paid digital ads promoting LIHEAP were deployed on Meta (Facebook and Instagram) targeting PPL Electric Utilities customers.

- FPFTY 2027 - \$100,000.

Through an appropriate mix of marketing channels that are aligned to key customer groups who may qualify for or need assistance due to financial hardship, PPL Electric will deploy a recurring marketing campaign to reach customers in channels where they are. The campaign is tailored to customers who need help paying their bill and promotes the programs and payment arrangements available to help every family in need, regardless of income. (Payment arrangements, CARES, OnTrack, WRAP, LIHEAP, Operation HELP, Budget Billing)

- Paid and owned/earned channels will be used to effectively target key PPL Electric customer segments. Anticipated channels include and are not limited to:
 - Digital Advertising (Display, Video, Social Media)
 - Platforms: Meta (Facebook/Instagram), YouTube, LinkedIn, Programmatic Display.
 - Benefits: Precision targeting, measurable engagement, mobile-friendly.
 - Target: Younger and middle-aged customers, urban/suburban, tech-savvy users. Customers seeking information, income-eligible and customers facing temporary financial hardship.
 - Owned Media (Website, Blog, Email)
 - Benefits: Deep engagement, SEO value, trust-building, audience targeting
 - Target: Customers seeking information, income-eligible and

WITNESS: Dennis A. Urban
Sharon Leskowsky

customers facing temporary financial hardship.

- Out-of-Home (OOH) & Transit Advertising
 - Locations: Billboards, bus shelters, EV charging stations
 - Benefits: High visibility, message reinforcement.
 - Target: Income-eligible and customers facing temporary financial hardship. Commuters, urban dwellers, passive audiences who may need assistance or know someone who can benefit from assistance.

C.

- HTY 2025 – \$100,110

Paid digital campaigns were deployed on Meta (Facebook and Instagram) and Google. The ads promoted the following:

- Ease of doing business and digital tools: Creating an online account, resources to help manage the bill, start/stop/transfer service, paperless billing, variety of ways to pay, emergency preparedness, PPL Electric alerts, Seasonal Saving Solutions, shopping for a supplier, regional open houses, vegetation management and system maintenance, and a winter holiday campaign
 - Digital Advertising (Display, Video, Social Media)
 - Platforms: Meta (Facebook/Instagram), Google Ads
 - Benefits: Precision targeting, measurable engagement, mobile-friendly.
 - Target: Geotargeted to PPL Electric Utilities customers

- FPFTY 2027 – \$500,000.

Through its Partners in Power campaign, PPL Electric aims to educate its customers regarding reliability, affordability, ease of doing business and safety.

WITNESS: Dennis A. Urban
Sharon Leskowsky

- The campaign would expand the channel mix as compared to 2025, and includes a broad mix of paid channels including but not limited to:
 - Broadcast Media (TV & Radio)
 - Purpose: Reach broad audiences with emotionally resonant stories.
 - Benefits: High reach, strong emotional impact, credibility.
 - Target: General public, older demographics, rural customers.
 - Digital Advertising (Display, Video, Social Media, Influencer Marketing)
 - Platforms: Meta (Facebook/Instagram), YouTube, LinkedIn, streaming services, Programmatic Display.
 - Benefits: Precision targeting, measurable engagement, mobile-friendly.
 - Target: Younger and middle-aged customers, urban/suburban, tech-savvy users.
 - Owned Media (Website, Blog, Email)
 - Benefits: Deep engagement, SEO value, trust-building, audience targeting
 - Target: Customers seeking information, business partners, educators.
 - Out-of-Home (OOH) & Transit Advertising
 - Locations: Billboards, bus shelters, EV charging stations
 - Benefits: High visibility, message reinforcement.
 - Target: Commuters, urban dwellers, passive audiences.

D.

- HTY 2025 – \$110,266

These charges include advertising agency production costs and fees.

- FPFTY 2027 – \$193,000.

This would include advertising agency production costs and fees as well as any emergent communications requiring paid marketing.

WITNESS: Dennis A. Urban
Sharon Leskowsky

E.

Samples of HTY 2025 for each of the advertising programs listed in response to Parts A through D, including, but not limited to brochures, notices, bill inserts, maintenance tips, and publications provided to customers under each of these advertising programs are attached. FPFTY 2027 – Future marketing samples are not yet available.

See:

Part A Good-will Institutional

- I&E-RE-II-17 Attachment 1
- I&E-RE-II-17 Attachment 2
- I&E-RE-II-17 Attachment 3

Part B Customer Assistance

- I&E-RE-II-17 Attachment 4
- I&E-RE-II-17 Attachment 26
- I&E-RE-II-17 Attachment 27

Part C Customer Education

- I&E-RE-II-17 Attachment 5
- I&E-RE-II-17 Attachment 6
- I&E-RE-II-17 Attachment 7
- I&E-RE-II-17 Attachment 8
- I&E-RE-II-17 Attachment 9
- I&E-RE-II-17 Attachment 10
- I&E-RE-II-17 Attachment 11
- I&E-RE-II-17 Attachment 12
- I&E-RE-II-17 Attachment 13
- I&E-RE-II-17 Attachment 14
- I&E-RE-II-17 Attachment 15
- I&E-RE-II-17 Attachment 16
- I&E-RE-II-17 Attachment 17
- I&E-RE-II-17 Attachment 18
- I&E-RE-II-17 Attachment 19
- I&E-RE-II-17 Attachment 20
- I&E-RE-II-17 Attachment 21
- I&E-RE-II-17 Attachment 22
- I&E-RE-II-17 Attachment 23

WITNESS: Dennis A. Urban
Sharon Leskowsky

- I&E-RE-II-17 Attachment 24
- I&E-RE-II-17 Attachment 25
- I&E-RE-II-17 Attachment 28
- I&E-RE-II-17 Attachment 29
- I&E-RE-II-17 Attachment 30
- I&E-RE-II-17 Attachment 31
- I&E-RE-II-17 Attachment 32
- I&E-RE-II-17 Attachment 33

Part D Future marketing samples are not yet available.

PPL ELECTRIC UTILITIES CORPORATION
Forecast July 2025 - June 2026
(Thousands of Dollars)

	1st Q	2nd Q	3rd Q	4th Q	12 months
PPL Electric Consolidated	Actuals				
Operating Revenues					
Electric Revenue	\$786,070	\$831,595	\$948,327	\$780,973	\$3,346,966
Wholesale Energy Marketing					
Intercompany Sales					
Total Operating Revenues	786,070	831,595	948,327	780,973	3,346,966
Operating Expenses					
Electric Fuel					
Energy Purchases - External	224,386	282,190	342,413	242,815	1,091,805
Energy Purchases - Internal					
Total Fuel & Energy Purchases	224,386	282,190	342,413	242,815	1,091,805
Other Operating Expenses - Direct	162,450	98,692	105,471	97,415	464,029
Other Operating Expenses - Intercompany	(2,097)	42,064	48,369	48,923	137,259
Total O&M Expense	160,353	140,756	153,841	146,338	601,288
Amort. of Transition Costs/Def Credits					
Depreciation	104,827	106,007	106,636	109,624	427,094
Taxes Other Than Income	37,577	36,498	41,348	32,438	147,861
Total Operating Expenses	527,143	565,452	644,238	531,214	2,268,047
Income from Operations	258,927	266,143	304,089	249,759	1,078,919
Other Income and (Deductions)	16,763	16,513	11,431	10,473	55,179
Interest Expense					
Long Term Debt	65,346	69,129	68,430	73,346	276,251
Preferred Securities		1,093	1,087	1,122	3,302
Short Term Debt & Other	5,585		96	326	6,007
Intercompany Interest					
AFUDC & Capitalized Interest	(3,648)	(3,541)	(2,853)	(3,166)	(13,209)
Total Interest Expense	67,283	66,680	66,759	71,629	272,351
Income Before Income Taxes	208,407	215,976	248,761	188,603	861,747
Income Taxes					
Federal Income Tax	25,970	16,317	23,426	11,211	76,924
State Income Tax	8,531	4,743	7,073	2,363	22,710
Deferred Income Taxes	15,248	33,786	28,680	29,244	106,957
Total Income Taxes	49,749	54,845	59,179	42,819	206,591
Income Before Extraordinary Item	158,658	161,131	189,582	145,785	655,156
Extraordinary Item, net of income taxes					
Net Income	158,658	161,131	189,582	145,785	655,156
Noncontrolling Interest					
Minority Interest					
Preferred Stock Dividend Requirements					
Net Income Attributable to Noncontrolling Interest					
Earnings Available for Common	\$158,658	\$161,131	\$189,582	\$145,785	\$655,156

PPL ELECTRIC UTILITIES CORPORATION
Forecast July 2026 - June 2027
(Thousands of Dollars)

	1st Q	2nd Q	3rd Q	4th Q	12 months
PPL Electric Consolidated					
Operating Revenues					
Electric Revenue	\$836,188	\$850,275	\$963,520	\$798,960	\$3,448,943
Wholesale Energy Marketing					
Intercompany Sales					
Total Operating Revenues	836,188	850,275	963,520	798,960	3,448,943
Operating Expenses					
Electric Fuel					
Energy Purchases - External	274,335	283,366	343,990	244,530	1,146,222
Energy Purchases - Internal					
Total Fuel & Energy Purchases	274,335	283,366	343,990	244,530	1,146,222
Other Operating Expenses - Direct	124,575	115,662	116,037	104,959	461,232
Other Operating Expenses - Intercompany	49,824	52,066	51,816	47,875	201,581
Total O&M Expense	174,399	167,728	167,852	152,834	662,813
Amort. of Transition Costs/Def Credits					
Depreciation	111,619	115,062	120,434	121,159	468,275
Taxes Other Than Income	39,378	40,154	45,086	36,266	160,884
Total Operating Expenses	599,731	606,310	677,362	554,790	2,438,194
Income from Operations	236,457	243,965	286,158	244,170	1,010,749
Other Income and (Deductions)	16,610	13,043	9,956	12,144	51,753
Interest Expense					
Long Term Debt	75,805	75,805	77,839	82,594	312,043
Preferred Securities	1,170	1,184	1,135	1,161	4,650
Short Term Debt & Other					
Intercompany Interest					
AFUDC & Capitalized Interest	(3,271)	(3,189)	(3,691)	(3,293)	(13,444)
Total Interest Expense	73,704	73,799	75,284	80,462	303,249
Income Before Income Taxes	179,362	183,208	220,830	175,852	759,252
Income Taxes					
Federal Income Tax	17,248	19,052	24,381	15,631	76,312
State Income Tax	4,691	5,386	6,087	2,956	19,120
Deferred Income Taxes	36,070	34,651	36,558	36,722	144,001
Total Income Taxes	58,010	59,089	67,026	55,308	239,433
Income Before Extraordinary Item	121,352	124,119	153,804	120,544	519,819
Extraordinary Item, net of income taxes					
Net Income	121,352	124,119	153,804	120,544	519,819
Noncontrolling Interest					
Minority Interest					
Preferred Stock Dividend Requirements					
Net Income Attributable to Noncontrolling Interest					
Earnings Available for Common	\$121,352	\$124,119	\$153,804	\$120,544	\$519,819

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Balance Sheet at

June 30, 2027

Assets and Other Debits

(Thousands of Dollars)

Acct.		REBUTTAL
<u>No.</u>	<u>Title of Account</u>	<u>Amount</u>
	Utility Plant	
101	Plant in service	\$ 16,240,345
105	Plant held for future use	19,928
106	Completed construction not classified	4,207,989
107	Construction work in progress	1,705,443
	Gross utility plant	22,173,705
108	Accumulated provision for depreciation	(5,071,778)
111	Accumulated provision for amortization	(69,173)
	Net utility plant	17,032,754
	Other Property and Investments	
121	Nonutility property	18,556
122	Accumulated provision for depreciation of nonutility property	(20)
	Net nonutility property	18,536
123	Investment in subsidiary companies	0
124	Other investments	0
128	Other special funds	0
	Total Other Property and Investments	18,536
	Current and Accrued Assets	
131	Cash	0
132	Interest special deposits	0
134	Other special deposits	0
135	Working funds	0
136	Temporary cash investments	33,922
	Notes and accounts receivable	
141	Notes receivable	0
142	Customer accounts receivable	457,442
143	Other accounts receivable	36,739
144	Accumulated provision for uncollectible accounts-credit	(39,303)
	Total notes and accounts receivable	454,878
145	Notes receivable from associated companies	56,068
146	Accounts receivable from associated companies	0
	Materials and supplies	
154	Plant materials and operating supplies	100,823
158	Allowances and environmental credits	3
163	Stores expense undistributed	8,466
	Total materials and supplies	109,292

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Balance Sheet at
June 30, 2027
Assets and Other Debits
(Thousands of Dollars)

Acct.		REBUTTAL
No.	Title of Account	Amount
	Current and Accrued Assets (continued)	
165	Prepayments	\$ 103,510
	Other current and accrued assets	
171	Interest and dividends receivable	157
172	Rents receivable	11,479
173	Accrued utility revenues	127,474
174	Miscellaneous current and accrued assets	33,592
	Total other current and accrued assets	<u>172,702</u>
	Total Current and Accrued Assets	<u>930,372</u>
	Deferred Debits	
181	Unamortized debt expense	54,551
182.3	Other regulatory assets	862,825
183	Preliminary survey and investigation charges	153
184	Clearing accounts	359
185	Temporary facilities	0
186	Miscellaneous deferred debits	103,059
189	Unamortized loss on reacquired debt	1,745
190	Accumulated deferred income taxes (noncurrent)	372,338
	Total Deferred Debits	<u>1,395,030</u>
	Total Assets and Other Debits	<u>\$ 19,376,692</u>

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Balance Sheet at
June 30, 2027
Liabilities and Other Credits
(Thousands of Dollars)

Acct.		REBUTTAL
<u>No.</u>	<u>Title of Account</u>	<u>Amount</u>
	Proprietary Capital	
201	Common stock issued	\$ 367,509
204	Preferred stock issued	0
207	Premium on capital stock	0
211	Miscellaneous paid-in capital	5,817,960
214	Capital stock expense	0
215.1	Appropriated retained earnings - amortization reserve - Federal	0
216	Unappropriated retained earnings	2,346,404
216.1	Unappropriated undistributed subsidiary earnings	0
217	Reacquired capital stock	0
219	Other comprehensive income	0
	Total Proprietary Capital	<u>8,531,873</u>
	Long-Term Debt	
221	Bonds	6,690,500
224	Other long-term debt	0
225	Unamortized premium	0
226	Unamortized discount on long-term debt-debit	<u>(37,781)</u>
		6,652,719
	Less amount due within one year	
221	Bonds	<u>0</u>
	Total Long-Term Debt	<u>6,652,719</u>
	Other Noncurrent Liabilities	
227	Obligations under capital leases (noncurrent)	<u>0</u>
	Current and Accrued Liabilities	
224	Long-term debt due within one year-other	0
231	Notes payable	0
232	Accounts payable	498,400
234	Accounts payable to associated companies	58,414
235	Customer deposits	6,554
236	Taxes accrued	(3,656)
237	Interest accrued	80,260
238	Dividends declared	0
240	Matured interest	0
241	Tax collections payable	1,332
242	Miscellaneous current and accrued liabilities	102,621
243	Obligations under capital-leases - current	<u>0</u>
	Total Current and Accrued Liabilities	<u>743,925</u>

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Balance Sheet at
June 30, 2027
Liabilities and Other Credits
(Thousands of Dollars)

Acct.		REBUTTAL
No.	Title of Account	Amount
	Deferred Credits	
228.3	Accumulated provision for pensions and benefits	\$ 45,800
229	Accumulated provision for rate refunds	0
252	Customer advances for construction	0
253	Other deferred credits	74,701
254	Other regulatory liabilities	872,615
255	Accumulated deferred investment tax credits	265
281	Accumulated deferred income taxes - accelerated amortization property	0
282	Accumulated deferred income taxes - other property	2,298,553
283	Accumulated deferred income taxes - other (noncurrent)	156,241
	Total Deferred Credits	<u>3,448,175</u>
	Total Liabilities and Other Credits	<u>\$ 19,376,692</u>

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REBUTTAL Statement of Net Utility Operating Income
Year Ended June 30, 2027
(Thousands of Dollars)

Acct. No.	<u>Title of Account</u>	REBUTTAL <u>Amount</u>
400	Operating Revenue (B-3)	<u>\$ 3,463,885</u>
	Operating Expenses:	
401,402	Operation and Maintenance expenses (B-4)	
	Power production	846,332
	Transmission	335,381
	Regional market	-
	Distribution	207,712
	Customer accounts	86,338
	Customer service and informational expenses	132,910
	Sales	-
	Administrative and general	168,914
	Total Operation and Maintenance Expenses	<u>1,777,588</u>
403	Depreciation expense	441,221
404,405	Amortization of electric plant	27,030
407.3	Regulatory debits	11,007
407.4	Regulatory credits	0
	Taxes (B-5)	
408.1	Taxes other than income taxes	159,956
409.1	Income taxes	24,752
	Deferred income taxes	
410.1	Provision	163,314
411.1	Provision - Credit	(17,150)
411.4	Investment tax credit adjustments	(31)
	Total Taxes	<u>330,841</u>
411.6	Gains from disposition of utility plant	-
411.7	Losses from disposition of utility plant	-
	Total Operating Expenses	<u>2,587,687</u>
	Net Utility Operating Income	<u><u>\$ 876,198</u></u>

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REBUTTAL Statement of Operation and Maintenance Expenses
Year Ended June 30, 2027
(Thousands of Dollars)

Acct. No.	<u>Title of Account</u>	REBUTTAL <u>Amount</u>
	<u>Power Production Expenses</u>	
	Other Power Supply Expenses	
555	Purchased power	
	Market-based from EWGs	\$ 844,328
	Non-utility generation	-
	PJM ancillary services	1,676
	Other	-
556	System control and load dispatching	
	PJM ancillary services	6
	Other	0
557	Other expenses	323
	Total Other Power Supply Expenses	<u>846,332</u>
	Total Power Production Expenses	<u>846,332</u>
	<u>Transmission Expenses</u>	
	Operation	
560	Operation supervision and engineering	5,631
561	Load dispatching	2,641
562	Station expenses	644
563	Overhead line expenses	1,192
564	Underground line expenses	-
565	Transmission of electricity by others	300,212
566	Miscellaneous transmission expenses	5,822
567	Rents	1,324
	Total Transmission Operation Expenses	<u>317,467</u>
	Maintenance	
568	Maintenance supervision and engineering	11
569	Maintenance of structures	16
569.1	Maintenance of Computer Hardware	23
569.2	Maintenance of Computer Software	2,133
569.3	Maintenance of Communication Equipment	77
570	Maintenance of station equipment	4,455
571	Maintenance of overhead lines	10,321
572	Maintenance of underground lines	151
573	Maintenance of miscellaneous transmission plant	726
574	Maintenance of Transmission Plant	-
	Total Transmission Maintenance Expenses	<u>17,914</u>
	Total Transmission Expenses	<u>335,381</u>

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REBUTTAL Statement of Operation and Maintenance Expenses
Year Ended June 30, 2027
(Thousands of Dollars)

Acct. No.	<u>Title of Account</u>	
	<u>Regional Market Expenses</u>	
	Operation	
575.7	Market Facilitation, Monitoring and Compliance Services	\$ -
	Total Regional Market Expenses	<u>-</u>
	<u>Energy Storage Expenses</u>	
	Operation	
577.1	Operation Supervision and Engineering	\$ -
	Total Energy Storage Operation Expenses	<u>-</u>
	Maintenance	
578.2	Maintenance of Energy Storage Equipment and Structures	\$ -
	Total Energy Storage Maintenance Expenses	<u>-</u>
	Total Energy Storage Expenses	<u>-</u>
	<u>Distribution Expenses</u>	
	Operation	
580	Operation supervision and engineering	10,367
581	Load dispatching	2,295
582	Station expenses	86
583	Overhead line expenses	29,067
584	Underground line expenses	6,594
585	Street lighting and signal system expenses	-
586	Meter expenses	2,391
587	Customer installations expenses	3,026
588	Miscellaneous distribution expenses	18,181
589	Rents	7,534
	Total Distribution Operation Expenses	<u>79,542</u>
	Maintenance	
590	Maintenance supervision and engineering	-
591	Maintenance of structures	137
592	Maintenance of station equipment	12,305
593	Maintenance of overhead lines	110,715
594	Maintenance of underground lines	340
595	Maintenance of line transformers	182
596	Maintenance of street lighting and signal systems	2,424
597	Maintenance of meters	-
598	Maintenance of miscellaneous distribution plant	2,067
	Total Distribution Maintenance Expenses	<u>128,171</u>
	Total Distribution Expenses	<u>207,712</u>

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REBUTTAL Statement of Operation and Maintenance Expenses
Year Ended June 30, 2027
(Thousands of Dollars)

Acct. No.	<u>Title of Account</u>	
	<u>Customer Accounts Expenses</u>	
	Operation	
901	Supervision	4,218
902	Meter reading expenses	1,206
903	Customer records and collection expenses	39,367
904	Uncollectible accounts	37,959
905	Miscellaneous customer accounts expenses	3,589
	Total Customer Accounts Expenses	<u>86,338</u>
	<u>Customer Service and Informational Expenses</u>	
	Operation	
908	Customer assistance expenses	
	On-track uncollectible accounts	\$ 40,718
	Other	92,192
909	Informational and instructional expense	-
910	Miscellaneous customer service and informational expenses	-
	Total Customer Service and Informational Expenses	<u>132,910</u>
	<u>Sales Expenses</u>	
	Operation	
911	Supervision	-
912	Demonstrating and selling expenses	-
913	Advertising expenses	-
916	Miscellaneous sales expenses	-
	Total Sales Expenses	<u>-</u>
	<u>Administrative and General Expenses</u>	
	Operation	
920	Administrative and general salaries	55,208
921	Office supplies and expenses	22,312
922	Administrative Expenses Transferred-Credit	(6,624)
923	Outside services employed	41,326
924	Property insurance	3,955
925	Injuries and damages	8,548
926	Employee pensions and benefits	3,005
928	Regulatory commission expenses	6,818
930	Miscellaneous general expenses	(11,733)
931	Service Company Rents	1,165
		<u>123,980</u>
	Maintenance	
935	Maintenance of general plant	<u>44,934</u>
	Total Administrative and General Expenses	<u>168,914</u>
	Total Operation and Maintenance Expenses	<u>\$ 1,777,588</u>

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REBUTTAL Statement of Detail - Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

<u>Line</u> <u>No.</u>	<u>Description</u>	<u>REBUTTAL</u> <u>Amount</u>
	Taxes Other Than Income	
	State and Local	
1	Gross Receipts	\$ 146,950
2	Local property and Other	4,278
3	Public Utility Realty	3,175
4	State Unemployment Compensation	104
5	Sales and Use	0
6	Total State and Local	<u>154,507</u>
	Federal	
7	Unemployment Tax Act	24
8	Social Security and Hospital Insurance	5,425
9	Total Federal	<u>5,449</u>
10	Total Taxes Other Than Income	<u>159,956</u>
	Income Taxes	
11	State	448
12	Federal	24,304
13	Total Income Taxes	<u>24,752</u>
	Investment Tax Credit	
14	Deferred	0
15	Amortization of Deferral	(31)
16	Net Investment Tax Credit	<u>(31)</u>

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
REBUTTAL Statement of Detail - Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Federal</u>	<u>REBUTTAL State</u>	<u>Amount</u>
	Deferred Income Taxes			
	Provision for Deferred Taxes			
	Net Book/Net Tax Plant Timing Differences:			
17	ACRS & MACRS - Distribution Property	34,501	0	34,501
18	Contributions in Aid of Construction (CIAC) - Transmission Property	418	135	553
19	Contributions in Aid of Construction (CIAC) - General Property	37	19	56
20	Net Book/Net Tax Pant - Transmission Property	64,357	30,687	95,044
21	Basis Adjustment - Distribution Property	19,245	6,975	26,220
22	Basis Adjustment - General Property	1,140	574	1,714
23	Federal NOL Carryforward - Distribution Property	0	0	0
24	State NOL Carryforward - Distribution Property	0	0	0
25	Deficient Federal NOL Deferred Taxes - Distribution Property	476	0	476
26	Deficient Federal NOL Deferred Taxes - Transmission Property	214	0	214
27	Bad Debts	61	23	84
28	Pension Benefits	2,736	1,022	3,758
29	Post-Employment Benefits	63	25	88
30	Post-Retirement VEBA	270	100	370
31	Prepays	172	64	236
32	Total Provision	<u>123,690</u>	<u>39,624</u>	<u>163,314</u>
	Provision for Deferred Taxes - Credit			
	Net Book/Net Tax Plant Timing Differences:			
33	ACRS & MACRS - General Property	(5,078)	(237)	(5,315)
34	Contributions in Aid of Construction (CIAC) - Distribution Property	(5,469)	(1,966)	(7,435)
35	Deferred Compensation - Officers	(76)	(29)	(105)
36	Environmental Cleanup	(32)	(12)	(44)
37	Loss - Reacquired Debt	(87)	(33)	(120)
38	Post-Retirement Benefits	(465)	(173)	(638)
39	Rate Case Expenses	(9)	(3)	(12)
40	Supplemental Executive Retirement Pension (SERP)	(56)	(21)	(77)
41	Service Company Temporary Costs	(278)	(104)	(382)
42	Vacation Pay	(56)	(21)	(77)
43	Storm Deferral	(2,147)	(798)	(2,945)
44	Total Credits	<u>\$ (13,753)</u>	<u>\$ (3,397)</u>	<u>(17,150)</u>
45	Total Deferred Income Taxes			<u>146,164</u>
46	Total All Taxes			<u>\$ 330,841</u>

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Rate Base and Rate of Return
12 Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Title of Account	REBUTTAL	
		Total T&D Operations	PPUC Jurisdictional (Exhibit BR-1)
	Electric Plant		
1	Electric plant in service (C-2)	\$ 20,346,787	\$ 10,176,107
1a	Electric plant in service (C-2) (IT Pro-forma)	25,880	25,880
2	Reserve for depreciation (C-2)	4,741,877	3,254,253
2a	Reserve for depreciation (C-2) (IT Pro-forma)	1,826	1,826
3	Net electric plant in service	<u>15,628,964</u>	<u>6,945,908</u>
	Additions		
4	Plant held for future use (C-3)	<u>0</u>	<u>0</u>
5	Total electric plant	<u>15,628,964</u>	<u>6,945,908</u>
	Working Capital		
6	Cash working capital (C-4)	713	16,462
7	Materials and operating supplies (C-5)	<u>109,289</u>	<u>72,146</u>
8	Total working capital	<u>110,002</u>	<u>88,608</u>
	Deductions		
9	Accumulated deferred taxes on income (C-6)	2,615,660	1,201,084
9a	Accumulated deferred taxes on income (C-6) (IT Pro-forma)	6,088	6,088
10	Customer advances for construction (B-1)	-	-
11	Customer deposits (B-1)	<u>6,554</u>	<u>6,554</u>
12	Total deductions	<u>2,628,302</u>	<u>1,213,726</u>
13	Rate Base (net)	<u>\$ 13,110,664</u>	<u>\$ 5,820,790</u>
	Pro forma return at present rates		
14	Amount (D-1, col. 6)		237,175
15	Percent		4.07%
	Pro forma return at proposed rates		
16	Amount (D-1, col. 8)		498,260
17	Percent		8.56%

NOTE: Totals may not tie due to rounding

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Electric Plant in Service - Original Cost
As of June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>REBUTTAL Amount</u>
1	Transmission	10,162,925
2	Distribution	9,139,143
3	General	1,069,930
4	Intangible	<u>670</u>
5	Total electric plant In service	\$20,372,668

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Reserve for Depreciation - Original Cost
As of June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>REBUTTAL Amount</u>
1	Transmission	\$1,484,404
2	Distribution	2,746,143
3	General	513,157
4	Intangible	-
5	Total reserve for depreciation	\$4,743,703

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Cash Working Capital
As of June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Amount</u>
1	Operation and maintenance expense (C-4, page 2)	\$ 6,786
2	Average prepayments (C-4, page 3)	13,421
3	Accrued taxes (C-4, page 4)	14,309
4	Interest payments (C-4, page 5)	<u>(33,803)</u>
5	Total cash working capital requirement	<u><u>\$ 713</u></u>

PPL Electric Utilities Corporation

REBUTTAL Working Capital Required for Operation and Maintenance Expenses

As of June 30, 2027

(Thousands of Dollars)

The Company bills its customers every month. On this basis, there is a considerable span of days between the time electricity is furnished to a customer and the time the customer pays for such electricity.

In many instances, the Company must pay its bills for payroll and other O&M expenses prior to the time it is able to collect the amount due for the service which requires the incurrance of such expenses. Thus, the Company has examined its records to determine, as to the major categories of expense, the average span of days which exists between the time an expense is incurred and the time it must be paid. Schedule C-4, page 2, of Exhibit Historic 1 sets forth the individual components which result in the days lag between payment of expenses and receipt of the related revenues used in the determination of the working capital required for the pro forma O&M expense for the test year ending June 30, 2025.

<u>Line No.</u>	<u>Description</u>	<u>Amount</u>
1	Net pro forma O&M expense (a)	485,640
2	O&M expense per day (line 1 divided by 365 days)	1,331
3	Average lag in days between payment of O&M expenses and receipt of revenue (b)	5.1
4	Working capital requirement (line 2 x line 3)	<u>\$ 6,786</u>
(a) Total pro forma operation and maintenance expense (D-1 col. 5 lines 2-4)		1,053,766
Less: Non-cash items		
	Uncollectible accounts expense	14,735
	Deferred Storm Outage Costs (D-9)	3,779
	Deferred IIJA Costs (D-10)	211
	Depreciation (D-1 col. 5 line 3)	<u>549,401</u>
	Net pro forma O&M expense	<u>\$ 485,640</u>

(b) See Exhibit Historic 1, Schedule C-4, page 2.

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Average Prepayments
As of June 30, 2027
(Thousands of Dollars)

Line No.	<u>Month</u>	<u>Insurance</u>	<u>PUC Annual Assessment</u>	<u>Other</u>	<u>Total</u>
1	July 2026	\$3,648	\$3,850	\$6,680	\$14,178
2	August 2026	3,014	3,500	6,527	\$13,041
3	September 2026	2,815	5,726	6,373	\$14,914
4	October 2026	2,188	5,089	6,345	\$13,623
5	November 2026	1,561	4,453	6,265	\$12,279
6	December 2026	960	3,817	6,007	\$10,784
7	January 2027	5,283	3,181	6,252	\$14,717
8	February 2027	4,614	2,354	6,546	\$13,514
9	March 2027	3,944	1,765	7,956	\$13,665
10	April 2027	3,489	1,177	9,065	\$13,731
11	May 2027	4,988	588	8,807	\$14,384
12	June 2027	4,410	(0)	8,411	\$12,821
13	July 2027	4,410	(0)	8,411	\$12,821
14	Total Prepayments	<u>\$45,323</u>	<u>\$35,501</u>	<u>\$93,645</u>	<u>\$174,470</u>
15	Monthly Average	<u>\$3,486</u>	<u>\$2,731</u>	<u>\$7,203</u>	<u>\$13,421</u>

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Accrued Taxes
Year Ended June 30, 2027
(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>	<u>Amount</u>	<u>12-Month Accrued Factor (a)</u>	<u>Accrued Taxes</u>
1	Federal income tax (D-1, line 6, col. 5)	16,330	-11.62%	(\$1,898)
2	PA income tax (D-1, line 7, col. 5)	(2,991)	-9.54%	285
3	PA gross receipts tax (D-16, page 3)	56,151	27.96%	15,700
4	PA capital stock tax (D-16, page 2)	0	0.00%	0
5	PA public utility reality tax (D-16, page 4)	3,110	7.13%	222
6	Total accrued taxes			<u>\$14,309</u>

- (a) The 12-month average factor represents, in the case of Federal and State income tax and capital stock tax, the portion of the tax liability which is available to the Company for the payment of other costs. This situation exists because revenue is available from customers prior to payment dates of the tax. The factors for the other Pennsylvania taxes represent the portions of those tax liabilities which must be provided by the Company due to payment of the taxes before the revenue is available from customers. Exhibit Historic 1, Schedule C-4, pages 6 through 11 reflect the computation of such factors.

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Interest Payments

As of June 30, 2027

(Thousands of Dollars)

<u>Line No.</u>	<u>Description</u>		<u>Amount</u>
1	Rate Base at June 30, 2027 (C-1)		\$ 13,110,664
2	Long-term debt ratio (B-8)		43.95%
3	Embedded cost of long-term debt (B-8)		5.08%
4	Pro forma interest (line 1 x line 2 x line 3)		<u>292,368</u>
5	Daily amount (line 4 ÷ 365)		<u>\$ 801</u>
6	Days to mid-point of interest payments	90.0	
7	Less: Revenue lag days (Historic C-4, page 2)	<u>47.8</u>	
8	Interest payments lag days (line 6 - line 7)		<u>42.2</u>
9	Total interest payments (line 5 x line 8)		<u>\$ 33,803</u>

PPL Electric Rebuttal Exhibit No. 1
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PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Operating Income
Pro Forma at Present and Proposed Rates
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Total Amount Per Books	Less: Automatic Cost Recovery Clauses/Riders ¹⁾	T & D Operations Per Books	Pro Forma Adjustments (D-2)	T & D Pro Forma at Present Rates	Pro Forma at Present Rates (Exhibit BR-1)	PPUC Jurisdictional Rate Increase (D-17, Pg. 4)	Pro Forma at Proposed Rates
1a	Rate Revenue	\$ 2,425,354	\$ (1,419,586)	\$ 1,005,768	\$ 4,723	\$ 1,010,491	\$ 1,010,491	\$ 384,522	\$ 1,395,013
1b	Other Non-Rate Revenue	1,038,531	(965)	1,037,566	0	1,037,566	60,129	1,699	61,828
1c	Total Operating Revenue	3,463,885	(1,420,551)	2,043,334	4,723	2,048,057	1,070,620	386,221	1,456,841
	Operating Expenses								
2	Operation and Maintenance	1,777,588	(1,276,262)	501,326	(952)	500,374	427,131	7,532	434,664
3	Depreciation	468,251	0	468,251	81,150	549,401	324,156	0	324,156
4	Regulatory Debits/Credits	11,007	(11,007)	0	3,990	3,990	3,990	0	3,990
	Provision for Taxes								
5	Taxes Other Than Income	159,956	(90,524)	69,432	(372)	69,060	64,973	22,408	87,382
	Income Taxes								
6	Federal	24,304	(8,329)	15,975	355	16,330	(22,540)	69,402	46,862
7	State	448	(3,096)	(2,648)	(343)	(2,991)	(10,721)	25,795	15,074
8	Deferred Income Taxes	146,164	0	146,164	(9,629)	136,535	46,470	0	46,470
9	Investment Tax Credit	(31)		(31)	0	(31)	(15)	0	(15)
10	Total Taxes	330,841	(101,949)	228,892	(9,989)	218,903	78,168	117,605	195,773
11	(Gain)/Loss from Disposition of Utility Plant	0	0	0	0	0	0	0	0
12	Total Operating Expenses	2,587,687	(1,389,217)	1,198,470	74,199	1,272,669	833,445	125,137	958,582
13	Operating Income	<u>\$ 876,198</u>	<u>\$ (31,334)</u>	<u>\$ 844,864</u>	<u>\$ (69,476)</u>	<u>\$ 775,388</u>	<u>\$ 237,175</u>	<u>\$ 261,084</u>	<u>\$ 498,260</u>

¹⁾ Automatic Recovery Clauses/Riders include CER, TCJA, SMR-2, DSIC, GSC-1, GSC-2, MFC, TSC, USR, ACR, and SDER for line 1, and GSC-1, GSC-2, MFC, TSC, USR, ACR, and SDER for all other lines.

NOTE: Totals may not tie due to rounding

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustments to Income
12 Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Reference	Description	REBUTTAL Amount
		<u>Operating Revenues</u>	
1	D-3 and D-4	Operating Revenue	\$ 4,723
		<u>Operation and Maintenance Expenses</u>	
2	D-5	Employee wages and benefits (D-5 Line 5 + Line 6)	(518)
3	D-6	Rate case expense	733
4	D-7	Economic Development Proposal Adjustment	400
5	D-8	Competitive Enhancement Charge Adjustment	-
6	D-9	Deferred Storm Expenses Adjustment	3,779
7	D-10	IIJA Expense Deferral Adjustment	211
8	D-11	USR Salaries Adjustment	(1,400)
9	D-12	Interest Expense on Customer Deposits	300
10	D-13	Company Use Generation Supply Purchase	1,359
11	D-14	Capital Treatment of Certain IT Expenditures	(1,826)
12		Total operation and maintenance expense	3,038
		<u>Depreciation</u>	
13	D-14	Capital Treatment of Certain IT Expenditures	1,826
14	D-15	Annual depreciation expense	79,324
15		Total depreciation expense	81,150
		<u>Provision for Taxes</u>	
		Taxes other than income	
16		Capital stock	0
17	D-16	Gross receipts	(275)
18	D-16	Public utility realty	(65)
19	D-5	Payroll taxes	(32)
		Income taxes	
20	D-17	Federal	355
21	D-17	State	(343)
22	D-18	Deferred income taxes	(9,629)
23			
23	D-19	Investment tax credit - amortization	0
24		Total Taxes	(9,989)
25		Gain and losses on property dispositions	0
26		Total Operating Expenses	74,199
27		Total Adjustments to Income	\$ (69,476)

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustments to Operating Revenue
Period Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	(1) Total Per Books	(2) Less: Automatic Cost Recovery Clauses/Riders ^{a)}	(3) T&D Operations Per Books	(4) Pro Forma Adjustments	(5) T&D Pro forma at Present Rates
1	Distribution revenue	\$ 1,188,312	\$ (183,073)	\$ 1,005,239	\$ 4,933 ^{b)}	\$ 1,010,172
2	Transmission Service Charge (TSC) revenue	325,313	(325,313)	0	0	0
3	Generation Service Charge (GSC) Revenue	915,486	(915,486)	0	0	0
4	State Tax Surcharge (STAS) revenue	(4,707)	4,707	-	0	-
5	Sales for Resale	319	0	319	0	319
6	Total Rate Revenue	<u>\$ 2,424,723</u>	<u>\$ (1,419,164)</u>	<u>\$ 1,005,558</u>	<u>\$ 4,933</u>	<u>\$ 1,010,491</u>
<u>Other Electric Revenue</u>						
7	Late Payment	15,306	0	15,306	0	15,306
8	Misc. Revenue	970	0	970	0	970
9	Rent	43,746	0	43,746	0	43,746
10	Other	978,510	(965)	977,545	0	977,545
11	Total Other	<u>\$ 1,038,531</u>	<u>\$ (965)</u>	<u>\$ 1,037,566</u>	<u>\$ -</u>	<u>\$ 1,037,566</u>
12	Operating Revenue (excl. unbilled)	3,463,254	(1,420,130)	2,043,124	4,933	2,048,057
13	Unbilled Revenue (D-4)	631	(422)	210	(210)	0
14	Total Operating Revenue	<u><u>\$ 3,463,885</u></u>	<u><u>\$ (1,420,551)</u></u>	<u><u>\$ 2,043,334</u></u>	<u><u>\$ 4,723</u></u>	<u><u>\$ 2,048,057</u></u>

^{a)} Automatic Recovery Clauses/Riders include GSC-1, GSC-2, MFC, TSC, TCJA, STAS, USR, ACR, CER, SDER, SMR and DSIC.^{b)} This adjustments is for annualization.

PPL Electric Rebuttal Exhibit No. 1
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PPL Electric Utilities Corporation
REBUTTAL 12 month Period Ended June 30, 2027 Budget with Annualization

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
Line Number	Rate Schedule	Number of Bills (monthly)	Sales (KWH)	Budgeted Base Distribution Rate Revenue	Smart Meter Rider (SMR)	Universal Service Rider (USR)	Act 129 Compliance Rider (ACR)	Competitive Enhancement Rider (CER)	Distribution System Improvement Charge (DSIC)	Storm Damage Expense Rider (SDER)	Tax Reform (TCJA)	Transmission Service Charge (TSC)	Generation Service Charge (GSC)	Present Rate Revenue	State Tax Adjustment Surcharge (STAS)	State Tax Adjustment Surcharge (STAS)	State Tax Adjustment Surcharge (STAS)	Total Revenue
				Note 1	Note 1		Note 1	Note 1	Note 1	Note 1	Note 1				Total	Distribution	Other	
1	RS	1,300,277	14,215,929.792	\$ 624,533.916	\$ 19,385.376	\$ 140,870.796	\$ 27,348.122	\$ -	\$ 65,570.906	\$ 8,634.419	\$ (44,201.747)	\$ 267,802.749	\$ 745,093.201	\$ 1,854,837.738	\$ (3,443.541)	\$ (3,453.806)	\$ 10,065	\$ 1,851,394.197
2	RTS	11,564	230,938,029	7,972,442	172,408	2,288,209	444,434		789,875	140,221	(486,048)	3,520,431	9,802,025	24,643,997	(41,827)	(41,958)	131	24,602,170
3	GS-1	147,382	1,842,773.827	78,763.076	4,416.931		4,406,905		6,248,127	553,807	(4,832,370)	18,295,829	59,606,199	167,458,504	(326,623)	(327,401)	778	167,131,881
4	GS-3	39,839	8,237,505.853	129,185.677	1,193.921		19,696,425		10,846,455	2,475,907	(7,932,518)	30,318,865	81,553,309	267,338,041	(566,243)	(567,301)	1,118	266,771,798
5	LP-4	1,237	6,032,075.324	39,301.857	747,722		10,747,730		3,651,579	603,252	(2,393,977)	4,327,879	12,941,043	69,927,085	(190,809)	(190,981)	172	69,736,276
6	LP-5	166	12,100,437.660	1,980,048	100,368		8,726,276		62,352		(121,278)	273,821	3,318,584	14,340,111	(59,651)	(39,687)	36	14,300,460
7	BL	42	7,274,464	348,811	1,257		17,400		26,126	2,185	(21,321)	199,974	651,501	1,225,933	(1,366)	(1,378)	12	1,224,567
8	SA		5,349,372	3,354,653			12,792		241,656	1,608	(205,665)	142,790	460,506	4,008,340	(12,916)	(12,916)		3,995,424
9	SM	57	1,262,858	282,195			3,007		20,058	385	(17,244)	8,130	26,619	323,150	(1,053)	(1,053)		322,097
10	SHS	1,130	26,538,996	9,733,287			63,277		688,763	8,094	(594,875)	179,422	580,407	10,658,376	(36,131)	(36,135)	4	10,622,245
11	SE	110	24,967,255	1,822,447			59,966		131,028	7,373	(111,324)	82,304	276,945	2,268,639	(6,918)	(6,931)	13	2,261,720
12	TS	7	289,330	27,909			697		2,019	89	(1,705)	1,190	3,872	34,071	(107)	(107)		33,965
13	SLE	477	15,017,109	9,237,324			35,918		653,451	4,513	(565,078)	106,401	346,647	9,819,176	(34,443)	(34,443)		9,784,733
14	GH-2	1,477	35,291,556	1,306,592	44,272		84,456		102,455	10,599	(79,833)	253,154	824,759	2,546,454	(5,404)	(5,416)	12	2,541,050
15	Rate Revenue	1,563,765	42,775,651,425	\$ 907,890,234	\$ 26,062,195	\$ 143,159,005	\$ 71,647,405	\$ -	\$ 88,972,498	\$ 12,504,805	\$ (61,564,983)	\$ 325,312,939	\$ 915,485,516	\$ 2,429,429,814	\$ (4,707,032)	\$ (4,719,373)	\$ 12,341	\$ 2,424,722,582
16	Annualization Adjustment		569,772,231	\$ 4,932,874										\$	4,932,874			\$ 4,932,874
17	Total PUC Tariff Revenue		43,345,423,656	\$ 912,783,108	\$ 26,062,195	\$ 143,159,005	\$ 71,647,405	\$ -	\$ 88,972,498	\$ 12,504,805	\$ (61,564,983)	\$ 325,312,939	\$ 915,485,516	\$ 2,434,362,488	\$ (4,707,032)	\$ (4,719,373)	\$ 12,341	\$ 2,429,655,456
18	Other Electric Revenues																	
19	Late Payment			\$ 15,305,520										\$ 15,305,520			\$	15,305,520
20	Misc. Revenue			\$ 969,910										\$ 969,910			\$	969,910
21	Rent			\$ 40,830,000								\$ 2,916,000		\$ 43,746,000			\$	43,746,000
22	Other			\$ 3,990,000								\$ 974,520,000		\$ 978,510,000			\$	978,510,000
23	Total Other			\$ 61,095,430	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 977,436,000	\$ -	\$ 1,038,531,430	\$ -	\$ -	\$ -	\$ 1,038,531,430
24	Total Operating Revenue			\$ 973,878,538	\$ 26,062,195	\$ 143,159,005	\$ 71,647,405	\$ -	\$ 88,972,498	\$ 12,504,805	\$	\$ 1,302,748,939	\$ 915,485,516	\$ 3,472,893,918	\$ (4,707,032)	\$ (4,719,373)	\$ 12,341	\$ 3,468,186,886

Note 1: PPL Electric proposes to roll revenues related to SMR-2, CER, DSIC, and TCJA into base distribution rates.

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PPL Electric Utilities Corporation
REBUTTAL 12 month Period Ended June 30, 2027 Proforma Budget at Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
Line Number	Rate Schedule	Budgeted Base Distribution Rate Revenue	Base Distribution Revenue Increase	Smart Meter Rider (SMR)	Universal Service Rider (USR)	Act 129 Compliance Rider (ACR)	Competitive Enhancement Rider (CER)	Distribution System Improvement Charge (DSIC)	Storm Damage Expense Rider (SDER)	Tax Reform (TCJA)	Transmission Service Charge (TSC)	Generation Service Charge (GSC)	Total Proposed Rate Revenue with Increase	State Tax Adjustment Surcharge (STAS) Distribution	State Tax Adjustment Surcharge (STAS) Other	Total Revenue with Proposed Revenue Increase	Total Revenue \$ Change	Total Revenue % Change
1	RS	\$ 632,506,358	\$ 278,580,907	Note 1	\$ 143,159,005	\$ 27,792,556	Note 1	Note 1	Note 1	Note 1	\$ 271,123,180	\$ 754,895,226	\$ 2,108,057,232	\$ -	\$ 10,196	\$ 2,108,067,428	\$ 232,071,061	12.53%
2	RTS																	
3	GS-1	80,069,668	32,195,137			4,491,361					18,548,983	60,430,958	195,736,107	-	790	195,736,897	26,063,966	15.59%
4	GS-3	128,185,677	45,075,360			19,696,425					30,319,865	81,553,309	305,629,636	-	1,116	305,630,754	39,058,956	14.64%
5	LP-4	39,301,657	21,859,623			10,747,730					4,327,879	12,941,043	89,178,132	-	172	89,178,304	19,442,028	27.88%
6	LP-5	1,980,048				8,726,276					273,821	3,318,584	14,298,729	-	36	14,298,765	(1,695)	-0.01%
7	BL	348,811				17,400					199,974	651,501	1,217,686	-	12	1,217,698	(6,869)	-0.56%
8	SA	3,354,653	1,010,269			12,792					142,790	460,506	4,981,009	-		4,981,009	985,586	24.67%
9	SM	282,195	67,378			3,007					8,130	26,619	387,328	-		387,328	65,231	20.25%
10	SHS	9,753,287	2,600,644			63,277					179,422	580,407	13,157,037	-	4	13,157,041	2,534,797	23.86%
11	SE	1,822,447	2,580,310			59,966					82,304	276,845	4,821,872	-	13	4,821,885	2,560,164	113.20%
12	TS	27,909	544,376			697					1,190	3,872	578,045	-		578,045	544,080	1601.89%
13	SLE	9,237,324	8,320			35,918					106,401	346,647	9,734,610	-		9,734,610	(50,123)	-0.51%
14	GH-2																	
15	Rate Revenue	\$ 907,850,234	\$ 384,522,323	\$ -	\$ 143,159,005	\$ 71,647,405	\$ -	\$ -	\$ -	\$ -	\$ 325,312,939	\$ 915,485,516	\$ 2,747,977,422	\$ -	\$ 12,341	\$ 2,747,989,763	\$ 323,267,181	
16	Annualization Adjustment	\$ 4,932,874														\$ 4,932,874		
17	Total PUC Tariff Revenue	\$ 912,783,108	\$ 384,522,323	\$ -	\$ 143,159,005	\$ 71,647,405	\$ -	\$ -	\$ -	\$ -	\$ 325,312,939	\$ 915,485,516	\$ 2,747,977,422	\$ -	\$ 12,341	\$ 2,752,922,637		
Other Electric Revenues																		
18	Late Payment	\$ 15,305,520	\$ 1,699,027										\$ 17,004,547			\$ 17,004,547		
19	Misc. Revenue	\$ 969,910											\$ 969,910			\$ 969,910		
20	Rent	\$ 40,830,000									\$ 2,916,000		\$ 43,746,000			\$ 43,746,000		
21	Other	\$ 3,990,000									\$ 974,520,000		\$ 978,510,000			\$ 978,510,000		
22	Total Other	\$ 61,095,430	\$ 1,699,027	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 977,436,000	\$ -	\$ 1,040,230,457			\$ 1,040,230,457		
23	Total Operating Revenue	\$ 973,878,538	\$ 386,221,350	\$ -	\$ 143,159,005	\$ 71,647,405	\$ -	\$ -	\$ -	\$ -	\$ 1,302,748,939	\$ 915,485,516	\$ 3,788,207,879	\$ -	\$ 12,341	\$ 3,793,153,094		

Note 1: Base distribution revenue increase includes roll-in of SMR, CER, DSIC, and TCJA as shown on D-3 Page 2.
Note 2: This reflects the elimination of the RTS and GH-2 rate schedules.

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustment to Wages and Benefits
Year Ended June 30, 2027
(Thousands of Dollars, except wages per employee)

This adjustment was made to reflect the average number of transmission and distribution-related employees and the level of wages and benefits in effect at the end of the year.

Line No.	Description	REBUTTAL Amount
1	Average monthly T & D-related wages to expense per employee	\$ 5,019
2	T & D-related personnel employed at the end of the year	1,477
3	Annualized T & D-related total wages to expense(line 1 x line 2 x 12 months)	88,964
4	Less: Actual T & D-related wages to expense for the year ended June 30, 2027	<u>89,386</u>
5	Decrease in wages to expense (line 3 - line 4)	(422)
6	Decrease in benefits expense (line 5 x 22.8%)	(96)
7	Decrease in payroll taxes (line 5 x 7.65%)	<u>(32)</u>
8	Total decrease in T&D-related wages, taxes and benefits expenses (line 5 + line 6 + line 7)	<u><u>\$ (550)</u></u>

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustment for Competitive Enhancement Rider Roll-in to Base Rates
12 Months Ended June 30, 2027
(Thousands of Dollars)

This adjustment is made to roll the Competitive Enhancement Rider (CER) costs into base rates. Costs eligible for the CER include the eligible customer list which is updated every 5 years in accordance with Commission Order dated March 13, 2025 at Docket No. M-2010-2183412.

Line		REBUTTAL
<u>No.</u>	<u>Description</u>	<u>Amount</u>
1	Estimated Eligible Customer List Expense	\$ -
2	Normalized amount (line 1 / 5 years)	\$ -
3	Less: Amount per books	\$ -
4	Net increase in distribution operating expense	\$ -

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustment to Annual Depreciation Expense
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.	Depreciation - Electric Plant In Service	REBUTTAL Total
		<u>Amount</u>
1	Intangible Plant	\$ -
2	Transmission Plant	224,744
3	Distribution Plant	263,067
4	General Plant	59,764
6	Total	<u>547,575</u>
7	Less: Depreciation expense per books	468,251
8	Net increase in depreciation expense	<u><u>\$ 79,324</u></u>

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PPL ELECTRIC UTILITIES CORPORATION
REBUTTAL Computation of Income Taxes - Electric
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	Total Amount Per Budget	Less: Automatic Recovery Clauses/Riders	T&D Operations Per Budget	Pro forma Adjustments	T&D Pro forma at Present Rates
1	Operating Revenues	\$ 3,463,885	\$ (1,420,551)	\$ 2,043,334	\$ 4,723	\$ 2,048,057
	Operating Expenses					
2	Operation and maintenance	1,777,588	(1,276,262)	501,327	(952)	500,375
3	Depreciation and amortization	468,251	0	468,251	81,150	549,401
4	Regulatory Debits and Credits	11,007	(11,007)	0	3,990	3,990
5	Taxes Other than Income	159,956	(90,524)	69,432	(372)	69,060
6	Income Taxes	24,304	(8,329)	15,975	355	16,330
7	Income Taxes - State	448	(3,096)	(2,648)	(343)	(2,991)
8	Deferred Income Taxes	146,164	0	146,164	(9,629)	136,535
9	Investment Tax Credit - Amortization	(31)	0	(31)	0	(31)
10	Gains and Losses on Property Dispositions		0	0	0	0
11	Total Operating Expense	<u>2,587,687</u>	<u>(1,389,217)</u>	<u>1,198,470</u>	<u>74,199</u>	<u>1,272,669</u>
12	Operating Income	876,198	(31,334)	844,864	(69,476)	775,388
13	Less: Interest Expense	306,018	0	306,018	(13,650)	292,368
14	Net Operating Income	<u>570,180</u>	<u>(31,334)</u>	<u>538,846</u>	<u>(55,826)</u>	<u>483,020</u>
15	Income Tax Adjustments					
16	Federal Income Tax	24,304	(8,329)	15,975	355	16,330
17	State Income Tax	448	(3,096)	(2,648)	(343)	(2,991)
18	Deferred Income Taxes	146,164	0	146,164	(9,629)	136,535
19	Investment tax credit amortization	(31)	0	(31)	0	(31)
	Permanent Items:					
20	Bad Debt Expense Net of Write-offs	500	0	500	0	500
21	ESOP dividend paid in cash	(2,100)	0	(2,100)	0	(2,100)
22	Nondeductible Officers Compensation	5,550	0	5,550	0	5,550
23	Nondeductible Subsidized Expenses	1,500	0	1,500	0	1,500
	Plant Temporary Items:					
24	Book Depreciation	468,251	0	468,251	79,324	547,575
25	Book Depreciation Capitalized	5,160	0	5,160	(5,160)	0
26	Contributions in aid of construction	40,198	0	40,198	0	40,198
27	Plant Basis Adjustments - Tax Repairs and Other	(196,193)	0	(196,193)	(49,920)	(246,113)
28	Plant Basis Adjustments - Capitalized R&D	38,106	0	38,106	0	38,106
29	Removal costs	(105,534)	0	(105,534)	24,722	(80,812)
30	Tax Depreciation	(878,180)	0	(878,180)	24,161	(854,019)
31	Tax Gains/(Losses) on Plant Dispositions	5,026	0	5,026	0	5,026
	Non-Plant Temporary Items:					
32	Bad Debt Expense Net of Write-offs	(314)	0	(314)	0	(314)
33	Deferred Compensation - Officers	390	0	390	0	390
34	Environmental Clean-up	160	0	160	0	160
35	Pension and supplemental retirements	(13,763)	0	(13,763)	0	(13,763)
36	Post-employment benefits	(330)	0	(330)	0	(330)
37	Post-retirement benefits	2,388	0	2,388	0	2,388
38	Post-retirement - VEBA	(1,384)	0	(1,384)	0	(1,384)
39	Prepays	(882)	0	(882)	0	(882)
40	Reacquired debt costs	450	0	450	0	450
41	Regulatory Asset - Competitive Enhancement Rider (CER)	0	0	0	0	0
42	Regulatory Asset - IJJA Expense Deferral Adjustment	0	0	0	211	211
43	Regulatory Asset - Rate Cases Expenses	48	0	48	693	741
44	Regulatory Asset - Storm Deferral	11,022	0	11,022	(7,243)	3,779
45	Service Company Costs	1,426	0	1,426	0	1,426
46	Vacation Pay	290	0	290	0	290
47	Income Tax Adjustments	<u>(447,330)</u>	<u>(11,425)</u>	<u>(458,755)</u>	<u>57,171</u>	<u>(401,584)</u>
48	Taxable Net Income Before Special Deductions	<u>\$ 122,850</u>	<u>\$ (42,759)</u>	<u>\$ 80,091</u>	<u>\$ 1,345</u>	<u>\$ 81,436</u>

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PPL ELECTRIC UTILITIES CORPORATION
REBUTTAL Computation of Income Taxes - Electric
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	Total Amount Per Budget	Less: Automatic Recovery Clauses/Riders	T&D Operations Per Budget	Pro forma Adjustments	T&D Pro forma at Present Rates
<u>PA Corporate Net Income Tax Calculation</u>						
1	Taxable Net Income Before Special Deductions	\$ 122,850	\$ (42,759)	\$ 80,091	\$ 1,345	\$ 81,436
PA Special Deductions						
2	Dividends Paid Credit		0	0	0	0
3	Bonus Depreciation Adjustment	(118,599)	0	(118,599)	(6,076)	(124,675)
4	State Adjustment	0	0	0	0	0
5	PA Taxable Income / (Loss) before NOL CF/(Utilization)	4,251	(42,759)	(38,508)	(4,731)	(43,239)
6	PA NOL Carryforward/(Utilization)	0	0	0	0	0
7	PA Taxable Income / (Loss) after NOL CF/(Utilization)	4,251	(42,759)	(38,508)	(4,731)	(43,239)
8	PA Tax @ 7.49% for Jul-Dec 2026 and 6.99% for Jan-Jun 2027	448	(3,096)	(2,648)	(343)	(2,991)
9	PA Tax Credits	0	0	0	0	0
10	Accrual for Potential Deficiency	0	0	0	0	0
11	State Income Tax Settlements	0	0	0	0	0
12	Prior Period Tax Return Adjustments	0	0	0	0	0
13	Total PA Income Tax	<u>\$ 448</u>	<u>\$ (3,096)</u>	<u>\$ (2,648)</u>	<u>\$ (343)</u>	<u>\$ (2,991)</u>
<u>Federal Income Tax Calculation</u>						
14	Taxable Net Income Before Special Deductions	\$ 122,850	\$ (42,759)	\$ 80,091	\$ 1,345	\$ 81,436
Federal Special Deductions						
15	PA Income Tax Less Tax Credits	(448)	3,096	2,648	343	2,991
16	Dividends Paid Credit	0	0	0	0	0
17	State Income Tax Settlements	0	0	0	0	0
18	State Income Tax Adjustment for Prior Year	0	0	0	0	0
19	Federal Taxable Income	122,402	(39,663)	82,739	1,688	84,427
20	Federal NOL Carryforward/(Utilization)	0	0	0	0	0
21	Federal Taxable Income after NOL CF/(Utilization)	122,402	(39,663)	82,739	1,688	84,427
22	Federal Tax @ 21%	25,704	(8,329)	17,375	355	17,730
23	Federal Tax Credits	(1,400)	0	(1,400)	0	(1,400)
24	Accrual for Potential Deficiency	0	0	0	0	0
25	Prior Period Tax Return Adjustments	0	0	0	0	0
26	Total Federal Income Tax	<u>\$ 24,304</u>	<u>\$ (8,329)</u>	<u>\$ 15,975</u>	<u>\$ 355</u>	<u>\$ 16,330</u>

PPL ELECTRIC UTILITIES CORPORATION
REBUTTAL Adjustment to Interest Deduction for Income Tax Purposes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

This adjustment provides for the annualized interest on claimed measures of value at June 30, 2027.

Line No.	Description	REBUTTAL Amount
1	Measures of value at June 30, 2027 (C-1 SUPPLEMENTAL)	\$ 13,110,664
2	Long-term debt ratio (B-8)	43.95%
3	Embedded cost of long-term debt (B-8)	5.08%
4	Annualized interest (line 1 x line 2 x line 3)	<u>292,368</u>
	Less: Interest expense on T&D operations	
5	(D-17 SUPPLEMENTAL, page 1, line 13, column 3)	<u>306,018</u>
6	Net decrease in interest deduction (line 4 - line 5)	<u><u>\$ (13,650)</u></u>

PPL ELECTRIC UTILITIES CORPORATION
REBUTTAL Operating Revenue and Applicable Tax
Related to Proposed Rate Increase
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	REBUTTAL Amount
1	Additional rate revenue from proposed rate increase	\$ 384,522
	Plus:	
2	Provision for late payment fee adjustment (line 1 x .44186%)	1,699
3	Total Revenue (line 1 plus line 2)	<u>386,221</u>
	Less:	
4	Provision for uncollectible accounts expense (line 1 x 1.67%)	6,422
5	PA gross receipts tax (line 3 - line 4) x 59 mills	22,408
6	Provision for PUC Assessment expense (line 3 x .28757%)	1,111
7	Taxable income for PA Corporate net income tax (line 1 plus line 2 less lines 3, 4 and 5)	<u>356,281</u>
8	PA corporate net income tax (line 7 x 7.24%) = (7.49% x 50% + 6.99% x 50%)	<u>25,795</u>
9	Taxable income for Federal income tax	330,486
10	Federal income tax (line 9 x 21%)	<u>69,402</u>
11	Operating income	<u>\$ 261,084</u>

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustment to Deferred Income Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

Line No.	Provision	Debit	Credit	Net Deferred Tax Amount per Budget	Adjustments	T&D Operations per Budget	T&D Pro forma at Present Rates	Net increase / (decrease) in deferred income taxes
Distribution Property:								
1	Method and Life Book/Tax Plant Differences	\$ 34,501	\$ -	\$ 34,501	\$ 0	\$ 34,501	\$ (4,938)	\$ (39,439)
2	Contributions In Aid of Construction (CIAC)	0	(7,435)	(7,435)	0	(7,435)	(6,949)	486
3	Other Plant Basis Adjustments	26,220	0	26,220	0	26,220	37,579	11,359
4	Federal NOL Carryforward	0	0	0	0	0	0	0
5	State NOL Carryforward	0	0	0	0	0	0	0
6	Deficient Federal NOL Deferred Taxes	476	0	476	0	476	476	0
7	Non-Plant Deferred Taxes	4,489	(4,184)	305	0	305	0	(305)
8	Total Distribution Property	<u>65,686</u>	<u>(11,619)</u>	<u>54,067</u>	<u>0</u>	<u>54,067</u>	<u>26,168</u>	<u>(27,899)</u>
General Property:								
9	Method and Life Book/Tax Plant Differences	0	(5,315)	(5,315)	0	(5,315)	18,002	23,317
10	Contributions In Aid of Construction (CIAC)	56	0	56	0	56	61	5
11	Other Plant Basis Adjustments	1,714	0	1,714	0	1,714	2,318	604
12	Non-Plant Deferred Taxes	0	0	0	0	0	0	0
13	Total General Property	<u>1,770</u>	<u>(5,315)</u>	<u>(3,545)</u>	<u>0</u>	<u>(3,545)</u>	<u>20,381</u>	<u>23,926</u>
Transmission Property:								
14	Contributions In Aid of Construction (CIAC)	553	0	553	0	553	842	289
15	Net Book/Net Tax Plant (Excluding CIAC)	95,044	0	95,044	0	95,044	88,930	(6,114)
16	Federal NOL Carryforward	0	0	0	0	0	0	0
17	State NOL Carryforward	0	0	0	0	0	0	0
18	Federal Deficient NOL Deferred Taxes	214	0	214	0	214	214	0
19	Non-Plant Deferred Taxes	47	(216)	(169)	0	(169)	0	169
20	Total Transmission Property	<u>95,858</u>	<u>(216)</u>	<u>95,642</u>	<u>0</u>	<u>95,642</u>	<u>89,986</u>	<u>(5,656)</u>
Total								
21	Method and Life Book/Tax Plant Differences	34,501	(5,315)	29,186	0	29,186	13,064	(16,122)
22	Contributions In Aid of Construction (CIAC)	609	(7,435)	(6,826)	0	(6,826)	(6,046)	780
23	Other Plant Basis Adjustments	27,934	0	27,934	0	27,934	39,897	11,963
24	Net Book/Net Tax Plant (Excluding CIAC)-Transmission	95,044	0	95,044	0	95,044	88,930	(6,114)
25	Federal NOL Carryforward	0	0	0	0	0	0	0
26	State NOL Carryforward	0	0	0	0	0	0	0
27	Federal Deficient NOL Deferred Taxes	690	0	690	0	690	690	0
28	Non-Plant Deferred Taxes	4,536	(4,400)	136	0	136	0	(136)
29	Total	<u>\$ 163,314</u>	<u>\$ (17,150)</u>	<u>\$ 146,164</u>	<u>\$ -</u>	<u>\$ 146,164</u>	<u>\$ 136,535</u>	<u>\$ (9,629)</u>
30	Deferred Taxes per Schedule D-17 SUPPLEMENTAL			<u>D-17, Col 1</u> 146,164	<u>D-17, Col 2</u> 0	<u>D-17, Col 3</u> 146,164	<u>D-17, Col 5</u> 136,535	<u>D-17, Col 4</u> (9,629)

PPL ELECTRIC UTILITIES CORPORATION

REBUTTAL Adjustment to Provision For Deferred Income Taxes
Twelve Months Ended June 30, 2027
(Thousands of Dollars)

This adjustment provides for the annual provision for deferred income taxes due to the (1) Accelerated Cost Recovery System (ACRS) of the Economic Recovery Act of 1981, (2) Modified Accelerated Cost Recovery System (MACRS) of the Tax Reform Act of 1986 and (3) Plant Basis Adjustments

Line

		<u>Per T&D</u> <u>Proforma</u> <u>Sch D-17</u> <u>SUPPLEMENTAL</u> <u>Col 5</u>
<u>No.</u>	<u>Description</u>	
Distribution Property		
1	(Excess)/Deficient Tax over Book depreciation on ACRS and MACRS property	\$ (8,641)
2	Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	(187,658)
3	Reversal of Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	<u>60,312</u>
4	Plant activity for the calculation of deferred income taxes	<u>(135,987)</u>
General Property		
5	Excess Tax over Book depreciation on ACRS and MACRS property	(88,415)
6	Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	0
7	Reversal of Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	<u>(6,579)</u>
8	Plant activity for the calculation of deferred income taxes	<u>(94,994)</u>
Transmission Property		
9	Excess Tax over Book depreciation on ACRS and MACRS property	(289,328)
10	Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	(60,963)
11	Reversal of Plant Basis Adjustments - (Reduction)/Addition to Taxable Income	<u>31,233</u>
12	Plant activity for the calculation of deferred income taxes	<u>(319,058)</u>
13	Total plant activity for the calculation of deferred income taxes	<u>\$ (550,039)</u>
14	Tax Rate Provisions for Distribution and General Property - 21% Reversals for Distribution and General Property - Average Rate Assumption Method (ARAM) Provisions for Transmission Property - 26.9171% (2026) & 26.5221% (2027) Reversals for Transmission Property - ARAM Provisions for Plant Basis Adjustments - 26.9171% (2026) & 26.5221% (2027) Reversals for Plant Basis Adjustments - ARAM	
15	Net annual deferred tax debit / (credit) (Sch D-18, Page 1, line 29, column f)	\$ 136,535
Less: Net provision on T&D operations per budget		
16	Provision for deferred taxes - debit	
17	Provision for deferred taxes - credit	
18	Sub-Total (Sch D-18, Page 1, line 29, column c)	146,164
Less: Net deferred tax debit / (credit) on Automatic Recovery Riders		
19	Sch D-18, Page 1, line 29, column d	0
20	Net increase in deferred income tax provision (line 15 less lines 18 and 19)	<u>\$ (9,629)</u>

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
CHARLES R. SCHRAM
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: Sales Forecast

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Charles R. Schram, and my business address is 2701 Eastpoint Parkway,
4 Louisville, Kentucky 40223.

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

7 A. I am Vice President, Energy Supply and Analysis for LG&E and KU Services Company,
8 which provides services to PPL Electric Utilities Corporation (“PPL Electric” or the
9 “Company”); The Narragansett Electric Company d/b/a Rhode Island Energy (“RIE”) in
10 Rhode Island; Louisville Gas and Electric Company (“LG&E”) and Kentucky Utilities
11 Company (“KU”) in Kentucky; and Old Dominion Power (“ODP”) in Virginia. In this
12 position, among other responsibilities, I oversee the preparation of the forecasts of electric
13 sales, customers, and demands for the Company, RIE, LG&E, KU, and ODP, as well as the
14 forecasts of gas sales, customers, and demands for RIE and LG&E.

16 **Q. Have you previously filed testimony in this matter?**

17 A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric
18 Statement No. 4.

20 **Q. What is the purpose of your rebuttal testimony?**

21 A. The purpose of my rebuttal testimony is to respond to adjustments and recommendations
22 regarding the Company’s Sales Forecasts and Load Forecasts. These adjustments and

1 recommendations were recommended by Energy Justice Advocates (“EJA”) Witness Karl
2 Rábago and Sustainable Energy Fund (“SEF”) Witness John M. Costlow. Specifically, I
3 address EJA’s claim regarding PPL Electric’s residential sales growth relative to the national
4 average and SEF’s assertions on the reasonableness of weather assumptions in the sales
5 forecast. In response, I explain why PPL Electric’s forecasts are reasonable and well-
6 supported and should be adopted by the Commission.

7
8 **Q. Please summarize the key issues and recommendations offered by the opposing**
9 **witnesses that you address in your rebuttal testimony.**

10 A. My commentary on both witnesses’ testimonies primarily focuses on the influence of
11 temperature on sales and how that impact can vary significantly from year to year.

12
13 **Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?**

14 A. No.

15
16 **Q. How is the remainder of your rebuttal testimony organized?**

17 A. Section II discusses intervenor testimony associated with the sales forecast, and Section III is
18 the conclusion.

1 **II. SALES FORECAST**

2 **Q. How does EJA Witness Rábago summarize the Company's Sales Forecasts?**

3 A. According to Mr. Rábago, PPL Electric's allegation that it has experienced and is expected to
4 continue to experience "little or no growth" in sales for residential differs from the situation
5 presented in the Edison Electric Institute ("EEI") report on total electricity sales. The EEI
6 report states that in 2024 "total electricity sales to residential customers in the U.S. increased
7 2.7% after falling 3.6% in 2023." (EJA St. No. 1, p. 13.) However, Mr. Rábago does not
8 make a recommendation as to any adjustments to the Company's sales forecast.

9
10 **Q. Do you have any comments on Mr. Rábago's observation?**

11 A. Yes. Mr. Rábago did not acknowledge that PPL Electric's sales growth rates quoted in his
12 testimony at page 14, lines 1-21 assume normal weather, while the EEI report is referring to
13 actual sales and not weather-normalized sales. (EJA St. No. 1, p. 14.) This fundamental
14 difference renders his comparison misleading. PPL Electric's experience of relatively flat
15 usage per customer is not unique to its service territory, given reductions to usage from
16 distributed generation and increasing levels of energy efficiency across the U.S.

17 Regarding the EEI report, residential sales are weather-sensitive, so the changes in
18 actual sales from one year to the next will primarily be related to differences in weather. PPL
19 Electric's residential load growth in 2023 and 2024 has been similar to the EEI total residential
20 load growth figures that Mr. Rábago references, but growth rates can and do vary across
21 utilities across the country. For PPL Electric, actual revenue period residential sales increased

1 1.4% in 2024 after falling 5% in 2023. Actual calendar period residential sales increased 3.7%
2 in 2024 after falling 8.3% in 2023. These year-to-year variances are clearly weather-related.
3

4 **Q. Does SEF Witness Costlow also make any observations regarding the Company's Load**
5 **Forecast?**

6 A. Yes. According to Mr. Costlow, the Company's proposed decrease in Heating Degree Days
7 ("HDD") is not reasonable for the Fully Projected Future Test Year ("FPFTY") because the
8 2024 Pennsylvania Climate Impacts Assessment indicates that the average annual daily
9 temperature will decrease by 13.8% by 2050. (SEF St. No. 1, p. 9.) He also states that summer
10 peaks will become more pronounced, and Cooling Degree Days ("CDD") will increase,
11 resulting in an increase in electric consumption for cooling. (*Id.*) Based on that same 2024
12 Pennsylvania Climate Impacts Assessment, he asserts that nighttime temperatures are
13 forecasted to be higher, rising from 4 days to 26 days by mid-century above 68 degrees. (*Id.*)
14 Therefore, he disagrees with the Company's sales forecast. (*Id.*)
15

16 **Q. What is Mr. Costlow's recommendation?**

17 A. He recommends that the FPFTY "be set to a static sales forecast utilizing the historic test year
18 consumption," due to the "lack of credible evidence that sales will decrease at the rate PPL
19 Electric has forecast." (SEF St. No. 1, p. 10.)
20

1 **Q. Should Mr. Costlow’s recommendation be adopted?**

2 A. No. As noted above in my response to Mr. Rábago, temperatures can vary significantly from
3 year to year. For this reason, relying on a single year as the basis for a “normal” weather
4 assumption in a load forecast is unreasonable. It is not standard industry practice to define
5 normal weather using only one year because of the inherent volatility in annual weather
6 patterns. My direct testimony explains the rationale for using a 20-year normal weather
7 assumption in the sales forecast. (See PPL Electric St. No. 4, p. 9.) To be clear, the 20-year
8 normal is a forecast assumption that is commonly used by utilities in load forecasting. The
9 Company, therefore, does not attempt to predict future weather conditions, contrary to Mr.
10 Costlow’s assertions; rather, the monthly HDD and CDD assumptions are simply the product
11 of this standard methodology.

12 As I also explained in my direct testimony, temperatures during the Historic Test Year
13 (“HTY”) were favorable for sales compared to normal conditions. (See PPL Electric St. No.
14 4, pp. 5-9.) Therefore, a forecast based on normal weather assumptions will, all else equal, be
15 lower than the HTY. In contrast, calendar year 2023 experienced temperatures unfavorable
16 for sales relative to normal, while 2022 was slightly favorable. This explains the 8.3%
17 decrease in residential sales compared to calendar year 2022, which was also noted above in
18 response to Mr. Rábago. While 2023 sales were suppressed, by the same logic, using only
19 2023 weather as the basis for the forecast would also be unreasonable.

20

1 **Q. Do you agree with Mr. Costlow’s characterization of the 2024 PA Climate Impacts**
2 **Assessment report?**

3 A. No. It appears Mr. Costlow misquotes the report. While the report primarily addresses years
4 well beyond the FPFTY and uses a dated historical baseline for comparison in many instances,
5 it clearly states on page 13 that “[h]eating degree days will also decrease.”¹ It also states on
6 page 18 that “[a]nnual total heating degree days are anticipated to decrease by 13% by mid-
7 century . . . compared to the historical baseline.”² However, Mr. Costlow asserts that the report
8 states that *temperatures* will decrease by 2050, which is not consistent with what the report
9 states on pages 13 and 18.³ Again, it is also worth noting that 2050 is well beyond the FPFTY
10 under consideration in this case. The report goes on to say that its historical baseline is 1971-
11 2000, a period that ended 25 years ago.⁴ None of that baseline period is included in the
12 Company’s normal weather assumptions. Therefore, quoting percentage changes versus a
13 baseline period ranging from 25 to 55 years ago is irrelevant to assessing the reasonableness
14 of the Company’s forecast.

15
16 **Q. Does the weather data support your position that temperatures can be volatile from year**
17 **to year?**

18 A. Yes, it does. Mr. Costlow states in his testimony that the changes from actual January and
19 February HDDs to the normal forecast assumption for HDDs in those respective months are

¹ Pennsylvania Climate Impacts Assessment 2024, Pennsylvania Department of Environmental Protection, p. 13 (April 2025).

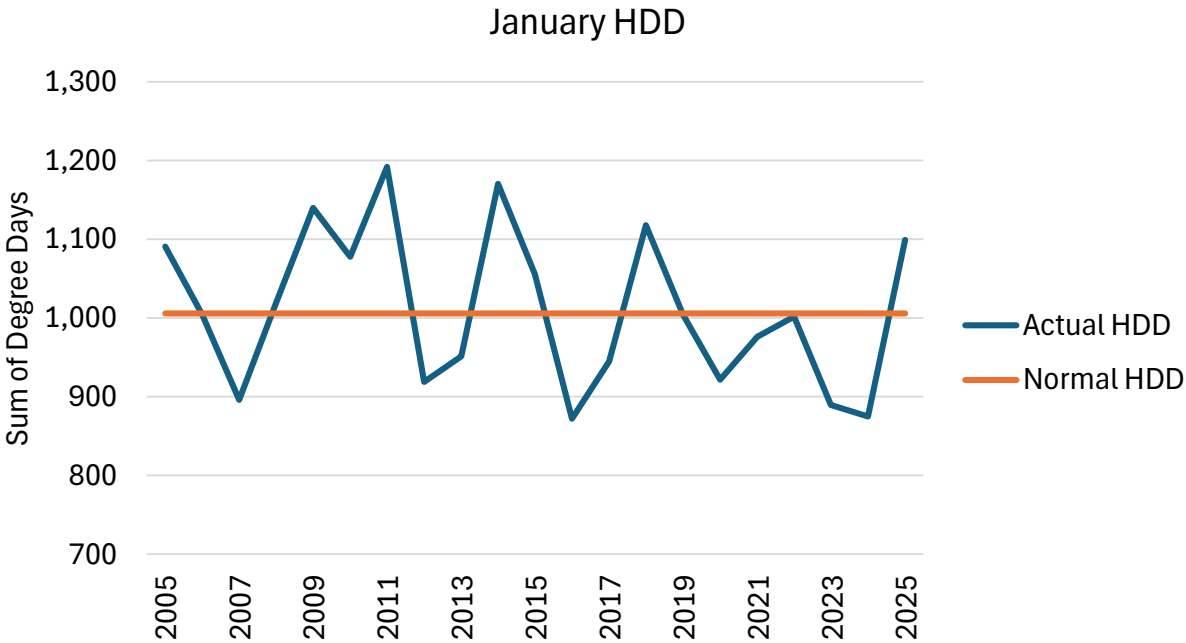
² *Id.* at 18.

³ Decreasing temperatures would result in an increase in HDD and decrease in CDD.

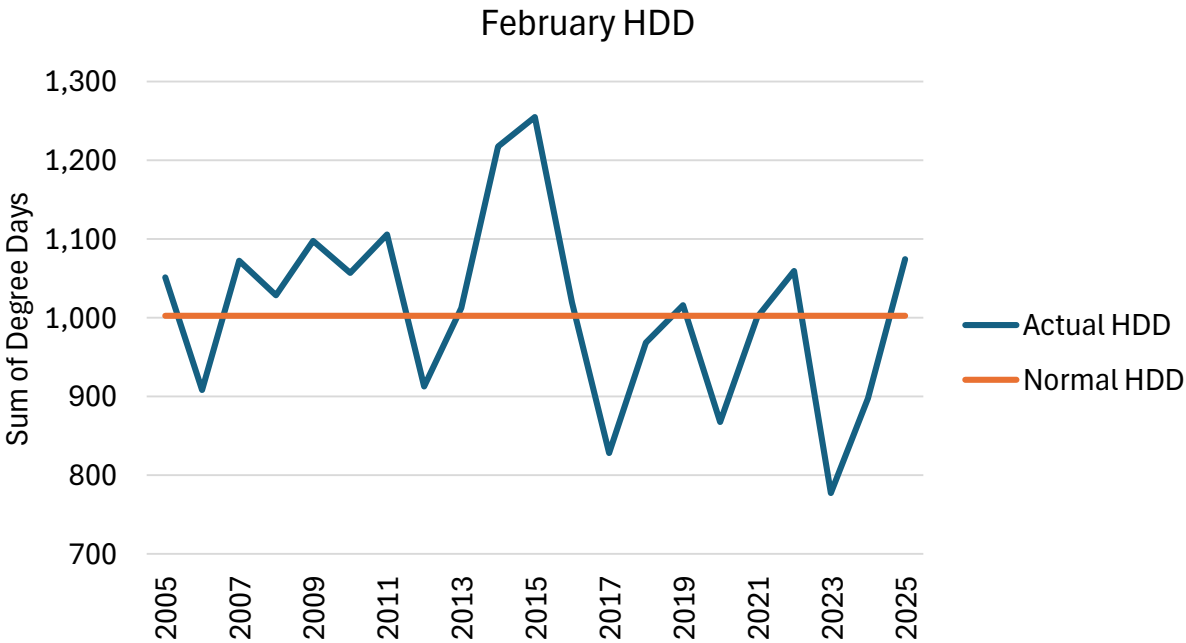
⁴ Pennsylvania Climate Impacts Assessment 2024, Pennsylvania Department of Environmental Protection, p. 2 (April 2025).

1 unreasonable. (SEF St. No. 1, pp. 8-9.) Figures 1 and 2 below illustrate January and February
2 revenue period HDD by year, with the 20-year normal assumptions shown as horizontal lines.
3 Figure 1 illustrates that January 2025, which falls within the HTY, was the first above-normal
4 HDD January since 2018. Figure 2 illustrates that February 2025, also within the HTY, is 1
5 of only 3 above-normal HDD Februarys since 2016. Figures 1 and 2 together demonstrate the
6 significant volatility that can occur from one year to the next. For instance, the difference
7 between January 2024 (roughly 13% below normal HDD) and January 2025 (over 9% above
8 normal HDD) is nearly 225 HDD. The difference between February 2023 (nearly 11% below
9 normal HDD) and February 2025 (nearly 7% above normal HDD) is 297 HDD. The historical
10 data for both months supports the Company's position that choosing a single-weather-year
11 for forecasting electricity sales is unreasonable.

1 **Figure 1. January Revenue Period HDD by Year (2005-2025)**



4 **Figure 2. February Revenue Period HDD by Year (2005-2025)**



1 **III. CONCLUSION**

2 **Q. Please summarize your rebuttal testimony.**

3 A. In summary:

- 4 • Temperatures can vary significantly from year to year, so trends cannot be
5 discerned from a simple year-to-year comparison; therefore, a one-year normal
6 assumption for purposes of sales forecasting is not reasonable;
- 7 • The Company's 20-year normal assumption is reasonable, as discussed in my direct
8 testimony;
- 9 • The Company is not attempting to predict future weather in this process;
- 10 • Mr. Costlow misquotes the 2024 PA Climate Impacts Assessment;
- 11 • Weather in 2050 is not relevant to the FPFTY; and
- 12 • When citing percentage changes in HDDs or CDDs, using a relevant point of
13 reference for comparison is important.

14 For the reasons cited above, the Commission should reject the proposed adjustments and
15 adopt PPL Electric's forecast as reasonable and consistent with industry standards.

16

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

18 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
DANIEL S. DANE
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Late Payment Revenues**
 O&M Expense Adjustments
 Revenue Requirement
 Taxes Other than Income Taxes
 Interest Synchronization

Dated: January 23, 2026

I. INTRODUCTION

Q. Mr. Dane, please state your full name and business address.

A. My name is Daniel S. Dane. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

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

A. I am the President of Concentric Energy Advisors, Inc. ("Concentric").

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of PPL Electric Utilities Corporation ("PPL Electric" or the "Company"), which is pre-marked as PPL Electric Statement No. 6.

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to certain portions of the direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"), the Office of Consumer Advocate ("OCA"), and the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"). Specifically, I will respond to revenue requirements issues raised by those parties related to:

- Late payment revenues;
- Operation and maintenance expense adjustments;
- Taxes other than income taxes; and

- Interest synchronization.

Q. Do you have any initial comments on I&E's and OCA's proposals?

A. Yes. While the Company disagrees with many of the adjustments proposed by I&E and OCA to reduce the revenue requirement for the fully projected future test year ("FPFTY"), as discussed herein there are certain areas where the Company has adopted the adjustments proposed by those parties to limit the scope of the areas of disagreement.

Q. Are you sponsoring any additional exhibits?

A. Yes. I am sponsoring the following exhibits:

- PPL Electric DSD-1R Rebuttal Exhibit D-1
- PPL Electric DSD-2R OCA Revenue Requirement Reflecting Discovery Updates
- PPL Electric DSD-3R I&E Revenue Requirement Reflecting Discovery Updates

In addition, I am sponsoring or co-sponsoring Schedules D-5, D-8, D-15, D-17, and D-18 of PPL Electric Rebuttal Exhibit No. 1.

Q. Please summarize I&E's adjustments to operating income.

A. I&E Witnesses Ethan Cline, Zachari Walker and Christopher Keller recommend adjustments to late payment revenues and several categories of operating expenses. The table below provides the Company's FPFTY amount (as updated in discovery), the I&E recommended amount, and I&E's proposed adjustment related to late payment revenues.

Operating Revenues	FPFTY As Updated in Discovery	Proposed Adjustment	I&E Recommendation
Late Payments	\$ 15,305,520	\$ 1,278,916	\$ 16,584,436

1
2 For operating expenses for which I&E proposes adjustments, the table below provides the
3 Company's FPFTY amount (as updated in discovery), the I&E recommended amount, and
4 I&E's proposed adjustment.

<u>O&M, Regulatory Amortizations and Taxes Other Than Income Taxes</u>	<u>FPFTY As Updated in Discovery</u>	<u>Proposed Adjustment</u>	<u>I&E Recommendation</u>
Advertising Expenses	\$ 923,000	\$ (130,000)	\$ 793,000
Bank Charges	\$ 900,000	\$ (388,000)	\$ 512,000
Company Sponsorships	\$ 28,000	\$ (28,000)	\$ -
Economic Development Proposal	\$ 400,000	\$ (400,000)	\$ -
Incentive Compensation	\$ 4,412,000	\$ (2,050,000)	\$ 2,362,000
Infrastructure Investment and Jobs Amortization	\$ 211,000	\$ (211,000)	\$ -
Membership Dues and Subscriptions	\$ 2,800,000	\$ (2,800,000)	\$ -
Payment Transaction Fees ¹	\$ 5,200,000	\$ (1,200,000)	\$ 4,000,000
Payroll and Benefits	\$ 81,900,000	\$ (5,421,000)	\$ 76,479,000
Payroll Taxes	\$ 6,961,000	\$ (2,368,000)	\$ 4,593,000
Rate Case Expense	\$ 741,000	\$ (304,000)	\$ 437,000
Storm Damage Expense	\$ 42,500,000	\$ (9,994,000)	\$ 32,506,000
Vegetation Management	\$ 49,999,000	\$ (15,579,000)	\$ 34,420,000
Total Proposed Adjustments to O&M, Regulatory Amortizations, and Taxes Other Than Income Taxes		\$ (40,873,000)	

5

¹ As stated in OCA XXV-18 and clarified in PPL Electric Witness Lisa Norden's rebuttal testimony (PPL Electric St. No. 18-R), payment transaction fees included in the FPFTY are \$5,200,000. As Ms. Norden explains, historical payment transaction fees were \$4,000,000 and are projected to increase by 30%. An allowance of only the historical amount of payment transaction fees, as proposed by I&E, would result in a \$1,200,000 reduction in O&M expenses

Q. Please summarize OCA’s adjustments to operating income.

A. OCA Witnesses Lafayette K. Morgan Jr., David J. Garrett, and Grace N. Koenig also recommend adjustments to several categories of operating expenses. For those categories of operating expenses, the table below provides the Company’s FPFTY amount (as updated in discovery), the OCA recommended amount, and OCA’s proposed adjustment.

<u>O&M, Regulatory Amortizations and Taxes Other Than Income Taxes</u>	<u>FPFTY As Updated in Discovery</u>	<u>Proposed Adjustment</u>	<u>OCA Recommendation</u>
Advertising Expenses	\$ 923,000	\$ (130,000)	\$ 793,000
Company Sponsorships	\$ 28,000	\$ (120,000) ²	\$ (92,000)
Competitive Enhancement Rider / ECL costs	\$ 100,000	\$ (100,000)	\$ -
Economic Development Proposal	\$ 400,000	\$ (400,000)	\$ -
Engineering and Construction Allocation	\$ 22,666,000	\$ (88,000)	\$ 22,578,000
Incentive Compensation	\$ 4,412,000	\$ (955,000)	\$ 3,457,000
Infrastructure Investment and Jobs Amortization	\$ 211,000	\$ (211,000)	\$ -
Membership Dues and Subscriptions	\$ 2,800,000	\$ (808,000)	\$ 1,992,000
Payment Transaction Fees ³	\$ 5,200,000	\$ (600,000)	\$ 4,600,000
Payroll and Benefits	\$ 81,900,000	\$ (696,000)	\$ 81,204,000
Payroll Taxes	\$ 6,961,000	\$ (51,001)	\$ 6,910,000
PURTA	\$ 1,410,000	\$ (1,410,000)	\$ -
Rate Case Expense	\$ 741,000	\$ (297,000)	\$ 444,000
Research and Development	\$ 675,000	\$ (321,000)	\$ 354,000
Universal Services Rider Salaries	\$ (1,400,000)	\$ 1,400,000	\$ -
Total Proposed Adjustments to O&M, Regulatory Amortizations, and Taxes Other Than Income Taxes		\$ (4,787,000)	

² When calculating its proposed adjustment, OCA erroneously used the Company Scholarship value for the Historic Test Year (“HTY”) rather than the FPFTY amount. Because only \$28,000 was included in the FPFTY, OCA’s proposed adjustment would result in a negative expense of \$92,000.

³ As stated in OCA XXV-18 and clarified in PPL Electric Witness Lisa Norden’s rebuttal testimony (PPL Electric St. No. 18-R), payment transaction fees included in the FPFTY are \$5,200,000. As Ms. Norden explains, historical payment transaction fees were \$4,000,000 and are projected to increase by 30%. An allowance of only a 15% increase in payment transaction fees, as proposed by OCA, would result in a \$600,000 reduction in O&M expenses.

II. OTHER OPERATING REVENUES – LATE PAYMENTS

Q. What is I&E Witness Ethan Cline’s recommendation regarding late payment revenue?

A. Mr. Cline recommends that PPL Electric revise its late payment revenue to reflect an anticipated increase due to higher projected revenue levels. (I&E St. No. 4, p. 3.)

Q. How did Mr. Cline determine his proposed increase for late payment revenue under proposed rates?

A. Mr. Cline calculated an increase to late payment revenues by dividing FPFTY late payment revenues into FPFTY total operating revenues at current rates to determine a late payment revenue factor and then multiplied that factor by total operating revenues at proposed rates. Specifically, Mr. Cline estimated a 0.4407% late payment revenue factor by dividing FPFTY late payment revenue of \$15,305,520 by total operating revenues of \$3,472,893,918. He then multiplied that factor by total operating revenues at proposed rates to calculate an adjusted late payment revenue amount of \$16,584,436, which is an increase of \$1,278,916 over the amount proposed by the Company.

Q. Do you agree with Mr. Cline’s assessment of late payment revenue?

A. I agree that an adjustment is appropriate, but I disagree with the calculation of Mr. Cline’s proposed adjustment. That is because I disagree with the total operating revenues at current rates applied in the denominator of Mr. Cline’s factor calculation. Specifically, while I agree that PPL Electric included \$15,305,520 of late payment revenue in the FPFTY (i.e.,

1 the numerator in the calculation), total operating revenue for the FPFTY on Schedule D-1,
2 as updated for rebuttal, is \$3,463,884,656 (i.e., the appropriate updated denominator in the
3 calculation). Dividing \$15,305,520 into \$3,463,884,656 results in an estimated late
4 payment revenue factor of 0.4419% to estimate an increase to late payment revenues.

5
6 **Q. How should late payment revenues be determined in this proceeding?**

7 A. An increase in late payment revenue should be calculated as part of the revenue conversion
8 factor when determining the revenue requirement. The revenue conversion factor is a
9 multiplier used to convert the utility's return on equity into the amount of revenue the utility
10 must collect from customers to realize that return. The increase in late payment revenue
11 should be included in this calculation, similar to increases in uncollectible accounts and
12 taxes.

13
14 **Q. Has the revenue conversion factor been updated in this proceeding?**

15 A. Yes. As shown on PPL Electric Exhibit DSD-1R (Line 1b, column 7), the Company
16 updated the multiplier and applied it to the revenue requirement calculation that includes
17 the adjustments proposed in both discovery and in rebuttal. Including adjustments agreed
18 to herein, the Company calculated \$1,699,050 of additional late payment revenue, which
19 will decrease the proposed increase in base rates. The calculation of late payment revenue
20 should be updated automatically with every revenue requirement update in the case.

1 **III. OPERATION AND MAINTENANCE ADJUSTMENTS**

2 **A. Advertising Expenses**

3 **Q. Please describe I&E's and OCA's proposed adjustment to advertising expenses.**

4 A. I&E and OCA recommend a \$130,000 disallowance of advertising expenses related to the
5 Company's Partners in Power campaign. (I&E St. No. 2, p. 21, OCA St. 1, p 11.) I&E
6 and OCA assert that the Partners in Power campaign is Goodwill or institutional advertising
7 that should not be recoverable from ratepayers.

8
9 **Q. Does the Company agree with the proposed adjustment related to advertising**
10 **expenses?**

11 A. No. As discussed in the rebuttal testimony of PPL Electric Witness Dennis Urban (PPL
12 Electric St. No. 2-R), although the Company classified the Partners in Power campaign as
13 Goodwill or institutional advertising in its response to I&E-RE-II-17-D, the program is
14 functionally aligned with customer operations, not corporate image enhancement. Mr.
15 Urban provides the program description that includes how the benefits of this form of
16 advertising include awareness of tools, programs and resources to help customers take
17 control of their energy use and manage their bills, and how this informational advertising
18 supports customer service and the public interest.

19

B. Bank Charges

Q. Please describe the adjustment I&E is proposing to bank charges.

A. I&E Witness Walker proposes a reduction to bank charges of \$388,000 to reflect the historical three-year average of bank charges (I&E St. No. 1, p. 19), rather than the Company's budgeted FPFTY expense of \$900,000. The OCA does not propose an adjustment to bank charges in its direct testimony.

Q. Please respond to Mr. Walker's proposal.

A. Mr. Walker's proposed adjustment does not take into consideration that banking costs can fluctuate with capital market conditions and historical averages may not accurately reflect forward-looking financing activity. The rebuttal testimony of Mr. Urban (PPL Electric St. No. 2-R) explains the methodology for determining the budgeted amount of bank charges for the FPFTY, and how the budgeted \$900,000 more reasonably reflects the anticipated expense for the FPFTY.

C. Company Sponsorships

Q. Please describe I&E's and OCA's proposed adjustments to Company sponsorship expense.

A. I&E recommends a reduction of \$28,000 to Company sponsorship expense (I&E St. No. 1, p. 21), while OCA recommends a \$120,000 disallowance (OCA Exhibit LKM-13).

1 **Q. What is your response to these recommendations?**

2 A. While the Company believes that the estimated sponsorships expense of \$28,000 in the
3 FPFTY is reasonable and appropriate, to reduce the areas of disagreement, the Company
4 agrees to reflect an adjustment of \$27,510, which is the actual amount of the FPFTY claim,
5 as explained in Mr. Urban's rebuttal testimony (PPL Electric St. No. 2-R). OCA
6 incorrectly asserts that the Company's sponsorship expense in the revenue requirement is
7 \$120,000. That amount, however, is reflective of the total amount for the 12 months ending
8 June 30, 2021, through the HTY (PPL Electric Exhibit DAU-5R [Answer to I&E-RE-I-12-
9 D]). This amount is not included in the cost-of-service calculation for the FPFTY, and,
10 therefore, OCA's proposed adjustment should be rejected.

11
12 **D. Competitive Enhancement Rider Costs**

13 **Q. What is the Company's proposal to address expenses recovered through the**
14 **Competitive Enhancement Rider ("CER")?**

15 A. The CER is designed to recover the costs associated with administering the Eligible
16 Customer List ("ECL"). The Company proposed eliminating the CER from its retail tariff
17 and recovering these expenses through base rates. The Company included \$100,000 in the
18 FPFTY for this expense to reflect this proposal.

19
20 **Q. Does OCA agree with the proposal to recover these expenses through base rates?**

21 A. No. Mr. Morgan states that the costs of compiling the ECL will not be incurred in the
22 FPFTY because they are incurred every five years, and the next update will not occur until

2029 (see OCA St. 1, pp. 17-18). Because the costs will not be incurred in the FPFTY, Mr. Morgan recommends an adjustment to remove the \$100,000 from the revenue requirement. I&E does not propose an adjustment related to this expense.

Q. What is your response?

A. The Company agrees to remove these expenses from the revenue requirement, as explained in the rebuttal testimony of PPL Electric Witness Katelyn Arnold (PPL Electric St. No. 13-R).

E. Economic Development Proposal

Q. CAUSE-PA, OCA, and I&E recommend eliminating PPL Electric's proposed \$400,000 Economic Development expense from the revenue requirement. Do you agree with that adjustment?

A. No. In his rebuttal testimony, PPL Electric Witness Jason Hunt (PPL Electric St. No. 21-R) discusses the appropriateness of implementing the economic development proposal. Mr. Hunt describes how attracting and retaining large customers through economic development in PPL Electric's service territory can lead to lower customer rates by allocating fixed costs over a larger customer base.

1 **Q. Why should Economic Development expenses be considered in the revenue**
2 **requirement?**

3 A. The revenue requirement is intended to recover the reasonable and necessary costs incurred
4 by the Company to provide electric distribution service during the period in which rates
5 will be in effect. The Economic Development expense satisfies this standard because it
6 supports system utilization, long-term load stability, and efficient recovery of fixed
7 distribution costs across a broader customer base.

8
9 **F. Infrastructure Investment and Jobs Act (“IIJA”)**

10 **Q. Please provide an overview of PPL Electric’s IIJA cost recovery proposal.**

11 A. PPL Electric is proposing to recover \$633,000 of costs incurred in 2022 and 2023 related
12 to pursuing IIJA funding opportunities. The Company proposes to recover those costs over
13 three years, resulting in an annual O&M expense in the FPFTY of \$211,000. These costs
14 include consulting and administrative expenses associated with evaluating, preparing, and
15 submitting applications for federal funding.

16
17 **Q. Why did PPL Electric defer these costs and seek recovery in this rate case?**

18 A. As described in the rebuttal testimony of PPL Electric Witness Sharon Leskowsky (PPL
19 Electric St. No. 22-R), PPL Electric’s decision to defer these costs was two-fold. First, as
20 described by Ms. Leskowsky, the costs incurred meet the criteria for cost deferral in that
21 the costs resulted from new legislation that required utilities to incur new, incremental costs
22 that were not part of normal, ongoing O&M prior to the enactment of the legislation.

1 Regulatory assets are commonly used to track deferred costs when expenses are incurred
2 due to external mandates, and the timing of the costs and benefits are not aligned. Second,
3 the Commission explicitly authorized utilities to utilize deferred accounting to track costs
4 related to IIJA in a regulatory asset in Docket No. P-2022-3032929.

5
6 **Q. OCA and I&E recommend disallowance of PPL Electric's IIJA cost amortization on
7 the grounds that the costs are ordinary, anticipated, and recurring. Do you agree?**

8 A. No. From a cost-of-service standpoint, inclusion of the IIJA-related amortization is
9 reasonable and justified because the costs were prudently incurred, incremental, externally
10 driven, and incurred to protect ratepayers' long-term interests. The costs related to IIJA
11 expenses are materially different from ordinary business expenses in that they were
12 triggered by the passing of federal legislation, necessary to preserve eligibility for potential
13 funding under the program, and incremental to existing operating expenses.

14
15 **Q. Please summarize why the amortization of IIJA-related costs should be included in
16 PPL Electric's revenue requirement.**

17 A. The amortization of IIJA-related costs should be included in the revenue requirement
18 because the incremental costs were prudently and reasonably incurred in response to a new
19 federal program and were incurred to protect ratepayer interests by preserving the
20 Company's eligibility for federal infrastructure funding opportunities. At the time these
21 costs were incurred, participation required immediate action and upfront investment.

1 Deferral followed by amortization is the appropriate regulatory mechanism to align cost
2 recognition with the period over which resulting benefits are expected to occur.

3
4 **G. Membership Dues and Subscriptions**

5 **Q. What is PPL Electric proposing with respect to membership dues and subscriptions?**

6 A. In its initial filing, PPL Electric proposed recovery of \$2.8 million in membership dues and
7 subscriptions that were reflected in the Company's FPFTY O&M expense. These costs
8 include payments to industry and trade associations, professional and technical
9 organizations, Chambers of Commerce, training and development groups, and various
10 subscriptions and memberships supporting Company operations. Additional discussion of
11 the amounts included in membership dues and subscriptions is included in the rebuttal
12 testimony of Mr. Urban (PPL Electric St. No. 2-R).

13
14 **Q. What is I&E's position regarding recovery of membership dues and subscriptions?**

15 A. I&E recommends full disallowance of the \$2.8 million membership dues and subscription
16 expense. (I&E St. No. 1, p. 25.)

17
18 **Q. What is the basis for I&E's recommended disallowance?**

19 A. I&E states that PPL Electric provided historical data for membership dues but did not
20 sufficiently identify the specific expenses in the FPFTY, including the individual payees
21 and amounts. I&E asserts that the expenses have not been proven to be necessary for the

1 provision of safe and reliable electric distribution service or to provide benefits to
2 ratepayers. (I&E St. No. 1, p. 26.)
3

4 **Q. Do you agree with this recommendation?**

5 A. No. The FPFTY is intended to represent the level of costs the Company reasonably expects
6 to incur during the FPFTY. These membership dues have been incurred on a recurring
7 basis in the past, are ongoing expenses, and are necessary to support the Company's
8 operations. These payments consist of numerous technical, professional, regulatory,
9 safety, engineering and industry organizations that support ongoing electric distribution
10 operations. It is not reasonable to expect that these costs will cease, materially decline, or
11 become unnecessary in the FPFTY, as I&E's proposed disallowance implies. However, as
12 noted below, PPL Electric has made a correction to its O&M expense budget, which
13 reduces the amount claimed for membership dues and subscriptions by \$808,339.
14

15 **Q. What is OCA's position on recovery of membership dues and subscriptions?**

16 A. OCA recommends disallowance of \$808,000 of membership dues and subscription
17 expenses. (OCA St. 1, p. 17.)
18

19 **Q. Do you agree with this recommendation?**

20 A. Yes. During the discovery process, PPL Electric provided revised Schedules B-2 and B-4
21 that reflected a reduction in the O&M expense budget for membership dues and
22 subscriptions in the amount of \$808,339. In the original 2027 forecast, a higher amount of

1 expenses was forecasted to be incurred in the first quarter related to the timing of payments.
2 This was corrected in the revised schedules and is consistent with the OCA proposed
3 adjustment.
4

5 **H. Payment Transaction Fees**

6 **Q. What is the purpose of including payment transaction fees in base rates?**

7 A. The Company proposes including payment transaction fees in base rates to ensure equitable
8 access to payment options, reduce barriers to timely bill payment, and improve overall
9 revenue collection efficiency. These fees are incurred when customers use widely accepted
10 electronic payment methods, including credit cards, debit cards, and online platforms.
11

12 **Q. I&E accepts inclusion of payment transaction fees in base rates but recommends**
13 **reducing the amount claimed. Does the Company agree with that reduction?**

14 A. No. I&E's recommended reduction is based on rejecting the Company's projected increase
15 in transaction volume following the elimination of transaction-specific customer fees.
16 (I&E St. No. 2, p. 27.) However, as described in the rebuttal testimony of PPL Electric
17 Witness Lisa Norden (PPL Electric St. No. 18-R), that adjustment fails to fully account for
18 changes in customer behavior when price barriers are removed. Historical volumes from
19 periods when customers were charged transaction-specific fees are not predictive of usage
20 when such fees are eliminated. The Company reasonably forecasts increased adoption of
21 electronic payment methods when costs are no longer imposed at the point of use. Ms.

1 Norden expands on the determination of the level of payment transaction fees forecasted
2 in the FPFTY.

3
4 **Q. OCA similarly recommends reducing the claimed expense by applying a lower**
5 **growth rate (see OCA Exhibit LKM-1). Is that a reasonable approach?**

6 A. No. Applying a historical growth rate assumes that customer behavior will remain
7 unchanged despite a fundamental change in pricing structure. Reliance solely on historical
8 data is likely to materially understate future transaction volumes. As described by Ms.
9 Norden, forecasted inputs for this expense were developed considering that: customers are
10 likely to shift to electronic options; electronic payment platforms have become the default
11 method for a broad segment of customers; and usage will accelerate past historical levels
12 when a fee barrier is removed.

13
14 **I. Payroll and Benefits**

15 **Q. What is PPL Electric's approach to calculating payroll expenses in its rate filing?**

16 A. PPL Electric calculated its FPFTY payroll expense based on the average monthly payroll
17 expense per employee and the year-end forecasted number of employees.

18
19 **Q. What objections did I&E raise to PPL Electric's payroll and benefits expense**
20 **calculations?**

21 A. I&E objected to portions of the Company's payroll and benefits calculations. Mr. Keller
22 disputes the employee count used for the FPFTY budget, asserting that an adjustment for

1 vacancies should have been reflected. He applies vacancy adjustments of 4.3% for union
2 and 10.3% for non-union payrolls to payroll expense, benefits, and payroll taxes (I&E St.
3 No. 2, p. 6).
4

5 **Q. What adjustments did OCA recommend regarding PPL Electric's payroll and**
6 **benefits expenses?**

7 A. Mr. Morgan asserts that payroll expenses should be reduced to reflect the phased hiring of
8 23 new employees in the Customer Service group, the staggered nature of recruitment,
9 possible attrition during the training process, and elevated turnover. To calculate his
10 proposed reduction, Mr. Morgan revises the number of new customer service positions to
11 12. (OCA St. 1, p. 8.) Mr. Morgan does not provide supporting evidence that this reduced
12 staffing level is appropriate for calculating payroll expenses for the FPFTY.
13

14 **Q. What is the impact of reflecting these proposed adjustments on the revenue**
15 **requirement?**

16 A. Adjusting the number of employees—whether by implementing a vacancy credit, as
17 proposed by Mr. Keller, or adopting a phased approach towards achieving a full team of
18 customer service representatives, as suggested by Mr. Morgan—reduces the payroll and
19 benefits expenses that are included in the revenue requirement calculation.
20

1 **Q. Does the Company provide support for its employee headcount in its rebuttal**
2 **testimony?**

3 A. Yes. In his rebuttal testimony, Mr. Urban (PPL Electric St. No. 2-R) provides support for
4 the number of employees included in the payroll expense calculation. He discusses the
5 embedded vacancy reserve for certain functional groups as well as the Company's practice
6 of hiring temporary contractors to backfill extended vacancies. He further states the O&M
7 costs of those contractors would exceed the payroll expenses for the 12 employees that
8 OCA Witness Morgan seeks to disallow. These clarifications support the Company's
9 reported number of full-time equivalents ("FTEs") as a reasonable representation of actual
10 staffing levels during the FPFTY.

11
12 **Q. Did Mr. Keller and Mr. Morgan make any other recommendations to adjust payroll**
13 **and benefits expenses?**

14 A. Yes. Mr. Keller recommended a 50% disallowance of the Company's claim for cash
15 awards under the incentive compensation plan, citing that a portion of these awards are tied
16 to earnings per share. Additionally, Mr. Keller recommends a complete disallowance of
17 equity awards, asserting that stock-based compensation does not benefit ratepayers because
18 they are granted solely based on financial performance goals. (I&E St. No. 2, p. 19.)
19 Similarly, Mr. Morgan recommends a 50% disallowance of all incentive compensation
20 expense. Mr. Morgan opines that incentive plans whose payouts are based on earnings
21 goals and increasing shareholder value are not recoverable from ratepayers (see OCA
22 Exhibit LKM-5).

1 **Q. Do you have any overall comments in response to Mr. Keller’s and Mr. Morgan’s**
2 **testimonies on incentive compensation?**

3 A. Yes. The Company provides additional information regarding the incentive compensation
4 plan in the rebuttal testimony of PPL Electric Witness Vincent Poplaski (PPL Electric St.
5 No. 23-R). Mr. Poplaski describes the cash and equity compensation plan in detail as well
6 as how the plan’s metrics are tied to improvements in operational effectiveness to deliver
7 benefits to ratepayers. It should be noted that the Company must pay market-based
8 compensation to attract and retain employees. If the Company fails to pay competitive
9 compensation and benefits, it will invariably be unable to attract and retain skilled labor.
10 Therefore, the Company has programs in place to ensure that its compensation and benefits
11 offerings are consistent with the market.

12
13 **Q. Are there examples of other regulatory jurisdictions that have acknowledged the**
14 **importance of total compensation to attracting and retaining employees?**

15 A. Yes. Delaware and Minnesota provide examples. The Delaware Public Service
16 Commission, in examining Delmarva Power & Light’s (“DP&L”) incentive compensation
17 plan, stated that DP&L “has demonstrated that plans of this type . . . are commonly used in
18 the industry to attract and retain skilled employees,” and further reasoned that since “the
19 hiring and retention of skilled workers is important” in a competitive marketplace and that
20 the incentive plan “will assist in that effort,” the incentive plan is beneficial for ratepayers.⁴

⁴ Delaware Public Service Commission Docket No. 20-0149, Order No. 9953, at 32.

1 In Minnesota, the Public Utilities Commission (“MPUC”) approved Minnesota Power’s
2 (“MP”) proposed compensation expenses that included “High-Performance Awards.”
3 These awards were designed to reward high performing employees who have furthered
4 MP’s strategic objectives. The MPUC found that MP’s compensation expenses are
5 reasonable because they will allow MP to “keep up with rising expenses and remain market
6 competitive.” The MPUC further stated that in order to “attract and retain skilled
7 employees, [Minnesota Power] must offer competitive compensation.”⁵
8

9 **Q. Is the basis for I&E’s and OCA’s disallowances reasonable?**

10 A. No. Both I&E and OCA apply arbitrary percentage “haircuts” to aspects of the incentive
11 compensation plan without plan-specific analysis. I&E’s and OCA’s recommendations,
12 therefore, are unsupported by empirical analysis.
13

14 **Q. Why is the exclusion of incentive compensation based on financial performance goals**
15 **unreasonable?**

16 A. As described by Mr. Poplaski, the financial metrics used to determine incentive
17 compensation promote cost discipline, productivity, and effective risk management. These
18 practices contribute to cost efficiency and the maintenance of stable utility rates, making
19 such expenses justified for inclusion in customer rates.

⁵ Minnesota Public Utility Commission Docket No. GR-21-335, Order dated 2/28/23, at 27-28.

1 **Q. Do any other Company proposals impact payroll and benefits expenses?**

2 A. Yes. In its initial filing, the Company proposed to recover salaries associated with its
3 Universal Service and Energy Conservation Plan (“USECP”) through the Universal
4 Service Rider (“USR”). A *pro forma* adjustment to the calculated payroll and benefit
5 expense was made to remove \$1,400,000 of salaries attributed to the administering of the
6 program from base rates.

7
8 **Q. Do any parties object to the recovery of these salaries and wages through the USR
9 rather than in base rates?**

10 A. Yes, CAUSE-PA, I&E, and OCA recommend that salaries continue to be recovered
11 through base rates and not through the rider mechanism. Ms. Norden discusses the
12 Company’s proposal in PPL Electric St. No. 18-R.

13
14 **Q. If the USR salaries continue to be recovered through base rates, do CAUSE-PA, OCA,
15 and I&E appropriately reflect the adjustment to do so?**

16 A. CAUSE-PA and OCA have, but not I&E. Specifically, Mr. Morgan recognizes that a *pro*
17 *forma* adjustment was made for the USR salaries and wages and if the recommendation to
18 recover the expense through base rates is approved, an increase to payroll expense in the
19 amount of \$1,400,000 must be made when calculating the revenue requirement. (OCA St.
20 1, p. 25.) CAUSE-PA Witness Patrick Cicero acknowledges that the application includes
21 a direct allocation of \$1.4 million in employee costs to the USR, rather than reflecting those
22 costs in base rates. (CAUSE-PA St. No. 1, p. 134.)

1 I&E, however, does not include an adjustment to increase payroll expense when
2 recommending the disallowance of the Company's proposal to recover USR salaries
3 through the rider mechanism. (I&E St. No. 2, p. 16.)
4

5 **Q. Why was I&E Witness Keller incorrect to not reflect an increase to the revenue**
6 **requirement for this proposed adjustment?**

7 A. In the Company's response to I&E-RE-II-7-D, PPL Electric Witnesses Mr. Urban and Ms.
8 Norden state:

9 PPL Electric Schedules D-5 and Exhibit II-D-10 are at a total
10 company level and include all wages and benefits and,
11 therefore, do not include a reduction for Universal Service
12 Rider salaries shown in Schedule D-11.

13 Schedule D-5 shows the *pro forma* adjustment for wages and benefits, and Filing
14 Requirement II-D-10 provides the payroll and employee benefit data for the HTY, the
15 Future Test Year ("FTY"), and the FPFTY. These schedules do not include the impacts of
16 the *pro forma* adjustment for USR salaries. Mr. Keller apparently mistook this response
17 to mean that the reduction in salaries and wages for the amounts proposed to be recovered
18 via the USR rider are not excluded from the calculation of the FPFTY revenue requirement,
19 when in fact they are.

20 Additionally, the *pro forma* adjustment to reflect the recovery of USR salaries
21 through the rider mechanism is shown on Schedule D-11 and is included in the calculation
22 of the FPFTY revenue requirement as a reduction in operating expense. Therefore, should
23 the Commission deny the proposal to recover the USR salaries through the rider

1 mechanism, an upward adjustment to salaries and wages in the amount of \$1,400,000 must
2 be made in the recalculation of the revenue requirement to allow for recovery of this cost,
3 as correctly recognized by Mr. Morgan.

4
5 **J. Rate Case Expense**

6 **Q. Is the normalization of rate case expenses being disputed in this proceeding?**

7 A. No, OCA and I&E do not challenge the amount or the appropriateness of normalizing rate
8 case expenses into base rates. The parties agree that rate case expense is a recurring cost
9 of providing regulated electric distribution service and is properly reflected as a normalized
10 component of the revenue requirement.

11
12 **Q. What aspect of the normalized rate case expense is in dispute?**

13 A. The sole issue in dispute is the appropriate annualized level of rate case expenses to be
14 included in base rates. OCA and I&E propose calculating the normalized amount using a
15 longer normalization period than the Company's proposed three-year normalizing period.

16
17 **Q. What rate case expense recovery is the Company proposing in this application?**

18 A. PPL Electric is proposing normalization of approximately \$2.2 million in rate case
19 expenses into base rates. To determine a normalized expense, the Company divided the
20 estimated rate case expenses incurred for this proceeding by three years, reflecting the
21 Company's anticipated three-year filing frequency. This results in an ongoing annual rate
22 case expense of approximately \$741,000 reflected in the FPFTY revenue requirement.

1
2 **Q. Why is a three-year normalization period reasonable for the purposes of**
3 **normalization?**

4 A. As explained by PPL Electric Witness Bethany L. Johnson (PPL Electric St. No. 5-R), a
5 three-year normalization period reasonably reflects the frequency with which PPL Electric
6 anticipates filing base rate cases on a going-forward basis and provides a realistic estimate
7 of the ongoing annual level of rate case expense that must be recovered in rates. It is
8 supported by both historical filing experience over a longer period (excluding the most
9 recent, uncharacteristically long period between cases) and expected future regulatory
10 activity.

11
12 **Q. OCA and I&E argue for a longer normalization period based on historical filing**
13 **frequency. Why does the Company disagree?**

14 A. OCA and I&E rely on only the three most recent filings to argue for a longer normalization
15 period. (I&E St. No. 1, p. 7.) There is no requirement, however, to limit the review in this
16 manner. Limiting the analysis to the three most recent filings skews the analysis by
17 including the most recent 10-year period between Company rate cases, which is an outlier
18 when compared to the prior five cases (as discussed below) and results in a normalized
19 amount that is not representative of the Company's overall rate case filing cadence.

20

1 **Q. What does a broader historical review show regarding filing frequency?**

2 A. When the five most recent filings prior to the current case are considered, the approximate
3 filing intervals were:

- 4 • 2012 to 2015⁶: ~36 months
- 5 • 2010 to 2012⁷: ~24 months
- 6 • 2007 to 2010⁸: ~36 months
- 7 • 2004⁹ to 2007¹⁰: ~36 months

8 This produces an average filing interval of approximately 33 months, which is consistent
9 with the Company's proposed three-year normalization period.

10
11 **Q. Based on the record, is PPL Electric's proposed normalization for rate case expense**
12 **justified?**

13 A. Yes. PPL Electric's proposed approach is justified because normalization of rate case
14 expense is undisputed in this proceeding, and the three-year normalization period proposed
15 by the Company reasonably reflects both historical experience and the Company's
16 expected future filing frequency. A broader review of the Company's filing history
17 demonstrates an average interval of approximately 2.75 years (i.e., 33 months). The
18 Company's proposal therefore produces a representative, forward-looking annual expense
19 level. Accordingly, the Commission should accept PPL Electric's proposed normalized

⁶ See *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2015-2469275.

⁷ See *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2290597.

⁸ See *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694.

⁹ See *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00049255.

¹⁰ See *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00072155.

1 rate case expense as reasonable and supported by substantial evidence. For additional
2 discussion, see the rebuttal testimony of PPL Electric Witness Bethany L. Johnson (PPL
3 Electric St. No. 5-R).

4
5 **K. Research and Development**

6 **Q. OCA recommends a disallowance of the increase in PPL Electric's Research and**
7 **Development ("R&D") expense on the basis that the Company "has not adequately**
8 **explained the increase." Do you agree?**

9 A. No. PPL Electric has adequately explained both the composition and purpose of the
10 increase in R&D expenses. As described more fully in the rebuttal testimony of Mr. Urban
11 (PPL Electric St. No. 2-R), the increase reflects targeted, utility-specific research
12 investments that support system reliability, safety, and operational efficiency. The
13 recommendation to disallow the increase is based on a misunderstanding of the nature of
14 the costs rather than any showing that the expenses were imprudently incurred or are
15 unsupported.

16
17 **Q. What are the primary components of the R&D expense increase?**

18 A. As discussed by Mr. Urban, the increase consists of two principal elements:

- 19 1. Approximately \$200,000 associated with participation in the National Electric Energy
20 Testing, Research, and Applications Center ("NEETRAC"); and
- 21 2. Approximately \$121,000 of internal labor and support costs necessary to evaluate,
22 implement, and integrate R&D findings into PPL Electric's distribution operations.

1 Together, these costs represent a modest and focused enhancement to the Company's
2 existing R&D efforts.

3
4 **Q. Why is participation in NEETRAC reasonable from a ratemaking perspective?**

5 A. NEETRAC is a nationally recognized, nonprofit research consortium focused on grid
6 efficiency, distribution system reliability, and safety. Participation provides access to
7 independent testing results, peer utility collaboration, and research outcomes that
8 individual utilities could not efficiently replicate on their own.

9
10 **Q. OCA requests that the Company more fully explain why this cost increased. Please**
11 **respond.**

12 A. The Company offers an explanation as to the increase in cost in the rebuttal testimony of
13 Mr. Urban (PPL Electric St. No. 2-R).

14
15 **Q. Why are internal costs appropriately included as R&D expenses?**

16 A. Internal R&D costs are an integral component of any effective research program. PPL
17 Electric must devote internal technical, engineering, and analytical resources to participate
18 meaningfully in research initiatives, evaluate research results, translate findings into
19 operational practices, and determine applicability to the Company's distribution system.

20 Without internal resources, participation in external research organizations would provide
21 little practical value. These costs, therefore, reflect labor necessary to realize the benefits
22 of the R&D investment, not discretionary overhead.

1
2 **Q. OCA requests that the Company more fully explain why more coordination and**
3 **participation with the T&D businesses would result in an increase in expenses of**
4 **\$121,000. Please respond.**

5 A. The Company explains the increased costs associated with the coordination of efforts and
6 participation by the T&D businesses in the rebuttal testimony of Mr. Urban (PPL Electric
7 St. No. 2-R).

8
9 **Q. Please summarize your position on the R&D expense increase.**

10 A. The Commission should reject Mr. Morgan's recommendation to disallow these R&D
11 expenses. The source and purpose of the increase in R&D expenses have been adequately
12 explained by the Company in its direct and rebuttal testimonies. In addition, the increase
13 in R&D expenses in the FPFTY is reasonable because, as Mr. Urban explains, the
14 incurrence of such costs is consistent with industry practice, participation in NEETRAC
15 provides meaningful operational and reliability benefits, and internal R&D labor is
16 necessary to realize those benefits.

17
18 **L. Storm Damage Expense**

19 **Q. Please describe the Company's proposal regarding storm damage expenses.**

20 A. PPL Electric seeks to better align its Storm Damage Expense Rider ("SDER") baseline
21 amount with actual costs incurred in recent storm events and anticipated future costs. The
22 Company proposes increasing the baseline for recovery of expenses under the SDER to

1 \$42.5 million. \$32 million of that amount is related to storm damage expenses resulting
2 from Commission reportable storm events. In addition, the Company also proposes to
3 include storm-related expenses from non-reportable storm events in the SDER and has
4 reflected \$10.5 million attributed to non-reportable storm damage expenses in its
5 distribution base rates.

6
7 **Q. What is the SDER?**

8 A. The SDER mechanism allows for the recovery of eligible storm expenses from
9 Commission reportable storms¹¹ when those costs exceed the amount of storm damage
10 expense recovered through the Company's base distribution rates. There is a cap on the
11 amount of revenue that can be recovered through the SDER. This cap, calculated annually,
12 cannot exceed 3% of the intrastate operating revenues billed to customers. Customers are
13 offered additional audit protections as described in the General Tariff – Storm Damage
14 Expense Rider¹²:

15 *The SDER is subject to audit at intervals determined by the Commission.*
16 *Any cost determined by the Commission not to comply with any provision*
17 *of 66 Pa C.S. §§ 1307, et seq., shall be credited to customer accounts. The*
18 *SDER is subject to annual reconciliation based on a reconciliation period*
19 *ending October 31 of each year. The revenue received under the SDER for*
20 *the reconciliation (C)period will be compared to PPL Electric's eligible*
21 *costs for that period. The difference between revenue and costs will be*
22 *recouped or refunded, as appropriate, in accordance with Section 1307(e),*
23 *over a one-year period.*
24

¹¹ A reportable storm is defined as an interruption of electric service resulting from conditions beyond the control of the Company which affect at least 10% of the Company's customers during the course of the event for a duration of five minutes each or greater (see 52 Pa. Code §57.192).

¹² Supplement No. 216 Electric Pa. P.U.C. No. 201 – SDER pages 19Z.20–19Z.25.

1 Each year, PPL Electric reconciles actual eligible storm costs to SDER revenues for a 12-
2 month period ending October 31 and refunds or surcharges the difference with statutory
3 interest under §1307(e). The SDER mechanism benefits customers because it ensures they
4 only pay verified, prudently incurred storm-response costs, and it benefits the Company
5 because it provides a timely and predictable mechanism to recover eligible expenses
6 needed to maintain system reliability.

7
8 **Q. Does I&E agree with the Company's SDER proposals?**

9 A. No. Mr. Walker recommends imposing a threshold for reportable storm expenses of
10 \$22.01 million based on a three-year historical average of expenses. (I&E St. No. 1, p. 15.)
11 In addition, he recommends that storm damage expenses related to non-reportable storms
12 of \$10.5 million continue to be excluded from the SDER mechanism.

13
14 **Q. Is using a three-year historical average to determine the baseline threshold for**
15 **reportable storm damage expenses reasonable?**

16 A. No, not based on recent trends in storm activity and costs. The use of a three-year historical
17 average does not adequately account for recent increases in extreme weather events or
18 rising storm remediation costs. Use of a three-year average would introduce additional
19 regulatory lag for the Company related to these expenses, the magnitude and timing of
20 which are largely outside of the Company's control.

21

1 **Q. How does the Company’s proposed threshold address regulatory lag?**

2 A. As described by Ms. Johnson (PPL Electric St. No. 5-R) and PPL Electric Witness Katelyn
3 Arnold (PPL Electric St. No. 13-R), the Company’s proposed \$42.5 million threshold (\$32
4 million in Commission reportable storm costs and \$10.5 million in non-reportable storm
5 costs) allows for more timely recovery of storm-related expenses by establishing a
6 reasonable baseline that reflects the Company’s recent experience with severe weather
7 events. By setting the threshold at a level that matches this recent experience, the Company
8 can recover expenses in a timely manner through the SDER, rather than waiting for future
9 base rate cases. This smooths the recovery of these expenses rather than creating a large
10 deferral that must be resolved in a future rate case.

11
12 **Q. Why is timely recovery of storm damage expenses important for PPL Electric and its**
13 **customers?**

14 A. Timely recovery contributes to the financial stability of the Company and allows for
15 continued investment in system reliability and resiliency. When recovery is delayed, the
16 Company must carry unrecovered costs for extended periods, which can strain resources.
17 Prompt recovery through the SDER enables the Company to respond effectively to storm
18 events, maintain adequate cash flow, and avoid passing unnecessary carrying costs on to
19 customers.

1 **Q. How does the \$42.5 million threshold benefit ratepayers?**

2 A. By allowing for timely and predictable recovery of storm-related costs, the \$42.5 million
3 threshold helps stabilize rates and reduces the risk of large, unexpected rate increases in
4 future base rate cases, as storm costs are recovered closer to when they are incurred. This
5 approach provides transparency and regulatory oversight, benefiting both the Company
6 and its customers.

7
8 **Q. Why is PPL Electric proposing to include non-reportable storm damage expenses in**
9 **the SDER?**

10 A. PPL Electric is proposing to include non-reportable storm damage expenses in the SDER
11 to ensure that all storm-related costs, regardless of severity, are recovered in a timely and
12 transparent manner. Including these expenses in the SDER allows for consistent regulatory
13 treatment, reduces the risk of regulatory lag, and provides the Company with the financial
14 flexibility needed to respond effectively to all storm events. This is further explained in
15 the rebuttal testimony of Ms. Arnold (see PPL Electric St. No. 13-R).

16
17 **Q. How does including non-reportable storm damage expenses in the SDER benefit**
18 **customers?**

19 A. Including non-reportable storm damage expenses in the SDER benefits customers in
20 several ways. First, it promotes rate stability and transparency by ensuring that recovery
21 of these costs is subject to regular Commission oversight and that customers are only
22 charged for actual expenses incurred. Second, and importantly, the SDER mechanism

1 provides a clear, auditable mechanism for recovery that ensures that customers do not pay
2 storm damage costs that did not occur. If there are periods with fewer or less severe storms,
3 the SDER will reflect the actual expenses through the rider reconciliation process, so
4 customers are not burdened with costs that were not incurred by the Company.

5
6 **Q. Does the Company propose including any other storm-related expenses in base rates?**

7 A. Yes. PPL Electric is proposing to recover \$11.336 million of storm damage expenses that
8 were incurred between November 1, 2023, and October 31, 2024, and that exceeded the
9 3% cap on storm expenses allowed to be recovered in the SDER. The regulatory asset for
10 these expenses is requested to be recovered over a three-year period, resulting in
11 \$3,778,723 of amortization in the FPFTY revenue requirement.

12
13 **Q. I&E recommends using a longer amortization period than proposed by the Company.**
14 **Do you agree?**

15 A. No. The Company's three-year amortization period aligns with the current basis upon
16 which deferred storm costs are recovered and balances cost recovery and ratepayer impact.
17 As discussed above, a three-year amortization period is also supported by an analysis of
18 rate case intervals over a longer period than the historical filing frequency lookback used
19 by I&E in its analysis.

20

1 **Q. Did the OCA oppose PPL Electric’s proposals regarding storm damage expense**
2 **recovery in this proceeding?**

3 A. No. In its direct testimony, the OCA did not oppose PPL Electric’s proposals related to
4 storm damage expense recovery.
5

6 **M. Vegetation Management**

7 **Q. What did I&E recommend for vegetation management expense, and on what basis?**

8 A. I&E recommends reducing PPL Electric’s FPFTY vegetation management expense from
9 approximately \$50.00 million to \$34.42 million, basing its recommendation on a three-
10 year historical average of fiscal year 2023, fiscal year 2024, and the HTY (i.e., calendar
11 year 2025) actuals (i.e., the average of \$37.4 million, \$30.3 million, and \$35.5 million)
12 (I&E St. No. 1, p. 27-28). I&E asserts that this average reflects a “reasonable” level for
13 ratemaking purposes.
14

15 **Q. How does this impact the revenue requirement?**

16 A. This \$15.579 million downward adjustment directly lowers O&M in the revenue
17 requirement and, after tax gross-up effects, produces a materially larger reduction in
18 required revenues than is consistent with the plan recommended in direct testimony by PPL
19 Electric Witness Nicole Howell (PPL Electric St. No. 17). I&E’s proposal would not
20 adequately fund the Company’s vegetation management program.
21

1 **Q. Why is a three-year average an incorrect basis for setting FPFTY O&M in revenue**
2 **requirement terms?**

3 A. The revenue requirement should reflect the forward-looking cost of the work that will be
4 performed in the FPFTY, not a historical, nominal average of prior period spending. Ms.
5 Howell's testimony details the increased FPFTY work volume and unit costs associated
6 with vegetation management. A simple historical average omits these incremental drivers,
7 thereby understating anticipated O&M requirements in the FPFTY and unreasonably
8 lowering the revenue requirement. Refer to Ms. Howell's rebuttal testimony for
9 information on the development of the budget for the vegetation management plan (PPL
10 Electric St. No. 17-R).

11
12 **Q. What revenue requirement risk arises if the Commission adopts I&E's three-year**
13 **historical average?**

14 A. The adoption of a three-year historical average would create a shortfall relative to the level
15 of spending required for the Company's vegetation management program, leading to either
16 the deferral or curtailment of planned tree trimming and vegetation removal. Such program
17 underfunding could lead to subsequent increased execution risk related to work delayed
18 until future periods, and the potential for cost increases elsewhere (e.g., outage restoration
19 expense). I&E does not reflect either of those risks in its proposal.

20

1 **Q. What is your recommendation to align the revenue with the Company's vegetation**
2 **management plan?**

3 A. I recommend the Commission rely on the Company's forward-looking vegetation
4 management plan and cost estimate and reject I&E's proposal to instead rely on a three-
5 year historical average of vegetation management costs. Approval of the Company's
6 proposal ensures the revenue requirement matches the planned work and avoids
7 underfunding the program, which would increase the risks related to vegetation
8 management.

9
10 **Q. Did the OCA address PPL Electric's vegetation management proposal in this case?**

11 A. Yes. Mr. Morgan summarized PPL Electric's vegetation management program and
12 requested that the Company provide additional information. However, he did not propose
13 an adjustment to the O&M expense level.

14
15 **IV. TAXES OTHER THAN INCOME TAXES**

16 **A. Public Utility Realty Tax ("PURTA")**

17 **Q. OCA recommends removal of PPL Electric's PURTA expense based on a notice**
18 **indicating the PURTA millage rate will be zero in 2025 and 2026. Do you agree?**

19 A. No. OCA misinterprets the applicability of the Pennsylvania Department of Revenue
20 notice. While the notice states that the PURTA millage rate will be zero for calendar years

2025 and 2026,¹³ that millage rate applies to the PURTA-related Gross Receipts Tax (“GRT”) surcharge, not to the PURTA obligation itself. The purpose of the notice is to inform taxpayers that the GRT surcharge calculation will not produce an additional GRT adjustment during those years. The notice does not eliminate PURTA assessments on utility real property or waive a utility’s obligation to pay PURTA based on property valuation. Accordingly, the recommendation to eliminate the Company’s PURTA expense from the revenue requirement should be rejected. Further clarification of the inclusion of PURTA expense can be found in the rebuttal testimony of PPL Electric Witness Andrew Elmore (PPL Electric St. No. 12-R).

Q. Why is the inclusion of PURTA expense in the revenue requirement appropriate under cost-of service ratemaking?

A. The revenue requirement must reflect reasonably known and unavoidable tax obligations the utility expects to incur during the tax year. PURTA is a statutorily imposed tax associated with the ownership and use of real property and remains in effect during the FPFTY. Excluding PURTA would understate the Company’s tax obligations and not allow for cost recovery of this unavoidable tax.

¹³ Pennsylvania Bulletin, Public Utility Realty Tax Act (PURTA); Surcharge Rate Notice for the Tax Year Beginning January 1, 2026, 55 Pa. B. 6807 (Sept. 20, 2025).

B. Payroll Taxes

Q. What is PPL Electric's approach to calculating payroll tax expense in its filing?

A. The Company uses a composite rate of 8.5% to estimate payroll tax expense. This includes 8.0% for Social Security and Medicare taxes, 0.1% for federal unemployment tax, and 0.4% for state unemployment tax.

Q. What objections did I&E raise to PPL Electric's payroll tax expense calculations?

A. According to Mr. Keller, "[t]he Company's 8.5% claim for total payroll taxes is unsupported, particularly since the combination of Social Security and Medicare taxes should be 7.65%, and not the 8.0% total that PPL Electric has indicated." (I&E St. No. 2, p. 11.)

Q. What adjustments did OCA recommend regarding PPL Electric's payroll and benefits expenses?

A. Mr. Morgan recommends an adjustment to payroll tax expense to reflect an estimated tax rate of 7.65%, or the combined FICA rate.

Q. What is your response?

A. The Company agrees to adjust payroll tax expense to reflect 7.65% of wages and salaries as discussed by PPL Electric Witness Andrew Elmore (PPL Electric St. No. 12-R).

1 **Q. Did Mr. Keller and Mr. Morgan make any other recommendations to adjust payroll**
2 **tax expense?**

3 A. Yes. As discussed above, Mr. Keller and Mr. Morgan recommended adjustments to payroll
4 expense. Both I&E and the OCA included in their recommendations an adjustment to
5 payroll taxes to reflect their respective adjustments to total payroll. (I&E St. No. 2, p. 11;
6 OCA Exhibit LKM-4).

7
8 **Q. Is it necessary to adjust payroll tax expense if the Commission does not agree with**
9 **I&E's and OCA's proposed changes to payroll?**

10 A. No, it is not necessary to further adjust payroll tax expense if the underlying payroll levels
11 are not changed by the Commission, because payroll tax expense is a direct function of
12 total payroll. Therefore, unless an adjustment is made to payroll expense itself, there is no
13 basis to modify the corresponding payroll tax expense. If the recommended changes to
14 payroll are not adopted, the payroll tax expense should remain at 7.65% of payroll.

15 **V. REVENUE REQUIREMENT**

16 **Q. Did the Company propose any adjustments to the revenue requirement provided in**
17 **its initial rate case filing during the discovery process?**

18 A. Yes. As detailed in the rebuttal testimony of Mr. Urban (PPL Electric St. No. 2-R), the
19 Company made four adjustments to its initial rate case filing during discovery.
20 Adjustments were made to operating revenues, O&M, depreciation expense, and cash
21 working capital. The impact of these adjustments on accumulated depreciation,

1 accumulated deferred income taxes, interest expense, and income taxes were included in
2 the proposed adjustments. After reflecting those adjustments, the proposed increase to net
3 operating revenues in this proceeding is \$389,319,529.
4

5 **Q. Did I&E and OCA consider these adjustments when calculating their recommended**
6 **rate increases?**

7 A. No. Both I&E and OCA made their recommendations based on figures included in the
8 original filing and did not reflect adjustments the Company made in the discovery process.
9

10 **Q. Have you recalculated the recommended rate increases proposed by I&E and OCA**
11 **to reflect the updates the Company made in discovery?**

12 A. Yes. I have updated the calculations prepared by OCA and I&E to include the adjustments
13 made to operating income, O&M expenses, and depreciation in discovery and the
14 corresponding impacts to rate base, interest expense and taxes. As shown on PPL Electric
15 Exhibit DSD-2R, when OCA's recommended adjustments are made to the revenue
16 requirement calculation updated in discovery, OCA's recommended rate increase of
17 \$150,035,000 (OCA St. 1, Exhibit LKM-1) increases by \$34,251,000 to \$184,286,000. As
18 shown on PPL Electric Exhibit DSD-3R, when I&E's recommended adjustments are made
19 to the revenue requirement calculation updated in discovery, I&E's recommended rate
20 increase of \$258,878,000 (I&E St. No. 1, p. 3) increases by \$35,339,000 to \$294,217,000.
21

1 **Q. Were any deficiencies identified in the calculations presented by I&E and OCA?**

2 A. Yes. Corrections to the cash working capital determination in both calculations were
3 identified. These corrections are discussed in the rebuttal testimony of Ms. Arnold. PPL
4 Electric Exhibits DSD-2R and DSD-3R do not reflect adjustments for those corrections.
5

6 **Q. What other corrections should be made to calculate the revenue requirement by**
7 **OCA?**

8 A. A further correction to rate base is needed in OCA's calculation. In Mr. Morgan's
9 calculation of rate base, he reflects an adjustment to accumulated depreciation to reflect
10 OCA's proposed adjustment to depreciation expense. Mr. Morgan, however, did not carry
11 this adjustment forward to determine the impact on accumulated deferred income taxes
12 ("ADIT") and the related normalization adjustment necessary to fully reflect the impact of
13 the recommended adjustment on rate base. PPL Electric Exhibit DSD-2R does not reflect
14 an adjustment for this correction. Should any adjustment to depreciation expense be
15 approved by the Commission in this proceeding, the calculation of rate base should also
16 include a recalculation of ADIT.
17

18 **Q. Please summarize the adjustments the Company is proposing after considering the**
19 **direct testimony submitted by the OCA and I&E.**

20 A. The Company is proposing an adjustment to capital and O&M in the FPFTY to move
21 amounts related to the EV Program budget from capital to expense. In addition, as
22 discussed above, the Company is proposing adjustments to include an increase to late

1 payment revenue, and adjustments to O&M to reduce company sponsorships and remove
2 the recovery of expenses for eligible customer lists. The impact of these adjustments on
3 accumulated depreciation, accumulated deferred income taxes, interest expense, and
4 income taxes was included in the proposed adjustments. These adjustments are reflected
5 on Schedules C-1 and D-1 for the FPFTY as revised for rebuttal. To be clear, these
6 adjustments are made in addition to those provided in discovery, attached to the rebuttal
7 testimony of Dennis A. Urban (PPL Electric St. No. 2-R) as PPL Electric Exhibit DAU-
8 2R.

9
10 **Q. Is the Company proposing any other adjustments?**

11 A. Yes. The Company is proposing an adjustment to the gross up factor to include the
12 reduction in gross receipts tax related to the increase in uncollectible amounts resulting
13 from the proposed rate increase. Additionally, the Company is making an adjustment to
14 factor in additional late payment charge revenue of \$1,699,050 under proposed rates, as
15 recommended by I&E Witness Cline (see I&E St. No. 4, p. 3).

16
17 **Q. Based on these additional adjustments, what is the revised proposed increase to net
18 operating revenues requested in this proceeding.**

19 A. As shown on Schedule D-1 for the FPFTY as revised for rebuttal, a copy of which is
20 attached as PPL Electric Exhibit DSD-1R, the proposed increase in this proceeding is
21 \$384,522,323.

22

1 **VI. INTEREST SYNCHRONIZATION**

2 **Q. Please explain what is meant by “interest synchronization.”**

3 A. Interest synchronization is the regulatory process used to align the utility’s embedded cost
4 of long-term debt with the level of rate base included for ratemaking purposes. The interest
5 deduction is calculated by applying the Commission-authorized cost of long-term debt to
6 rate base. This normalized interest deduction ensures that customers receive the proper tax
7 benefits associated with the debt component used to finance rate base.

8
9 **Q. How often should the interest synchronization be updated in a rate case?**

10 A. The interest synchronization should be updated every time rate base is updated. This
11 ensures that the tax component of the revenue requirement is aligned with the rate base the
12 Commission is using to set rates.

13
14 **Q. Has the interest synchronization been updated in this proceeding?**

15 A. Yes. The Company updated the calculation of the interest synchronization for the
16 adjustments proposed in both discovery and in rebuttal. Including adjustments agreed to
17 herein, the Company calculated \$1,699,050 of interest expense, which is included in the
18 calculation of federal and state income taxes reflected in the calculation of operating
19 income in DSD-1R. The interest synchronization should be updated automatically with
20 every rate base update in the case.

1 **VII. CONCLUSION**

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

3 **A. Yes, it does.**

Operating Income
Pro Forma at Present and Proposed Rates
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.		(1) T & D Pro Forma at Present Rates (Exhibit D-1)	(2) Less: T Pro Forma at Present Rates	(3) Pro Forma at Present Rates	(4) PPUC Jurisdictional Rate Increase	(5) Pro Forma at Proposed Rates
1a	Operating Revenues	\$ 1,010,491	\$ 0	\$ 1,010,491	\$ 384,522	\$ 1,395,013
1b	Other Non-Rate Revenue	1,037,566	(977,437)	60,129	1,699	61,828
1c	Total Operating Revenue	2,048,057	(977,437)	1,070,620	386,221	1,456,841
	Operating Expenses					
2	Operation and Maintenance	500,374	(73,243)	427,131	7,532	434,664
3	Depreciation	549,401	(225,245)	324,156	-	324,156
4	Regulatory Debits/Credits	3,990	(0)	3,990	-	3,990
	Provision for Taxes					
5	Taxes Other Than Income	69,060	(4,087)	64,973	22,408	87,382
	Income Taxes					
6	Federal	16,330	(38,870)	(22,540)	69,402	46,862
7	State	(2,991)	(7,730)	(10,721)	25,795	15,074
8	Deferred Income Taxes	136,535	(90,065)	46,470	-	46,470
9	Investment Tax Credit	(31)	16	(15)	-	(15)
10	Total Taxes	218,903	(140,735)	78,168	117,605	195,773
11	(Gain)/Loss from Disposition of Utility Plant	-	-	-	-	-
12	Total Operating Expenses	1,272,669	(439,223)	833,445	125,137	958,582
13	Operating Income	\$ 775,388	\$ (538,214)	\$ 237,175	\$ 261,084	\$ 498,260

Operating Income
Recalculation of OCA Revenue Requirement Reflecting Discovery Updates
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	AS FILED			AS UPDATED IN DISCOVERY			OCA CALCULATION FROM DIRECT TESTIMONY					OCA CALCULATION WITH UPDATES FROM DISCOVERY				
		Proforma at Present Rates	Rate Increase	Proforma at Proposed Rates	Proforma at Present Rates	Rate Increase	Proforma at Proposed Rates	Company Proforma at Present Rates	OCA Recommended Adjustments	OCA Proforma at Present Rates	Rate Increase	OCA Proforma at Proposed Rates	Company Proforma at Present Rates	OCA Recommended Adjustments	OCA Proforma at Present Rates	Rate Increase	OCA Proforma at Proposed Rates*
1	Operating Revenues	1,005,772	356,271	1,362,043	1,010,491	389,320	1,399,811	1,005,772		1,005,772	150,033	1,155,805	1,010,491		1,010,491	184,286	1,194,777
2	Operating Expenses																
2	Operation and Maintenance	431,937	6,974	438,911	431,129	7,621	438,750	431,937	(3,508)	428,429	2,937	431,366	431,129	(2,508)	428,621	3,608	432,228
3	Depreciation and Amortization Expense	289,596		289,596	324,180		324,180	289,596	(4,247)	285,349		285,349	324,180	(4,247)	319,933		319,933
4	Taxes Other Than Income	68,847	21,020	89,867	67,337	22,970	90,307	68,847	(1,461)	67,386	8,852	76,238	67,337	(1,461)	65,876	10,873	76,749
5	Total Operating Expenses	790,381	27,994	818,375	822,646	30,591	853,237	790,381	(9,216)	781,165	11,789	792,954	822,646	(8,216)	814,430	14,480	828,911
6	Other Operating Income	60,129	-	60,129	60,129	-	60,129	60,129		60,129	-	60,129	60,129		60,129	-	60,129
7	Interest on Long-Term Debt	129,739		129,739	129,807		129,739	129,739	41,803	171,541		171,541	129,807	41,834	171,641		171,641
8	Operating Income	145,781	328,277	474,058	118,167	358,729	476,964	145,781	(32,587)	113,195	138,244	251,439	118,167	(33,618)	84,549	169,806	254,354
9	Federal and State Income Taxes	18,071	87,714	105,786	12,578	95,851	108,429	18,071	(8,839)	9,232	36,939	46,171	12,578	(8,983)	3,595	45,372	48,967
10	Net Income	127,710	240,563	368,272	105,589	262,878	368,535	127,710	(23,747)	103,962	101,305	205,268	105,589	(24,635)	80,953	124,434	205,387
11	Rate Base	5,817,888		5,817,888	5,820,953		5,820,953	5,817,887	(2,921)	5,814,966		5,814,966	5,820,953	(2,606)	5,818,347		5,818,347
12	Equity WACC	56.05%		56.05%	56.05%		56.05%	56.05%		42.00%		42.00%	56.05%		42.00%		42.00%
13	Debt WACC	43.95%		43.95%	43.95%		43.95%	43.95%		58.00%		58.00%	43.95%		58.00%		58.00%
14	Equity Cost	11.30%		11.30%	11.30%		11.30%	11.30%		8.40%		8.40%	11.30%		8.40%		8.40%
15	Debt Cost	5.08%		5.08%	5.08%		5.08%	5.08%		5.08%		5.08%	5.08%		5.08%		5.08%
16	WACC Equity - Pre Tax	6.33%		6.33%	6.33%		6.33%	6.33%		3.53%		3.53%	6.33%		3.53%		3.53%
17	WACC LTD	2.23%		2.23%	2.23%		2.23%	2.23%		2.95%		2.95%	2.23%		2.95%		2.95%
18	ROB	8.56%		8.56%	8.56%		8.56%	8.56%		6.48%		6.48%	8.56%		6.48%		6.48%
19	Utility Operating Income	498,011		498,011	498,274		498,274	498,011		376,810		376,810	498,274		377,029		377,029
				498,011			498,274					376,810					377,029
20	Actual Operating Income	257,449		498,011	235,396		498,274	257,449		275,504		376,809	235,396		252,595		377,028
21	Operating Income Deficiency	240,563		-	262,878		-	240,562		101,306		1	262,878		124,434		1
22	GRCF	1.4809913		1.4809913	1.4809913		1.4809913	1.4809913		1.4809913		1.4809913	1.4809913		1.4809913		1.4809913
23	Revenue Increase	356,271		-	389,320		-	356,271		150,033		1	389,320		184,286		1

* This calculation does not include corrections to the cash working capital addressed in the rebuttal testimony of PPL Witness Katelyn Arnold (PPL St. No. 13-R), or the correction to rate base addressed in the rebuttal testimony of PPL Witness Daniel Dane (PPL St. No. 6-R).

Operating Income
Recalculation of I&E Revenue Requirement Reflecting Discovery Updates
Year Ended June 30, 2027
(Thousands of Dollars)

Line No.	Description	AS FILED			AS UPDATED IN DISCOVERY			I&E CALCULATION FROM DIRECT TESTIMONY					I&E CALCULATION WITH UPDATES FROM DISCOVERY				
		Proforma at Present Rates	Rate Increase	Proforma at Proposed Rates	Proforma at Present Rates	Rate Increase	Proforma at Proposed Rates	Company Proforma at Present Rates	I&E Recommended Adjustments	I&E Proforma at Present Rates	Rate Increase	I&E Proforma at Proposed Rates	Company Proforma at Present Rates	I&E Recommended Adjustments	I&E Proforma at Present Rates	Rate Increase	I&E Proforma at Proposed Rates*
1	Operating Revenues	1,005,772	356,271	1,362,043	1,010,491	389,320	1,399,811	1,005,772		1,005,772	258,877	1,264,649	1,010,491		1,010,491	294,217	1,304,708
2	Operating Expenses																
3	Operation and Maintenance	431,937	6,974	438,911	431,129	7,621	438,750	431,937	(38,454)	393,483	5,068	398,551	431,129	(36,295)	394,834	5,760	400,593
4	Depreciation and Amortization Expense	289,596		289,596	324,180		324,180	289,596		289,596		289,596	324,180		324,180		324,180
5	Taxes Other Than Income	68,847	21,020	89,867	67,337	22,970	90,307	68,847	(2,368)	66,479	15,019	81,498	67,337	(2,368)	64,969	17,069	82,038
5	Total Operating Expenses	790,381	27,994	818,375	822,646	30,591	853,237	790,381	(40,822)	749,559	20,086	769,645	822,646	(38,663)	783,983	22,828	806,812
6	Other Operating Income	60,129	-	60,129	60,129	-	60,129	60,129		60,129	-	60,129	60,129		60,129	-	60,129
7	Interest on Long-Term Debt	129,739		129,739	129,807		129,739	129,739	3,365	133,104		133,104	129,807	3,370	133,177		133,177
8	Operating Income	145,781	328,277	474,058	118,167	358,729	476,964	145,781	37,457	183,238	238,791	422,029	118,167	35,293	153,460	271,389	424,849
9	Federal and State Income Taxes	18,071	87,714	105,786	12,578	95,851	108,429	18,071	10,008	28,080	63,805	91,885	12,578	9,430	22,008	72,515	94,523
10	Net Income	127,710	240,563	368,272	105,589	262,878	368,535	127,710	27,448	155,158	174,986	330,144	105,589	25,863	131,451	198,874	330,325
11	Rate Base	5,817,888		5,817,888	5,820,953		5,820,953	5,817,887	(5,477)	5,812,410		5,812,410	5,820,953	(5,353)	5,815,601		5,815,601
12	Equity WACC	56.05%		56.05%	56.05%		56.05%	56.05%		55.00%		55.00%	56.05%		55.00%		55.00%
13	Debt WACC	43.95%		43.95%	43.95%		43.95%	43.95%		45.00%		45.00%	43.95%		45.00%		45.00%
14	Equity Cost	11.30%		11.30%	11.30%		11.30%	11.30%		10.32%		10.32%	11.30%		10.32%		10.32%
15	Debt Cost	5.08%		5.08%	5.08%		5.08%	5.08%		5.08%		5.08%	5.08%		5.08%		5.08%
16	WACC Equity - Pre Tax	6.33%		6.33%	6.33%		6.33%	6.33%		5.68%		5.68%	6.33%		5.68%		5.68%
17	WACC LTD	2.23%		2.23%	2.23%		2.23%	2.23%		2.29%		2.29%	2.23%		2.29%		2.29%
18	RORB	8.56%		8.56%	8.56%		8.56%	8.56%		7.97%		7.97%	8.56%		7.97%		7.97%
19	Utility Operating Income	498,011		498,011	498,274		498,274	498,011		463,249		463,249	498,274		463,503		463,503
20	Actual Operating Income	257,449		498,011	235,396		498,274	257,449		288,262		463,249	235,396		264,629		463,503
21	Operating Income Deficiency	240,563		-	262,878		-	240,562		174,987		1	262,878		198,875		1
22	GRCF	1.4809913		1.4809913	1.4809913		1.4809913	1.4809913		1.4794093		1.4794093	1.4809913		1.4794093		1.4794093
23	Revenue Increase	356,271		-	389,320		-	356,271		258,877		1	389,320		294,217		2

* This calculation does not include the correction to the cash working capital addressed in the rebuttal testimony of PPL Witness Katelyn Arnold (PPL St. No. 13-R).

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
BICKEY RIMAL
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Cost of Service
 Revenue Allocation**

Dated: January 23, 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Bickey Rimal and my business address is 1300 19th Street NW, Suite 620, Washington, DC 20036.

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

A. I am employed by Concentric Energy Advisors, Inc. (“Concentric”) as a Vice President.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony on behalf of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”) that is identified as PPL Electric Statement No. 7. My direct testimony was accompanied by PPL Exhibit Nos. BR-1 and BR-2, which, collectively, consist of the allocated cost of service study (“ACOSS”) based on PPL Electric’s Pennsylvania jurisdictional costs and operating conditions for a fully projected future test year (“FPFTY”) ending June 30, 2027.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to issues raised by other parties related to the Company’s ACOSS, revenue allocation, and residential customer charge. My rebuttal testimony is limited to a discussion of certain issues raised by these witnesses, and the failure to address every issue in each statement submitted by witnesses for other parties

1 does not mean or imply that I or the Company agrees with the positions taken by such
2 parties with respect to those issues.

3
4 **Q. Are you sponsoring any exhibits to accompany your rebuttal testimony?**

5 A. Yes. I am sponsoring PPL Electric Exhibits BR-1R and BR-2R, which are discussed
6 further below. I am also providing the Company's response to OSBA-II-2 as PPL Electric
7 Exhibit BR-3R.

8
9 **Q. Would you briefly describe the contents of PPL Electric Exhibit Nos. BR-1R and BR-**
10 **2R?**

11 A. PPL Electric Exhibits BR-1R and BR-2R present the Company's revised ACOSS and
12 accompanying functionalization and classification studies, respectively. Like PPL Electric
13 Exhibit BR-1, PPL Electric Exhibit BR-1R: (1) is based on the Company's claimed costs
14 and operating conditions for the FPFTY ending June 30, 2027; (2) provides a summary of
15 the results, cost assignment, and allocation details of the study; and (3) includes the detailed
16 results of the ACOSS along with additional details about the methodology I employed.
17 Like PPL Exhibit BR-2, PPL Exhibit BR-2R provides the results of studies used to
18 functionalize and classify certain distribution plant of the Company based on plant data for
19 the historic test year ("HTY") ended June 30, 2025. The results of the functionalization
20 and classification studies were applied to the Company's distribution plant data for the
21 FPFTY. The Company is submitting PPL Electric Exhibit BR-1R and BR-2R to reflect
22 changes in various components of its revenue requirement that were identified after the

1 Company submitted its base rate increase request on September 30, 2025. The changes to
2 the revenue requirement are described in rebuttal testimony of Mr. Dane (PPL Electric St.
3 No. 6-R).

4
5 **II. ALLOCATED COST OF SERVICE STUDY**

6 **Q. Please briefly summarize the other parties' positions concerning the Company's**
7 **ACOSS.**

8 A. The following is a brief summary of the various parties' positions concerning the
9 Company's ACOSS:

- 10 • Bureau of Investigation and Enforcement ("I&E") Witness Ethan Cline observes that
11 the Company's ACOSS in this case employs the same methodology used in PPL
12 Electric's 2015 base rate case and recommends no adjustments to the Company's
13 ACOSS.¹
- 14 • Office of Consumer Advocate ("OCA") Witness Clarence Johnson proposes an
15 alternate approach to classifying certain distribution costs in lieu of the minimum
16 system study I used to identify a customer component of those distribution costs. Mr.
17 Johnson also proposes that primary distribution costs be classified as 100% demand.²
- 18 • Office of Small Business Advocate ("OSBA") Witness Mark D. Ewen did not prepare
19 his own ACOSS and relied on the Company's ACOSS "because the Company's

¹ I&E St. No. 4, p. 7.

² OCA St. 4, pp 3-4.

1 approach is consistent with the methodology that has been approved by the
2 Commission.”³

- 3 • Energy Justice Advocates (“EJA”) Witness Karl Rabago recommends that the
4 Commission reject the use of minimum system method to classify costs to be included
5 in the fixed customer charge for residential customers in this case; direct the Company
6 to use the “basic customer method” to classify costs to be included in the fixed customer
7 charge for residential customers in future rate cases; and direct the Company to include
8 in the customer charge only those costs that vary with the number of customers.⁴

- 9 • PPL Industrial Customer Alliance (“PPLICA”) Witness Billie S. LaConte states,
10 “PPL’s class cost-of-service study (CCOSS) generally comports with industry
11 practice” and “should be used to apportion any change in delivery revenues approved”
12 in this proceeding.⁵

- 13 • Walmart Inc. (“Walmart”) Witness Matthew T. Lyon states that “Walmart does not
14 take a position on the Company’s proposed COSS at this time.”⁶

15

³ OSBA St. No. 1, p. 3.

⁴ EJA St. No. 1, p. 6.

⁵ PPLICA St. No. 1, p. 2.

⁶ Walmart St. No. 1, p. 6.

1 **A. Classification of Poles, Conductors, and Line Transformers**

2 **Q. What are Mr. Johnson's and Mr. Rabago's views on the classification of poles,**
3 **conductors, and line transformers?**

4 A. Mr. Johnson's preferred position is to classify shared distribution facilities as 100%
5 demand. However, he also states that, considering PPL Electric's history of using the
6 minimum system to identify a customer component of poles, conductors, and line
7 transformers, he proposes an alternate approach using labor installation costs to classify
8 certain distribution costs in lieu of the minimum system study. Mr. Johnson also proposes
9 that primary distribution costs be classified as 100% demand.⁷ Mr. Rabago's
10 recommendations concerning the classification of the costs of poles, conductors, and line
11 transformers are tied to what he believes should be included in the residential customer
12 charge. While this may appear to be a rate design issue, it implicates the classification
13 methodology used in the ACROSS because it is based on Mr. Rabago's proposal that the
14 Commission reject the use of minimum system method to classify a portion of poles,
15 conductors, and line transformers as customer-related costs.⁸

16
17 **Q. Are the costs of certain distribution assets (distribution poles, conductors, and line**
18 **transformers) only related to demand?**

19 A. No. Such distribution system costs are incurred to move electricity from generation and
20 transmission facilities to individual customers who are distributed geographically

⁷ OCA St. 4, pp 3-4.

⁸ EJA St. No. 1, p. 6.

1 throughout PPL Electric's service territory. A significant portion of those costs are
2 incurred regardless of the peak demand of the customers. Increases or decreases in demand
3 do not result in proportionate increases or decreases in the number of poles and miles of
4 conductors and conduits required to distribute electricity geographically. For example, if
5 the load of customers in PPL Electric service territory were significantly reduced, but the
6 number of customers remained unchanged, we would not expect the number of poles and
7 miles of wires in the service territory to decrease by the same proportion. A portion of
8 distribution system costs are properly classified as customer-related because the
9 distribution system exists to deliver electricity to hundreds of thousands of customers who
10 are widely spread throughout the Company's service territory. Most of those costs are
11 totally unrelated to peak demand.

12
13 **Q. At page 48, lines 8-10 of EJA Statement No. 1, Mr. Rabago contends that "if the cost**
14 **remains after a customer leaves the system, the cost is not a customer cost." Based**
15 **on that erroneous assertion, he further contends that line transformers, secondary**
16 **and primary distribution lines do not have any customer-related component. Is it**
17 **accurate that all line transformers and secondary and primary distribution costs**
18 **related to poles and conductors are entirely demand-based costs?**

19 **A.** No. There are two fundamental problems with his assertion. First, simply because a
20 customer leaving the distribution system does not require an electric distribution company
21 to remove or reduce the number of line transformers, number of poles, or miles of
22 conductor does not mean that 100 percent of the cost of those facilities are, therefore,

1 entirely demand-related. Second, an addition or reduction in kilowatts of demand is not a
2 direct driver of an increase or decrease in the number of line transformers, number of poles,
3 or miles of conductor. This underscores the point that increases or decreases in demand do
4 not directly or proportionally affect the amount of distribution infrastructure required in an
5 electric distribution company's service territory. Therefore, it is unreasonable to assume
6 that the costs of line transformers, poles, and conductors are 100 percent demand-related.
7 The minimum system methodology recognizes that a portion of the distribution system is
8 customer-related and a portion is demand-related.

9
10 **Q. Is the classification of certain distribution plant as customer-related a recognized**
11 **electric utility practice?**

12 A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") *Electric*
13 *Utility Cost Allocation Manual* ("NARUC Manual") dedicates an entire chapter to the
14 classification and allocation of distribution plant (Chapter 6). As a part of that chapter, the
15 NARUC Manual identifies the minimum system methodology as one of the two methods
16 used to determine the demand-related and customer-related components of the distribution
17 system.⁹ The NARUC Manual states:

18 When the utility installs distribution plant to provide service to a customer
19 and to meet the individual customer's peak demand requirements, the
20 utility must classify *distribution plant data separately into demand- and*
21 *customer-related costs.*

⁹ The other method is the "zero-intercept" method.

1 Distribution plant Accounts 364 through 370 involve demand and
2 customer costs. The customer component of distribution facilities is that
3 portion of costs which varies with the number of customers. Thus, the
4 number of poles, conductors, transformers, services, and meters are
5 directly related to the number of customers on the utility's system.¹⁰

6
7 **Q. Is the classification of certain distribution plant as being partially customer-related**
8 **and partially demand-related a recognized practice in Pennsylvania?**

9 A. Yes. To my knowledge, all major electric distribution companies in Pennsylvania classify
10 a portion of their distribution plant as being both demand-related and customer-related.

11
12 **Q. Has the Commission ruled on the classification issue recently?**

13 A. Yes. In the most recent fully litigated electric case in Pennsylvania, the Commission ruled
14 on the classification issue and reaffirmed its decision to allow the usage of minimum
15 system to classify distribution costs and rejected OCA's arguments by stating:¹¹

16 We have reviewed the OCA's position and Exceptions on this issue and
17 are not persuaded by the arguments it presented in support of its
18 recommended alternative ACOSS methodology. As UGI and the OSBA
19 pointed out, the OCA has presented its alternative ACOSS methodology
20 in prior Commission proceedings and we have rejected it, including in our
21 *2012 PPL Order*. The record indicates that on all major issues, UGI's
22 ACOSS was performed in accordance with PPL's cost of service study
23 methodology in its 2012 rate case and approved in our *2012 PPL Order*.
24 The record also indicates that UGI's witness Mr. Taylor performed both
25 the PPL cost of service study in that proceeding and that of UGI in the
26 instant proceeding. UGI M.B. at 135. We conclude that the OCA has not
27 presented convincing arguments in this proceeding that would cause us to
28 re-evaluate our determination in our *2012 PPL Order*.

29

¹⁰ NARUC, Electric Utility Cost Allocation Manual, Chapter 6, at p. 90 (1992) (emphasis added).

¹¹ PA PUC, Opinion and Order issued 10/4/2018, Docket R-2017-2640058 et al., p. 160.

1 Additionally, as UGI and the OSBA both highlighted, the Commission has
2 affirmed the use of the “minimum system method” as the accepted
3 approach to classify and allocate distribution system costs in several
4 proceedings. *See 2012 PPL Order, supra; see also, Pa. PUC v. PPL*
5 *Electric Utilities Corp.*, Docket No. R-2010-2161694, (Order entered
6 December 21, 2010) (2010 PPL Order). Further, we find that UGI’s
7 ACOSS is consistent with the NARUC Manual and more accurately
8 reflects cost causation principles than the ACOSS methodology proposed
9 by the OCA. Accordingly, we shall deny the Exceptions of the OCA.

10 **Q. Is the methodology used in the ACOSS in this case consistent with PPL Electric’s 2012**
11 **and 2015 filings?**

12 A. Yes. The ACOSS methodology used in this case is consistent with PPL Electric’s 2012
13 and 2015 filings.

14
15 **B. PPL Electric’s Minimum System Study**

16 **Q. In OCA Statement 4, at page 13, Mr. Johnson states as follows regarding the**
17 **Company’s minimum system study: “The fictitious distribution system is comprised**
18 **of components which are not intended to carry load. Most such studies either identify**
19 **minimum size plant components or perform a statistical regression analysis to**
20 **determine the hypothetical cost of a system which has zero load carrying capability.”**
21 **Is the goal of the minimum system study to calculate the cost of a system that has zero**
22 **load carrying capability?**

23 A. No. Mr. Johnson is confusing a minimum system study with a zero-intercept study. A
24 minimum system study assumes that a minimally sized distribution system must exist to
25 connect all the customers within an electric distribution companies service territory and

1 serve the minimum requirements of those customers. Under the minimum system
2 approach, it is anticipated that the minimum sized components currently being installed by
3 an electric distribution company have some load carrying capacity. By contrast, a zero-
4 intercept study relates the installed costs of facilities to their current carrying capacity or
5 demand rating, creates a curve for various sizes of the equipment involved, and, using
6 regression analysis, extends the curve to an intercept point where load is zero – hence the
7 name “zero intercept.” I want to emphasize that I did not conduct a zero-intercept (no-
8 load) study. As the NARUC Manual states, a minimum level of load-carrying capacity is
9 acceptable under the minimum system study method.
10

11 **Q. At page 14 of his direct testimony, Mr. Johnson cites Dr. Bonbright’s statement that**
12 **“this ‘residual’ cost of the distribution system is not closely related to either demand**
13 **or customer factors.” Why does he then support the claim that these distribution**
14 **system costs should be classified as entirely demand-related?**

15 A. It is not clear to me why Mr. Johnson believes that these costs should be considered entirely
16 demand-related after reaching the conclusion that they are neither demand- nor customer-
17 related.
18

19 **Q. Did Dr. Bonbright have a preference between demand and customer allocation of**
20 **these costs?**

21 A. Yes. Following the paragraph of the Bonbright treatise that Mr. Johnson quotes on page 14
22 of his direct testimony, it goes on to state:

1 While, for the reason just suggested, the inclusion of the costs of a
2 minimum-sized distribution system among customer-related costs
3 seems to me clearly indefensible, *its exclusion from the demand-*
4 *related costs stands on much firmer ground.*¹²

5 Therefore, it is clear that if given the choice between including the minimum-sized
6 distribution costs as customer-related or demand-related, Dr. Bonbright's preference would
7 be to classify it as customer-related, as was done in the study I filed. Between the two
8 options, he indicates that treating minimum-sized distribution costs as demand-related is
9 an even worse outcome than including them as customer costs.

10
11 **Q. What are Mr. Johnson's primary concerns with the minimum system studies that you**
12 **conducted?**

13 A. At page 16, lines 12-16, Mr. Johnson claims that there are two issues with the minimum
14 system study. He states that "the Company has not utilized true minimum size components"
15 and "the load carrying capability of the minimum size components creates inequitable
16 double counting of demand-related costs."

17
18 **Q. Do you agree with his criticisms?**

19 A. No. I will address each of his issues below.

¹² Bonbright, James C., Principles of Public Utility Rates, Columbia University Press (1961), p. 348 (emphasis added).

1 **Q. What is Mr. Johnson’s specific criticism regarding the selection of the minimum size**
2 **components?**

3 A. At page 17, he claims that “[t]he Company’s study relies upon facility component sizes
4 which are larger than the minimum size installed on the system.” He then claims that
5 utilities choose minimum size components based upon a wide range of criteria.
6

7 **Q. Does Mr. Johnson’s concern regarding the choice of the minimum sized asset used in**
8 **the studies have any merit?**

9 A. No. The minimum size used in the minimum system studies are based on the guidance
10 provided by the NARUC Manual. According to the Manual, across all asset types (i.e.,
11 poles, conductors, and line transformers), the minimum-sized asset used in the analysis
12 should be the minimum-sized asset currently being installed. The hypothetical minimum
13 system was determined using the minimum-sized assets currently being installed by PPL
14 Electric based on the information provided by relevant personnel at the Company. For
15 example, minimum sized poles used in the study are the “minimum height pole currently
16 being installed” in accordance with the NARUC Manual.¹³ Similarly, the minimum sized
17 overhead and underground conductors used in study are “minimum size conductor
18 currently being installed” and “minimum size cable currently being installed,”
19 respectively.¹⁴ Finally, the minimum sized transformer used is the “minimum size

¹³ NARUC, Electric Utility Cost Allocation Manual, Chapter 6, at p. 91 (1992).

¹⁴ NARUC, Electric Utility Cost Allocation Manual, Chapter 6, at p. 91 (1992).

1 transformer currently being installed.”¹⁵ Therefore, the minimum size used in the
2 minimum system studies I conducted for the Company is based on, and follows, the
3 guidance provided by the NARUC Manual.
4

5 **Q. At page 19, Mr. Johnson claims that there is double counting of class demands**
6 **because the minimum size components selected by the Company have substantial**
7 **load-carrying capacity. Is his claim valid?**

8 A. No. First, I want to clarify that the only components of the minimum system that have any
9 load carrying capacity are conductors and line transformers because poles and conduits do
10 not transmit any electricity. As explained earlier, some level of load is permissible under
11 the minimum system approach in contrast to the zero-intercept study. Even though the
12 minimum sized conductor and line transformers have some load carrying capacity,
13 virtually all customers impose some minimal load on the system and, for that reason, the
14 minimum system costs should be treated as providing equal benefit to all customers on the
15 relevant distribution system.
16

¹⁵ NARUC, Electric Utility Cost Allocation Manual, Chapter 6, at p. 91 (1992).

1 **Q. Does Mr. Johnson propose an alternate methodology to calculate the customer**
2 **component to correct the purported double-counting of demand in the minimum**
3 **system?**

4 A. Yes. At page 22, he claims that “[a] reasonable approach is to limit the cost of minimum
5 size components to the labor installation cost.” He then cites a 1985 rate case for Duquesne
6 Light as the purported basis for contending that the Commission has previously adopted
7 this methodology.

8
9 **Q. Is estimating the customer component using only the labor cost of the minimum**
10 **system a common method to calculating the customer component of distribution**
11 **assets?**

12 A. No. Using only the labor cost of the minimum system is not a common method to calculate
13 the customer component of the distribution assets. As I described earlier, the minimum
14 system method is one of the two methods described by the NARUC Manual to calculate
15 the customer component. The other method is the zero-intercept method.

16
17 **Q. Do you know what methodology Duquesne Light now uses to calculate the customer**
18 **portion of distribution plant?**

19 A. Yes. Duquesne Light used the minimum system study in its most recent rate filing. It no
20 longer relies solely on the “labor” portion of installed costs to calculate the customer
21 component. As a matter of fact, Duquesne Light has been using the minimum system study,

1 including plant and labor costs, to classify distribution costs between customer and demand
2 since as early as 2006.

3
4 **C. Customer-Related Costs**

5 **Q. Did Mr. Johnson and Mr. Rabago calculate a purported cost-based customer charge?**

6 A. Yes. At pages 35-36 of his direct testimony, Mr. Johnson claims that he calculated a cost-
7 based customer charge using the “basic customer method.” At page 35, lines 16-20, he
8 states that his cost-based customer charge includes “O&M expense for (1) meters, meter
9 reading, and customer accounting; (2) return, income tax and depreciation on meter and
10 service investment and (3) minus credits for customer deposits, late payment fees and
11 reconnection revenues and related deferred federal income tax components.” His customer
12 charge calculations exclude overhead and general expenses and uncollectible expenses. At
13 page 36, he calculates a customer charge of \$8.54 based on his analysis, but, on page 38,
14 he recommends that the Company’s residential customer charge should be maintained at
15 the current level. Similarly, at page 63, lines 12-15, Mr. Rabago calculated a purportedly
16 cost-based customer charge of \$10.20 and states:

17 To make this calculation I remove Primary and Secondary
18 Distribution costs, as well as transformer costs for the customer cost
19 category. I keep Deposits and Advances, Services, Meters, and
20 Meter Reading costs in the customer cost category. These true
21 customer costs constitute about 17% of the total costs that PPL
22 Electric classifies as customer costs, so I use that factor to assign
23 17% of customer service and billing and collection costs to the
24 customer cost category.
25

1 **Q. Do Mr. Johnson's and Mr. Rabago's calculations accurately capture the customer-**
2 **related costs?**

3 A. No. Both Mr. Johnson and Mr. Rabago are using a very restrictive and flawed description
4 of what constitutes customer-related cost. For example, Mr. Johnson excludes uncollectible
5 expenses as well as general and overhead expenses tied to customer costs. Mr. Rabago's
6 definition is similarly restrictive and only includes 17% of Customer Service, Billing, and
7 Collection costs. In addition, both witnesses' definition of customer-related cost also
8 excludes the customer portion of the distribution system. As explained previously, it is
9 appropriate to use the results of the minimum system study to estimate the portion of PPL
10 Electric's distribution costs that are customer-related. A portion of the costs related to the
11 distribution lines, poles, conduit and line transformers is unrelated to the amount of demand
12 because there is a bare minimum amount of costs that must be incurred simply to provide
13 access and attach a customer to the system. These minimum system costs are fixed and do
14 not vary by either the amount of demand placed on the system or the amount of energy
15 consumed.

16
17 **Q. Should the customer charge calculations exclude overhead and general expenses as**
18 **recommended by Mr. Johnson?**

19 A. No. The portion of these costs contained in overhead and general expense and uncollectible
20 expense and classified as being customer-related should be part of the customer charge
21 calculations. Even under the strict basic customer method, the indirect costs assigned to
22 the customer classification should be included as part of the basic customer cost. The

1 indirect costs associated with a particular function (for example, metering) are part of the
2 cost of providing service to the customers associated with those functions. In a hypothetical
3 scenario, if there were a utility that only provided metering services and nothing else, then
4 the indirect costs of such a utility are part of providing metering services to the customer
5 and accordingly should be considered a metering-related cost. One of the outcomes of
6 conducting a fully allocated cost of service study is to determine the full cost of providing
7 service by each function, and that full cost should include both direct and indirect costs.
8

9 **Q. Mr. Rabago recommends excluding a significant portion (almost 87%) of Customer**
10 **Service and Billing and Collection costs from the customer charge calculations. Can**
11 **you please explain what type of costs are associated with these functions?**

12 A. Yes. The primary FERC accounts included within these functions are 903 - Customer
13 records and collection expenses, 904 - Uncollectible accounts, and 908 - Customer
14 assistance expenses.
15

16 **Q. Should customer charge calculations exclude 83% of Customer Service and Billing**
17 **and Collection costs as suggested by Mr. Rabago?**

18 A. No. These are customer-related costs that are classified as being customer-related costs
19 within the ACOSS and should be part of any customer charge calculations. Under the
20 FERC's Uniform System of Accounts ("USOA"), the costs are properly within the
21 categories of "Customer Accounts Expense" and "Customer Service and Informational
22 Expenses."

1
2 **Q. Is it appropriate to classify uncollectible expenses as customer-related and include**
3 **them as part of the customer charge?**

4 A. Yes. Similar to billing and collections costs, uncollectible expenses are properly within the
5 category of “Customer Accounts Expense” under the USOA.
6

7 **Q. Did any other party take issue with the determination of the customer-related costs?**

8 A. Yes. Mr. Cicero states “PPL witness Rimal appears to include a significant number of costs
9 as customer-related, which are likely not appropriate to be included in a fixed customer
10 charge because they do not actually vary directly with the number of customers.”¹⁶
11

12 **Q. Does his claim have any merit?**

13 A. No, they do not. As discussed earlier, the costs that are classified as customer-related
14 within the ACOSS are based on cost causation and, therefore, are properly classified.
15

16 **Q. Is the Company proposing to recover all customer-related costs in the proposed**
17 **customer charge?**

18 A. No, it is not. As discussed in more detail in PPL Electric witness Steven Wishart’s
19 testimony (PPL Electric St. No. 8-R), the Company is proposing to recover only a portion
20 of the customer-related costs in the customer charges for Rate Schedule RS. In fact, the

¹⁶ CAUSE-PA Statement No. 1, p. 28.

proposed customer charge is lower than the customer-related costs even if the customer-related cost classified using the minimum system method were excluded. The table below shows that the customer-related cost is about \$22.27 after excluding the customer-related cost classified using the minimum system study. This cost is still lower than what the Company is proposing.

Table 1: Residential Cost-Based Customer Cost

Function	ACOSS Customer Cost	Customer Cost Excluding Distribution Facilities	Distribution Facilities
Deposits and Advances	(\$79,430)	(\$79,430)	\$0
Distribution Primary	\$243,606,765		\$243,606,765
Distribution Secondary	\$74,020,639		\$74,020,639
Line Transformers	\$23,457,328		\$23,457,328
Services	\$69,595,772	\$69,595,772	\$0
Meters	\$35,953,868	\$35,953,868	\$0
Lighting	\$0	\$0	\$0
Meter Reading	\$8,942,520	\$8,942,520	\$0
Customer Service	\$94,596,811	\$94,596,811	\$0
Billing and Collections	\$138,468,000	\$138,468,000	\$0
Total Customer-Related Costs	\$688,562,274	\$347,477,541	\$341,084,732
Annual Bills (Customer Count * 12)	15,603,324	15,603,324	\$15,603,324
Unit Costs (\$/Bill)	\$44.13	\$22.27	\$21.86

III. REVENUE ALLOCATION

Q. Please summarize the position of the parties as it relates to revenue allocation.

A. The following is a brief summary of the various parties' positions concerning revenue allocation.

- 1 • Mr. Cline agrees with the Company's revenue allocation and points out that the
2 Company's proposal moves each rate class towards the relative rate of return of
3 1.0.¹⁷
- 4 • Mr. Johnson agrees with Company's revenue allocation methodology.¹⁸
- 5 • Mr. Ewen states that the Company's revenue allocation is directionally consistent
6 with the results of the ACROSS, but he recommends assigning a slightly higher rate
7 increase to the RS class and a corresponding lower increase to the GS-1 class.¹⁹
- 8 • Ms. LaConte recommends lowering the cap on the increase to any class to 1.3 times
9 the system average increase to prevent substantial increases to the RTS and LP-4
10 classes.²⁰
- 11 • Mr. Lyon states that "Walmart does not oppose the Company's revenue allocation
12 proposal at this time."²¹ However, he also states that, in the event the Commission
13 approves a lower revenue requirement, he proposes a mechanism to re-distribute
14 the reduction among the various classes.

15 **Q. What is Mr. Johnson's position on the revenue allocation method you proposed?**

16 A. Mr. Johnson agrees with the methodology used for revenue allocation. At page 28 of his
17 direct testimony, Mr. Johnson states "[w]hile a number of different mitigation methods are
18 within the range of reasonableness, in my view the two constraints (150% cap and no
19 revenue decrease) proposed by Mr. Rimal are reasonable and consistent with the most
20 commonly used gradualism benchmarks."
21

¹⁷ I&E Statement No. 4, p. 9.

¹⁸ OCA Statement 4, p. 28.

¹⁹ OSBA Statement No. 1, p. 11.

²⁰ PPLICA Statement No. 1, p. 2-3.

²¹ Walmart Statement No. 1, p. 6.

1 **Q. What is Mr. Ewen's recommendation?**

2 A. As previously discussed, Mr. Ewen acknowledges that the Company's revenue allocation
3 is directionally consistent with the results of the ACROSS, but he recommends assigning a
4 slightly higher rate increase to RS class and a correspondingly lower increase for the GS-
5 1 class.

6
7 **Q. How do you respond to his recommendation?**

8 A. Even though moving classes closer to their cost of service is a desired outcome, the
9 Company's proposed revenue allocation is reasonable considering the principle of
10 gradualism. Also, it is not clear what "slightly higher" would mean in terms of dollars
11 movement in revenue allocation. The services allocator correction described below actually
12 results in shifting revenue requirements from residential classes to some of the general
13 service classes (GS-1, GS-3, and GH-2).

14
15 **Q. Do you agree with Ms. LaConte's recommendation to lower the increase cap to 1.3**
16 **times the system average increase to prevent substantial increases to the RTS and LP-**
17 **4 classes?**

18 A. No. As explained in my direct testimony, the main goal of the 1.5 times cap coupled with
19 no reduction to any rate class was to reduce the inter-class subsidies and move classes
20 closer to their cost of service, while ensuring the impact on any one particular class is
21 moderated. In my view, lowering the cap to 1.3 times the system average increase does not
22 reduce the inter-class subsidies between the classes sufficiently and, therefore, the

1 Company should continue to adhere to a cap on any class increase of 1.5 times the system
2 average. In addition, since the RTS class is being eliminated and rolled into the RS class,
3 the final increase for the RTS class is lower than the 1.5 times cap.
4

5 **Q. What is Walmart's position on Company's proposed revenue allocation?**

6 A. Mr. Lyon states that "Walmart does not oppose the Company's revenue allocation
7 proposal at this time."²² However, he also proposes that, if the Commission approves a
8 lower revenue requirement, the "Commission should allocate 50 percent of the overall
9 revenue reduction to the rate classes currently below their cost of service levels, ensuring
10 that no class receives an increase that exceeds their cost of service levels. The remaining
11 50 percent of the overall revenue reduction should be evenly applied to mitigate the
12 proposed increases for all rate classes on an equal percentage basis."
13

14 **Q. Do you agree with his proposal?**

15 A. No. First, it is not proper to speculate about the possibility that the Commission may
16 authorize a lower increase than the Company has supported in this case. Accordingly, it is
17 premature to try to set parameters to guide a different allocation than the one the Company
18 has proposed. Second, even if the Commission were to approve less than the Company's
19 requested increase, there is not, at this point, any objective standard to determine whether

²² Walmart Statement No. 1, p. 6.

1 Walmart's proposal would ensure that no class receives an increase exceeding its cost of
2 service.

3 **IV. UNBUNDLING OF COSTS**

4 **Q. What is Mr. Lacey's proposal regarding unbundling of costs?**

5 A. Mr. Lacey recommends that the Commission direct the Company to "conduct an exercise
6 to unbundle all of PPL Electric's costs to serve customers and to allocate those costs
7 appropriately to default service and distribution-only customers to facilitate a much more
8 fair and competitive electricity market."²³

9
10 **Q. Do you believe that the Company should be required to "conduct an exercise" to**
11 **further "unbundle" costs in order to "allocate" those costs between default service**
12 **and distribution service differently than they are currently allocated?**

13 A. No. The distribution revenue requirement in this proceeding is not related to providing
14 supply services and, therefore, there are no costs to "unbundle" and allocate differently
15 between default service and distribution service. The costs the Company incurs to furnish
16 distribution service will continue to be incurred whether or not there are any default service
17 customers.

18

²³ RESA St. No. 1, pp. 4-5.

1 **Q. Has the Commission ruled on this issue recently?**

2 A. Yes. NRG Energy (“NRG”) made a similar proposal in PECO Energy Company’s
3 (“PECO”) 2018 base rate case proceeding. In that case, the Commission rejected NRG’s
4 proposal stating:²⁴

5 We find that NRG has presented no persuasive or compelling evidence
6 demonstrating that the current allocations are unfair, or that its proposed
7 re-allocations are a more equitable result than PECO’s proposed rates.
8 Therefore, we shall deny Exceptions Nos. 1 through 4 submitted by NRG
9 and adopt the ALJs’ recommendation.

10
11 On January 18, 2019, NRG filed a Petition for Review of the Commission’s decision with
12 the Commonwealth Court of Pennsylvania. The Commonwealth Court affirmed the
13 Commission’s decision and stated:²⁵

14 The Competition Act was intended to help consumers by creating a more
15 competitive electric market through the unbundling of the three functions
16 of the market. However, the Competition Act also created a safety net, a
17 DSP [default service plan], to provide electricity for distribution
18 customers should they choose not to shop for generation services or should
19 an EGS fail to provide service. While we acknowledge NRG’s desire to
20 promote what it believes would be a fairer market that would enhance
21 competition, the Commission was not persuaded by NRG’s evidence and
22 arguments. Therefore, we affirm the Commission’s Opinion and Order for
23 the reasons stated above.

24
25 **Q. Who is responding to the other issues raised by Mr. Lacey?**

26 A. PPL Electric Witness Lisa Norden is responding to other issues raised by Mr. Lacey.

²⁴ Pennsylvania Public Utility Commission v. PECO Energy Company (2018, December 20). *Opinion and Order* (Docket No. R-2018-3000164), p. 74.

²⁵ *NRG Energy, Inc. v. Pa. PUC*, Pa. Cmwlth. Ct., No. 58 C.D. 2019, decided June 2, 2020.

V. REBUTTAL UPDATES

Q. Are you making any update to the ACOSS with the rebuttal filing?

A. Yes. An error was made in applying the allocation factor used to allocate the cost related to service wires to the various classes. This error was identified in a discovery request from OSBA (OSBA II-2), and the Company's response is attached as PPL Electric Exhibit BR-3R. A summary of the updated results of the ACOSS reflecting the correction of the application error and the relative rates of return produced by each class for the FPFTY by the revised ACOSS are presented in PPL Electric Exhibit BR-1R (p. 7, line 23).

Rate Class	Rate Code	Return at Current Rates	Relative Rate of Return
Residential	RS	4.02%	1.0
Residential-Thermal Storage	RTS	1.96%	0.5
Small General Service - Sec. Voltage	GS-1	3.23%	0.8
Large General Service - Sec. Voltage	GS-3	4.85%	1.2
Large General Service - 12 KV	LP-4	3.28%	0.8
Large General Service - 69 KV or Higher	LP-5	24.13%	5.9
Separate Meter General Space Heating Service	GH-2	3.90%	1.0
Street Lighting/Area Lighting	SL/AL	5.81%	1.4
Total System		4.07%	1.0

Q. Please describe the results of your rebuttal ACOSS.

A. The table below summarizes the revenues at present rates, revenues based on the revised ACOSS, and the proposed mitigated revenue requirement by rate class based on the rebuttal ACOSS. The rebuttal ACOSS incorporates the updated rebuttal revenue requirement as well as the correction to the services allocator.

Table 2: Revenues at Present and Proposed Rates

Rate Class	Rate Code	Revenue at Current Rates	Revenue Requirement based on ACOSS	Mitigated Revenue Requirement	ACOSS Increase (%)	Mitigated Increase (%)
Residential	RS	\$723,510,477	\$988,838,995	\$992,172,528	36.67%	37.13%
Residential-Thermal Storage	RTS	\$7,981,752	\$13,655,830	\$12,455,443	71.09%	56.05%
Small General Service - Sec. Voltage	GS-1	\$78,914,440	\$113,706,094	\$113,938,983	44.09%	44.38%
Large General Service - Sec. Voltage	GS-3	\$129,383,893	\$176,201,362	\$176,811,578	36.18%	36.66%
Large General Service - 12 KV	LP-4	\$39,043,210	\$64,707,084	\$60,926,532	65.73%	56.05%
Large General Service - 69 KV or Higher	LP-5	\$1,989,146	\$1,361,088	\$1,989,146	-31.57%	0.00%
Separate Meter General Space Heating Service	GH-2	\$1,308,731	\$1,853,864	\$1,858,438	41.65%	42.00%
Street Lighting/Area Lighting	SL/AL	\$24,457,815	\$30,786,347	\$30,958,018	25.88%	26.58%
Total System		\$1,006,589,465	\$1,391,110,665	\$1,391,110,665	38.20%	38.20%

VI. SUMMARY AND CONCLUSIONS

Q. Please describe your summary and conclusions.

A. A number of intervening parties and their witnesses have disputed various aspects of the ACOSS and revenue allocation proposed by PPL Electric in this proceeding. However, a number of witnesses for intervenors also support various aspects of the Company's ACOSS and revenue allocation. Most of the changes proposed by the witnesses for intervenors involve shifting costs from the group of PPL Electric customers they view as their constituency to another group of PPL Electric customers that they do not view as their constituency. As discussed throughout this testimony, in my opinion most of the proposed changes to the filed ACOSS and revenue allocation are without merit and as a result, I continue to believe that PPL Electric's proposed ACOSS and revenue allocation are based

on cost causation. I have listed below my specific conclusions and recommendations reflecting my positions in my direct and rebuttal testimony:

- The Commission should accept the results of the Company's ACROSS provided in rebuttal as reasonable since it is based on cost causation and continues to employ the methodology previously approved by the Commission.
- The Commission should continue to accept the classification of certain distribution assets (poles, conductors, and line transformers) as being both customer-related and demand-related and reject any claims to classify these distribution assets as being solely demand-related, since increases or decreases in demand do not result in proportionate increases or decreases in the number of poles and miles of conductors and conduits required to distribute electricity geographically.
- The Commission should accept the revenue allocation and mitigation measures proposed by the Company because they reduce the inter-class subsidies and move classes closer to their cost of service, while ensuring that the impact on any one particular class is moderated.
- The Commission should approve the customer charge proposed by the Company.

Q. Does this conclude your prepared rebuttal testimony?

A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION
PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
JURISDICTIONAL AND RETAIL COST ALLOCATION STUDIES
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027
Witness: Bickey Rimal**

Docket No. R-2025-3057164

PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027
COST ALLOCATION STUDY - INDEX

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**PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027**

SECTION I

PREFACE

Cost allocation studies are submitted in support of the direct testimony of Bickey Rimal and in response to Question IV-E-1 of Exhibit Regs. § 53.53, Part IV-Rate Structure and Cost Allocation, regarding a fully distributed Cost-of-Service study. Exhibit BR 1 presents results for the fully projected future test year ending June 30, 2027. The Commission's Order at Docket No. R-80031114 provided that PPL Electric's Historical retail rate filings should be on a Pennsylvania jurisdictional basis only.

The study contained herein provides the assignment/allocation of system costs between the Federal and Pennsylvania jurisdictions, and the allocation of the Pennsylvania jurisdictional costs to retail customer rate schedule classes. This preface explains the general methodology utilized in the preparation of PPL Electric's study.

Total cost of providing service, broadly stated, is made up of the following generally recognized and accepted components:

1. Operation and maintenance expenses.
2. Depreciation and amortization expenses associated with the investment in utility facilities.
3. Taxes, including income taxes.
4. Return on net investment in utility facilities, materials and supplies, and other working capital requirements, collectively called measures of value or rate base.

Through a cost allocation study, total Company costs are allocated to residential, commercial, industrial, and other customer classes or groups. Comparing the costs to serve any customer group with that group's rate revenues provides a measure of the return realized from that group. Relating that realized return to the allocated rate base for the group results in the rate of return (expressed as a percentage), which can be compared with the system average rate of return and the rates of return realized from other classes of customers. This allows for a comparison across classes to determine the presence and extent of subsidization (i.e., when one class pays more than the cost to serve them and another pays less than their share of costs).

Overall costs of providing service are allocated to groups of customers on the basis of their distinctive service characteristics. One main service characteristic is the voltage level at which the electric service is rendered. PPL Electric's investment in utility property and the applicable operating costs must be broken down and reassembled into the following functional voltage level component categories:

1. High voltage transmission facilities which are necessary to serve all customer classes;
2. Transmission system (500 kV, 230 kV, 138 kV and 69 kV) facilities from which large power customers (Rate Schedules LP-5) and certain resale customers are directly served, and which also are necessary to serve all other classes at lower voltages;
3. Primary system (23 kV and 12 kV) facilities from which large general service customers (Rate Schedule LP-4) and certain other resale customers are directly served, and which are necessary to serve other classes at lower voltages, but are not required to serve customers at transmission voltage levels; and
4. Secondary distribution system, encompassing the remainder of the system, from which street lighting, general service, commercial space heating, and residential customers are served, but which is not required to serve customers served at higher voltage levels.

PPL Electric's records are kept in accordance with the Federal Energy Regulatory Commission's Uniform System of Accounts ("FERC Accounts"), which has been adopted by this Commission. The FERC Accounts does not identify the costs in precisely the functional category groupings required for cost allocation purposes for all functions. Thus, a rearrangement of book data is required. Major examples of the steps in this process, which are detailed in Exhibit BR-2, are:

1. Separation of distribution facilities between the primary and secondary voltages, and the classification of the customer-related and demand-related components of primary and secondary facilities' investment; and
2. Assignment of operation and maintenance expenses to categories based generally on plant investment assignments.

After reassembling the costs into the appropriate functional components, each customer group is allocated its share of the investment and operating costs of the applicable functional categories. The four basic classification criteria for determining the share of component costs chargeable to particular customer groups are:

1. Relative demand responsibility. A major factor governing the assignment of plant investment is the necessity to provide distribution capacity sufficient to be able to reliably meet the combined demands of all PPL Electric's customers. Investment and other costs considered demand-related are allocated on the basis of the pro rata demand responsibilities of the classes.
2. Customer costs. A substantial portion of system costs is not related to the amount of service provided. Meter investment and meter reading costs are customer-related, as are customer service and customer accounting costs. In addition, a

portion of a utility's investment in poles, line transformers, conductors, etc., must be made irrespective of the customer's demand, or simply because the customer is there to be served. Costs considered customer-related are allocated on the basis of either the number of customers or the weighted number of customers in each class.

3. Direct assignment. In a few cases, the FERC System of Accounts makes a specific identification of costs which permits assignment directly to the rate class or customer group responsible for those costs. An example is the direct assignment of street lighting-related costs to the street lighting customer group.

PPL Electric's primary (12 kV) and secondary voltage level demand -related costs are allocated based on a class's maximum annual non-coincident peak demand. This approach recognizes that distribution facilities are sized to meet local area peaks.

Two steps are required in the assignment/allocation process. The total electric system costs are allocated or directly assigned between FERC jurisdictional customers and Pennsylvania retail service customers. The Pennsylvania jurisdictional values are further allocated among the retail customer classes and related to the present and proposed revenues from those classes to determine the class rates of return on rate base.

PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027

SECTION II
COST ALLOCATION TO PENNSYLVANIA RETAIL SERVICE CUSTOMERS

SUMMARY OF RESULTS

The summaries contained in this section present the results of the detailed allocations of Pennsylvania jurisdictional costs at present and proposed rates for the fully projected future test period. The summaries consist of an array of customer class income statements and the relationships of class operating incomes (or returns) to the respective allocated measures of value or rate base. The relationship of each class rate of return to the total Pennsylvania jurisdictional rate of return is also presented.

PPL Electric views these relationships to be useful because one of the objectives of ratemaking is to have each class producing a rate of return as close to the overall system average rate of return as appropriate. The second part provides details regarding the mitigation approach implemented to limit large increases to certain classes.

The third part provides details by FERC account including taxes and pro forma adjustments for each of these jurisdictions. This section is organized by several sections as listed: Net Plant, Depreciation, Rate Base Adjustments, O&M, Labor (for development of labor allocator), Depreciation Expense, Amortization, Taxes, and Revenues. Further, the account balances that are inputs to this section are directly from the PUC Jurisdiction Distribution columns within the Jurisdictional model as provided in Section III.

The functionalization, classification, and allocation that support the results provided in this section are detailed in Section IV.

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line			Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Rate Base									
1	Plant in Service	\$ 10,201,986,912	\$ 6,949,122,208	\$ 103,637,354	\$ 825,137,052	\$ 1,460,760,608	\$ 553,503,765	\$ 9,340,417	\$ 14,258,762	\$ 286,226,745
2	Accumulated Reserve	3,256,079,387	2,243,137,989	31,256,509	279,717,944	437,970,730	149,842,411	5,174,018	4,565,875	104,413,912
3	Other Rate Base Items	(1,125,118,376)	(760,099,222)	(11,427,762)	(91,633,282)	(165,423,261)	(61,906,774)	(1,028,711)	(1,585,846)	(32,013,518)
4	Total Rate Base	\$ 5,820,789,148	\$ 3,945,884,998	\$ 60,953,083	\$ 453,785,827	\$ 857,366,617	\$ 341,754,581	\$ 3,137,688	\$ 8,107,041	\$ 149,799,315
	Revenues at Current Rates									
5	Distribution	1,006,589,465	723,510,477	7,981,752	78,914,440	129,383,893	39,043,210	1,989,146	1,308,731	24,457,815
6	Late Payment Charges	15,305,520	11,428,698	83,895	1,363,531	1,785,597	542,576	81,961	19,262	-
7	Annualization	4,932,874	3,865,736	(91,936)	20,269	891,225	221,023	8,188	(5,140)	23,509
8	Other Operating Revenue	43,792,776	29,267,020	457,947	3,481,796	6,609,045	2,536,864	33,626	62,388	1,344,091
9	Total Revenues	\$ 1,070,620,634	\$ 768,071,931	\$ 8,431,657	\$ 83,780,037	\$ 138,669,760	\$ 42,343,673	\$ 2,112,921	\$ 1,385,241	\$ 25,825,415
	Expenses at Current Rates									
10	Operations & Maintenance Expenses	430,799,486	326,272,418	3,816,787	36,737,101	43,109,394	14,351,802	238,420	514,014	5,759,549
11	Fuel and Purchased Power	323,299	109,363	1,777	14,232	63,371	45,253	88,467	271	565
12	Amortization Expense	-	-	-	-	-	-	-	-	-
13	Depreciation Expenses	324,155,908	229,966,874	3,093,648	27,482,008	40,502,945	13,580,987	719,042	451,693	8,358,711
14	Total Operations & Maintenance Expenses	\$ 755,278,692	\$ 556,348,655	\$ 6,912,211	\$ 64,233,342	\$ 83,675,709	\$ 27,978,042	\$ 1,045,929	\$ 965,979	\$ 14,118,825
	Taxes									
15	Income Taxes	\$ (33,261,000)	\$ (25,243,640)	\$ (775,567)	\$ (4,340,276)	\$ (1,080,916)	\$ (2,196,480)	\$ 209,500	\$ (47,339)	\$ 213,719
16	Deferred Income Taxes	46,470,000	33,528,527	446,026	3,933,897	5,459,496	1,972,833	41,090	60,974	1,027,156
17	Investment Tax Credit	(15,000)	(10,058)	(155)	(1,198)	(2,249)	(860)	(14)	(21)	(444)
18	Taxes Other Than Income Taxes (excl. GRT)	8,822,000	6,453,680	83,446	755,103	980,070	348,641	7,732	11,388	181,941
19	Gross Receipts Tax	56,151,000	38,247,467	570,413	4,541,495	8,039,921	3,046,445	51,409	78,479	1,575,371
20	Total Taxes	\$ 78,167,000	\$ 52,975,976	\$ 324,162	\$ 4,889,020	\$ 13,396,322	\$ 3,170,578	\$ 309,718	\$ 103,481	\$ 2,997,743
21	Current Operating Expenses	833,445,693	609,324,632	7,236,374	69,122,362	97,072,031	31,148,620	1,355,647	1,069,461	17,116,568
22	Current Operating Income	237,174,941	158,747,299	1,195,284	14,657,675	41,597,729	11,195,053	757,274	315,780	8,708,847
23	Return at Current Rates	4.07%	4.02%	1.96%	3.23%	4.85%	3.28%	24.13%	3.90%	5.81%
24	Index Rate of Return		0.99	0.48	0.79	1.19	0.80	5.92	0.96	1.43

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line			Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	<u>INCOME TAX CALCCS</u>									
	<u>Income Tax Calculations</u>									
25	Operating Revenue	\$ 1,070,620,634	\$ 768,071,931	\$ 8,431,657	\$ 83,780,037	\$ 138,669,760	\$ 42,343,673	\$ 2,112,921	\$ 1,385,241	\$ 25,825,415
26	Operating Expense	755,278,692	556,348,655	6,912,211	64,233,342	83,675,709	27,978,042	1,045,929	965,979	14,118,825
27	Gross Receipts Tax	56,151,000	38,247,467	570,413	4,541,495	8,039,921	3,046,445	51,409	78,479	1,575,371
28	Taxes Other Than Income Taxes (excl GRT)	8,822,000	6,453,680	83,446	755,103	980,070	348,641	7,732	11,388	181,941
29	Taxable Income Before Adjustments	250,368,942	167,022,128	865,588	14,250,098	45,974,060	10,970,545	1,007,851	329,394	9,949,278
30	Interest Expense	(129,803,598)	(87,993,235)	(1,359,254)	(10,119,424)	(19,119,276)	(7,621,127)	(69,970)	(180,787)	(3,340,525)
31	Other Adjustment to Taxable Income	(234,334,000)	(166,143,512)	(2,302,765)	(19,490,463)	(29,409,987)	(11,042,734)	(132,576)	(310,450)	(5,501,513)
32	Adjustment to Taxable Income	(364,137,598)	(254,136,747)	(3,662,019)	(29,609,886)	(48,529,263)	(18,663,861)	(202,547)	(491,237)	(8,842,037)
33	Taxable Net Income	<u>\$ (113,768,656)</u>	<u>\$ (87,114,619)</u>	<u>\$ (2,796,431)</u>	<u>\$ (15,359,788)</u>	<u>\$ (2,555,203)</u>	<u>\$ (7,693,316)</u>	<u>\$ 805,304</u>	<u>\$ (161,843)</u>	<u>\$ 1,107,241</u>
	<u>PA Income Tax Calculations</u>									
34	Total Taxable Net Income	\$ (113,768,656)	\$ (87,114,619)	\$ (2,796,431)	\$ (15,359,788)	\$ (2,555,203)	\$ (7,693,316)	\$ 805,304	\$ (161,843)	\$ 1,107,241
35	PA Special Deduction	(34,238,000)	(23,783,936)	(332,323)	(2,863,636)	(4,598,524)	(1,555,517)	(85,018)	(49,145)	(969,900)
36	PA Taxable Net Income	<u>(148,006,656)</u>	<u>(110,898,555)</u>	<u>(3,128,755)</u>	<u>(18,223,425)</u>	<u>(7,153,727)</u>	<u>(9,248,833)</u>	<u>720,286</u>	<u>(210,989)</u>	<u>137,340</u>
37	PA Income Tax	<u>\$ (10,720,990)</u>	<u>\$ (8,033,032)</u>	<u>\$ (226,634)</u>	<u>\$ (1,320,029)</u>	<u>\$ (518,186)</u>	<u>\$ (669,947)</u>	<u>\$ 52,175</u>	<u>\$ (15,283)</u>	<u>\$ 9,948</u>
	<u>Federal Income Tax Calculations</u>									
38	Total Taxable Net Income	\$ (113,768,656)	\$ (87,114,619)	\$ (2,796,431)	\$ (15,359,788)	\$ (2,555,203)	\$ (7,693,316)	\$ 805,304	\$ (161,843)	\$ 1,107,241
39	Deduction - PA Income Tax	10,720,990	8,033,032	226,634	1,320,029	518,186	669,947	(52,175)	15,283	(9,948)
40	Federal Taxable Net Income before NOL	(103,047,667)	(79,081,587)	(2,569,797)	(14,039,759)	(2,037,017)	(7,023,369)	753,130	(146,560)	1,097,292
41	Federal Net Operating Loss	-	-	-	-	-	-	-	-	-
42	Federal Taxable Net Income after NOL	(103,047,667)	(79,081,587)	(2,569,797)	(14,039,759)	(2,037,017)	(7,023,369)	753,130	(146,560)	1,097,292
43	Federal Income Tax @ 21.00%	(21,640,010)	(16,607,133)	(539,657)	(2,948,349)	(427,774)	(1,474,907)	158,157	(30,778)	230,431
44	Federal Tax Credit	(900,000)	(603,475)	(9,275)	(71,898)	(134,956)	(51,626)	(831)	(1,278)	(26,661)
45	Federal Income Tax	<u>\$ (22,540,010)</u>	<u>\$ (17,210,608)</u>	<u>\$ (548,933)</u>	<u>\$ (3,020,247)</u>	<u>\$ (562,729)</u>	<u>\$ (1,526,533)</u>	<u>\$ 157,326</u>	<u>\$ (32,056)</u>	<u>\$ 203,770</u>
46	Total Tax	<u>\$ (33,261,000)</u>	<u>\$ (25,243,640)</u>	<u>\$ (775,567)</u>	<u>\$ (4,340,276)</u>	<u>\$ (1,080,916)</u>	<u>\$ (2,196,480)</u>	<u>\$ 209,500</u>	<u>\$ (47,339)</u>	<u>\$ 213,719</u>

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line			Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Revenue Requirement at Equal Rates of Return at Proposed Rates										
47	Required Return	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%
48	Required Operating Income	\$ 498,259,551	\$ 337,767,756	\$ 5,217,584	\$ 38,844,067	\$ 73,390,582	\$ 29,254,192	\$ 268,586	\$ 693,963	\$ 12,822,821
49	Operating Income (Deficiency)/Surplus	\$ (261,084,610)	\$ (179,020,457)	\$ (4,022,300)	\$ (24,186,391)	\$ (31,792,854)	\$ (18,059,139)	\$ 488,688	\$ (378,183)	\$ (4,113,974)
Expenses at Equal Rate of Return at Proposed Rates										
Operations & Maintenance Expenses										
50	Distribution	438,331,644	332,870,826	3,848,192	37,065,070	43,542,989	14,458,259	240,799	516,888	5,788,621
51	Fuel and Purchased Power	323,299	109,363	1,777	14,232	63,371	45,253	88,467	271	565
52	Amortization Expense	-	-	-	-	-	-	-	-	-
53	Depreciation Expense	324,155,908	229,966,874	3,093,648	27,482,008	40,502,945	13,580,987	719,042	451,693	8,358,711
54	Total Operations & Maintenance Expenses	\$ 762,810,850	\$ 562,947,063	\$ 6,943,617	\$ 64,561,310	\$ 84,109,305	\$ 28,084,499	\$ 1,048,308	\$ 968,853	\$ 14,147,897
Taxes										
55	Income Taxes	61,936,030	40,472,461	626,501	4,276,147	10,500,077	4,146,378	56,336	87,560	1,770,570
56	DIT+ITC	46,455,000	33,518,469	445,871	3,932,699	5,457,247	1,971,972	41,076	60,953	1,026,712
57	Taxes Other Than Income Taxes	8,822,001	6,249,364	(18,658)	540,129	1,460,713	71,916	64,155	10,954	443,428
58	Gross Receipts Tax	78,557,452	53,714,024	900,133	6,568,703	10,767,522	4,538,821	15,500	110,229	1,942,519
59	Total Taxes	\$ 195,770,483	\$ 133,954,318	\$ 1,953,848	\$ 15,317,678	\$ 28,185,559	\$ 10,729,087	\$ 177,068	\$ 269,696	\$ 5,183,229
60	Proposed Operating Expenses	\$ 958,581,333	\$ 696,901,381	\$ 8,897,464	\$ 79,878,988	\$ 112,294,863	\$ 38,813,586	\$ 1,225,375	\$ 1,238,549	\$ 19,331,126
61	Proposed Operating Income	\$ 498,259,551	\$ 337,767,756	\$ 5,217,584	\$ 38,844,067	\$ 73,390,582	\$ 29,254,192	\$ 268,586	\$ 693,963	\$ 12,822,821
62	Total Proposed Revenue Requirement at Equal Rate	\$ 1,456,840,884	\$ 1,034,669,137	\$ 14,115,048	\$ 118,723,055	\$ 185,685,446	\$ 68,067,778	\$ 1,493,961	\$ 1,932,511	\$ 32,153,948
63	Revenue Increase	\$ 386,220,250	\$ 266,597,207	\$ 5,683,391	\$ 34,943,018	\$ 47,015,686	\$ 25,724,105	\$ (618,960)	\$ 547,271	\$ 6,328,532
64	Less Late Payment Revenue	\$ 17,004,570	\$ 12,697,386	\$ 93,208	\$ 1,514,896	\$ 1,983,814	\$ 602,807	\$ 91,060	\$ 21,400	\$ -
65	Less Annualization	4,932,874	3,865,736	(91,936)	20,269	891,225	221,023	8,188	(5,140)	23,509
66	Less Other Revenues	43,792,776	29,267,020	457,947	3,481,796	6,609,045	2,536,864	33,626	62,388	1,344,091
67	Total Base Rate Revenues as Proposed	\$ 1,391,110,665	\$ 988,838,995	\$ 13,655,830	\$ 113,706,094	\$ 176,201,362	\$ 64,707,084	\$ 1,361,088	\$ 1,853,864	\$ 30,786,347
INCREASE IN INCOME TAX AND GRT @ EQUAL RATES										
68	Revenue Increase at Proposed	386,220,250	266,597,207	5,683,391	34,943,018	47,015,686	25,724,105	(618,960)	547,271	6,328,532
69	Less Late Payment Increase	1,699,050	1,268,688	9,313	151,364	198,217	60,231	9,098	2,138	-
70	Revenue Increase at Proposed Base Rates	384,521,200	265,328,518	5,674,078	34,791,653	46,817,469	25,663,875	(628,058)	545,132	6,328,532
71	Less - Provision for Uncollectible Expense @ 1.67%	6,421,504	4,430,986	94,757	581,021	781,852	428,587	(10,489)	9,104	105,686
72	Gross Receipts Tax @ 5.90%	22,406,452	15,466,557	329,720	2,027,209	2,727,601	1,492,376	(35,909)	31,750	367,148
73	Commission Fees	1,110,654	752,489	11,574	87,213	163,545	64,546	666	1,550	29,072
74	Taxable Income for PA Corporate Tax	356,281,641	245,947,174	5,247,340	32,247,576	43,342,689	23,738,597	(573,228)	504,867	5,826,626
75	PA Income Tax @ 7.24%	25,794,791	17,806,575	379,907	2,334,724	3,138,011	1,718,674	(41,502)	36,552	421,848
76	Taxable Income for Federal Income Tax	330,486,850	228,140,599	4,867,433	29,912,851	40,204,678	22,019,922	(531,727)	468,315	5,404,778
77	Federal Income Tax @ 21.00%	69,402,238	47,909,526	1,022,161	6,281,699	8,442,982	4,624,184	(111,663)	98,346	1,135,003
78	Federal and State Tax Relating to Increase	\$ 95,197,029	\$ 65,716,101	\$ 1,402,068	\$ 8,616,423	\$ 11,580,993	\$ 6,342,858	\$ (153,164)	\$ 134,899	\$ 1,556,851

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line			Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Mitigation										
79	Proposed Increase Post Apportionment	\$ 384,521,200	\$ 268,662,051	\$ 4,473,691	\$ 35,024,542	\$ 47,427,684	\$ 21,883,322	\$ -	\$ 549,706	\$ 6,500,203
Revenue Requirement at Proposed Mitigated Rates										
80	Total Base Rate Revenues as Proposed	\$ 1,391,110,665	\$ 992,172,528	\$ 12,455,443	\$ 113,938,983	\$ 176,811,578	\$ 60,926,532	\$ 1,989,146	\$ 1,858,438	\$ 30,958,018
81	Other Revenues	65,730,220	45,830,142	459,218	5,016,961	9,484,084	3,360,694	132,873	78,648	1,367,600
82	Total Revenues as Proposed	\$ 1,456,840,884	\$ 1,038,002,670	\$ 12,914,661	\$ 118,955,944	\$ 186,295,661	\$ 64,287,226	\$ 2,122,019	\$ 1,937,085	\$ 32,325,618
83	Expenses (Excl. Taxes)	\$ 762,810,850	\$ 562,947,063	\$ 6,943,617	\$ 64,561,310	\$ 84,109,305	\$ 28,084,499	\$ 1,048,308	\$ 968,853	\$ 14,147,897
Taxes										
84	Income Taxes	61,713,987	41,114,663	329,414	4,310,626	10,633,506	3,208,601	209,500	88,436	1,819,239
85	Taxes Other Than Income Taxes	54,996,702	39,383,329	492,986	4,433,588	6,847,327	2,245,149	69,323	71,225	1,453,776
86	Gross Receipts Tax	78,837,751	54,098,528	834,360	6,607,943	10,838,154	4,337,561	51,409	110,912	1,958,883
87	Total Taxes	\$ 195,548,440	\$ 134,596,521	\$ 1,656,761	\$ 15,352,157	\$ 28,318,988	\$ 9,791,310	\$ 330,232	\$ 270,573	\$ 5,231,898
88	Operating Income as Proposed	\$ 498,481,594	\$ 340,459,086	\$ 4,314,284	\$ 39,042,476	\$ 73,867,369	\$ 26,411,417	\$ 743,480	\$ 697,660	\$ 12,945,822
89	Return at Proposed Rates	8.56%	8.63%	7.08%	8.60%	8.62%	7.73%	23.70%	8.61%	8.64%
90	Index Rate of Return		1.01	0.83	1.00	1.01	0.90	2.77	1.00	1.01
INCREASE IN INCOME TAX AND GRT @ PROPOSED RATES										
91	Revenue Increase at Proposed	\$ 384,521,200	\$ 268,662,051	\$ 4,473,691	\$ 35,024,542	\$ 47,427,684	\$ 21,883,322	\$ -	\$ 549,706	\$ 6,500,203
92	Less - Provision for Uncollectible Expense @ 1.67%	\$ 6,421,504	\$ 4,486,656	\$ 74,711	\$ 584,910	\$ 792,042	\$ 365,451	\$ -	\$ 9,180	\$ 108,553
93	Gross Receipts Tax @ 5.90%	\$ 22,686,751	\$ 15,851,061	\$ 263,948	\$ 2,066,448	\$ 2,798,233	\$ 1,291,116	\$ -	\$ 32,433	\$ 383,512
94	PA Capital Stock Tax	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
95	Taxable Income for PA Corporate Tax	\$ 355,412,945	\$ 248,324,334	\$ 4,135,033	\$ 32,373,185	\$ 43,837,409	\$ 20,226,755	\$ -	\$ 508,093	\$ 6,008,137
96	PA Income Tax @ 7.24%	\$ 25,744,643	\$ 17,987,587	\$ 299,525	\$ 2,344,979	\$ 3,175,400	\$ 1,465,142	\$ -	\$ 36,804	\$ 435,205
97	Taxable Income for Federal Income Tax	\$ 329,668,302	\$ 230,336,747	\$ 3,835,508	\$ 30,028,205	\$ 40,662,008	\$ 18,761,612	\$ -	\$ 471,289	\$ 5,572,933
98	Federal Income Tax @ 21.00%	\$ 69,230,343	\$ 48,370,717	\$ 805,457	\$ 6,305,923	\$ 8,539,022	\$ 3,939,939	\$ -	\$ 98,971	\$ 1,170,316
99	Federal and State Tax Relating to Increase	\$ 94,974,986	\$ 66,358,304	\$ 1,104,981	\$ 8,650,903	\$ 11,714,422	\$ 5,405,081	\$ -	\$ 135,775	\$ 1,605,520

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line			Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
<u>Functional Revenue Requirement at Equal Rate of Rrn</u>										
Deposits and Advances										
100	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
101	Customer	\$ (273,393)	\$ (81,925)	\$ (517)	\$ (63,220)	\$ (120,510)	\$ (4,628)	\$ -	\$ (605)	\$ (1,987)
102	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
103	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
106	<i>Sub-total</i>	\$ (273,393)	\$ (81,925)	\$ (517)	\$ (63,220)	\$ (120,510)	\$ (4,628)	\$ -	\$ (605)	\$ (1,987)
Distribution Primary										
107	Demand	\$ 434,276,387	\$ 233,108,901	\$ 5,682,689	\$ 24,212,474	\$ 105,043,810	\$ 64,470,285	\$ -	\$ 717,241	\$ 1,040,987
108	Customer	\$ 290,623,693	\$ 251,258,501	\$ 2,246,879	\$ 28,395,772	\$ 7,840,687	\$ 244,517	\$ -	\$ 287,291	\$ 350,048
109	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
110	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
111	<i>Sub-total</i>	\$ 724,900,081	\$ 484,367,402	\$ 7,929,568	\$ 52,608,246	\$ 112,884,497	\$ 64,714,802	\$ -	\$ 1,004,532	\$ 1,391,034
Distribution Secondary										
112	Demand	\$ 97,215,128	\$ 61,279,983	\$ 1,493,873	\$ 6,365,008	\$ 27,614,059	\$ -	\$ -	\$ 188,549	\$ 273,656
113	Customer	\$ 88,232,576	\$ 76,345,642	\$ 682,721	\$ 8,628,140	\$ 2,382,416	\$ -	\$ -	\$ 87,294	\$ 106,363
114	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
115	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
116	<i>Sub-total</i>	\$ 185,447,704	\$ 137,625,625	\$ 2,176,594	\$ 14,993,148	\$ 29,996,475	\$ -	\$ -	\$ 275,844	\$ 380,019
Line Transformers										
117	Demand	\$ 47,561,722	\$ 29,980,740	\$ 730,865	\$ 3,114,029	\$ 13,509,957	\$ -	\$ -	\$ 92,246	\$ 133,884
118	Customer	\$ 27,961,127	\$ 24,194,128	\$ 216,356	\$ 2,734,279	\$ 754,994	\$ -	\$ -	\$ 27,664	\$ 33,707
119	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
120	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
121	<i>Sub-total</i>	\$ 75,522,849	\$ 54,174,868	\$ 947,221	\$ 5,848,308	\$ 14,264,951	\$ -	\$ -	\$ 119,910	\$ 167,591

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line				Residential	Residential- Thermal Storage	Small General Service	Large General Service	Large General Service	Large General Service	Large General Service	Separate Meter	Street Lighting/Area
						Sec. Voltage	- Sec. Voltage	- 12 KV	- 69 KV or Higher	General Space Heating Service		Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL		
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)		
Services												
122	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
123	Customer	\$ 95,136,944	\$ 71,781,788	\$ 641,909	\$ 12,807,546	\$ 9,776,122	\$ -	\$ -	\$ 129,579	\$ -	\$ -	-
124	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
125	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
126	Sub-total	\$ 95,136,944	\$ 71,781,788	\$ 641,909	\$ 12,807,546	\$ 9,776,122	\$ -	\$ -	\$ 129,579	\$ -	\$ -	-
Meters												
127	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
128	Customer	\$ 59,042,644	\$ 37,083,186	\$ 371,515	\$ 6,714,189	\$ 10,501,030	\$ 2,856,462	\$ 1,368,041	\$ 148,221	\$ -	\$ -	-
129	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
130	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
131	Sub-total	\$ 59,042,644	\$ 37,083,186	\$ 371,515	\$ 6,714,189	\$ 10,501,030	\$ 2,856,462	\$ 1,368,041	\$ 148,221	\$ -	\$ -	-
Lighting												
132	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
133	Customer	\$ 29,928,458	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	29,928,458
134	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
135	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
136	Sub-total	\$ 29,928,458	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	29,928,458
Meter Reading												
137	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
138	Customer	\$ 10,656,786	\$ 9,223,407	\$ 82,480	\$ 1,042,376	\$ 287,822	\$ 8,976	\$ 1,179	\$ 10,546	\$ -	\$ -	-
139	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
140	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
141	Sub-total	\$ 10,656,786	\$ 9,223,407	\$ 82,480	\$ 1,042,376	\$ 287,822	\$ 8,976	\$ 1,179	\$ 10,546	\$ -	\$ -	-
Customer Service												
142	Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
143	Customer	\$ 111,716,837	\$ 97,568,116	\$ 761,748	\$ 9,585,659	\$ 3,361,909	\$ 222,356	\$ 15,787	\$ 93,228	\$ 108,034	\$ -	-
144	Fuel	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
145	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	-
146	Sub-total	\$ 111,716,837	\$ 97,568,116	\$ 761,748	\$ 9,585,659	\$ 3,361,909	\$ 222,356	\$ 15,787	\$ 93,228	\$ 108,034	\$ -	-

[illegible]

Line				Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	
Functional Revenue Requirement (Classification bynction)											
Demand											
164	Deposits and Advances	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
165	Distribution Primary	\$ 434,276,387	\$ 233,108,901	\$ 5,682,689	\$ 24,212,474	\$ 105,043,810	\$ 64,470,285	\$ -	\$ 717,241	\$ 1,040,987	
166	Distribution Secondary	\$ 97,215,128	\$ 61,279,983	\$ 1,493,873	\$ 6,365,008	\$ 27,614,059	\$ -	\$ -	\$ 188,549	\$ 273,656	
167	Line Transformers	\$ 47,561,722	\$ 29,980,740	\$ 730,865	\$ 3,114,029	\$ 13,509,957	\$ -	\$ -	\$ 92,246	\$ 133,884	
168	Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
169	Meters	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
170	Lighting	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
171	Meter Reading	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
172	Customer Service	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
173	Billing and Collections	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
174	Purchased Power	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
175	Sub-total	\$ 579,053,238	\$ 324,369,625	\$ 7,907,428	\$ 33,691,511	\$ 146,167,826	\$ 64,470,285	\$ -	\$ 998,037	\$ 1,448,526	
176	Zero-Check	-	-	-	-	-	-	-	-	-	
Customer											
177	Deposits and Advances	\$ (273,393)	\$ (81,925)	\$ (517)	\$ (63,220)	\$ (120,510)	\$ (4,628)	\$ -	\$ (605)	\$ (1,987)	
178	Distribution Primary	\$ 290,623,693	\$ 251,258,501	\$ 2,246,879	\$ 28,395,772	\$ 7,840,687	\$ 244,517	\$ -	\$ 287,291	\$ 350,048	
179	Distribution Secondary	\$ 88,232,576	\$ 76,345,642	\$ 682,721	\$ 8,628,140	\$ 2,382,416	\$ -	\$ -	\$ 87,294	\$ 106,363	
180	Line Transformers	\$ 27,961,127	\$ 24,194,128	\$ 216,356	\$ 2,734,279	\$ 754,994	\$ -	\$ -	\$ 27,664	\$ 33,707	
181	Services	\$ 95,136,944	\$ 71,781,788	\$ 641,909	\$ 12,807,546	\$ 9,776,122	\$ -	\$ -	\$ 129,579	\$ -	
182	Meters	\$ 59,042,644	\$ 37,083,186	\$ 371,515	\$ 6,714,189	\$ 10,501,030	\$ 2,856,462	\$ 1,368,041	\$ 148,221	\$ -	
183	Lighting	\$ 29,928,458	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 29,928,458	
184	Meter Reading	\$ 10,656,786	\$ 9,223,407	\$ 82,480	\$ 1,042,376	\$ 287,822	\$ 8,976	\$ 1,179	\$ 10,546	\$ -	
185	Customer Service	\$ 111,716,837	\$ 97,568,116	\$ 761,748	\$ 9,585,659	\$ 3,361,909	\$ 222,356	\$ 15,787	\$ 93,228	\$ 108,034	
186	Billing and Collections	\$ 164,438,675	\$ 142,817,307	\$ 1,202,754	\$ 15,172,571	\$ 4,669,780	\$ 224,558	\$ 20,487	\$ 150,985	\$ 180,233	
187	Purchased Power	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
188	Sub-total	\$ 877,464,348	\$ 710,190,149	\$ 6,205,844	\$ 85,017,311	\$ 39,454,249	\$ 3,552,240	\$ 1,405,495	\$ 934,203	\$ 30,704,856	
189	Zero-Check	-	-	-	-	-	-	-	-	-	
Fuel											
190	Deposits and Advances	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
191	Distribution Primary	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
192	Distribution Secondary	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
193	Line Transformers	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
194	Services	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
195	Meters	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
196	Lighting	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
197	Meter Reading	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
198	Customer Service	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
199	Billing and Collections	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
200	Purchased Power	\$ 323,299	\$ 109,363	\$ 1,777	\$ 14,232	\$ 63,371	\$ 45,253	\$ 88,467	\$ 271	\$ 565	
201	Sub-total	\$ 323,299	\$ 109,363	\$ 1,777	\$ 14,232	\$ 63,371	\$ 45,253	\$ 88,467	\$ 271	\$ 565	
202	Zero-Check	-	-	-	-	-	-	-	-	-	
Total Revenue Requirement											
203	Demand	\$ 579,053,238	\$ 324,369,625	\$ 7,907,428	\$ 33,691,511	\$ 146,167,826	\$ 64,470,285	\$ -	\$ 998,037	\$ 1,448,526	
204	Customer	\$ 877,464,348	\$ 710,190,149	\$ 6,205,844	\$ 85,017,311	\$ 39,454,249	\$ 3,552,240	\$ 1,405,495	\$ 934,203	\$ 30,704,856	
205	Fuel	\$ 323,299	\$ 109,363	\$ 1,777	\$ 14,232	\$ 63,371	\$ 45,253	\$ 88,467	\$ 271	\$ 565	
206	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
207	Total	\$ 1,456,840,884	\$ 1,034,669,137	\$ 14,115,048	\$ 118,723,055	\$ 185,685,446	\$ 68,067,778	\$ 1,493,961	\$ 1,932,511	\$ 32,153,948	
	Zero-Check	-	-	-	-	-	-	-	-	-	

**Allocated Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line			Residential	Residential- Thermal Storage	Small General Service Sec. Voltage	Large General Service - Sec. Voltage	Large General Service - 12 KV	Large General Service - 69 KV or Higher	Separate Meter General Space Heating Service	Street Lighting/Area Lighting
No.	Description	System Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)

Adjusted Revenue Requirement (Excluding Late Payment Reve and Annualization)

208	Ratio of Base Revenue to Total Revenue	95.49%	95.57%	96.75%	95.77%	94.89%	95.06%	91.11%	95.93%	95.75%
209	Total Base Revenue Requirement									
210	Demand	\$ 552,253,484	\$ 310,001,838	\$ 7,650,168	\$ 32,267,786	\$ 138,702,147	\$ 61,287,210	\$ -	\$ 957,419	\$ 1,386,916
211	Customer	\$ 838,552,760	\$ 678,732,639	\$ 6,003,943	\$ 81,424,677	\$ 37,439,081	\$ 3,376,856	\$ 1,280,490	\$ 896,184	\$ 29,398,890
212	Fuel	\$ 304,421	\$ 104,519	\$ 1,719	\$ 13,631	\$ 60,134	\$ 43,018	\$ 80,598	\$ 260	\$ 541
213	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
213	Total	\$ 1,391,110,665	\$ 988,838,995	\$ 13,655,830	\$ 113,706,094	\$ 176,201,362	\$ 64,707,084	\$ 1,361,088	\$ 1,853,864	\$ 30,786,347

Mitigated Revenue Requirement (Excluding Late Payment Reve and Annualization)

214	Ratio of Apportioned Base Revenue to Total Base Revenue	100.00%	100.34%	91.21%	100.20%	100.35%	94.16%	146.14%	100.25%	100.56%
215	Total Base Revenue Requirement									
216	Demand	\$ 549,601,868	\$ 311,046,903	\$ 6,977,696	\$ 32,333,875	\$ 139,182,496	\$ 57,706,466	\$ -	\$ 959,782	\$ 1,394,650
217	Customer	\$ 841,169,257	\$ 681,020,754	\$ 5,476,179	\$ 81,591,448	\$ 37,568,739	\$ 3,179,561	\$ 1,871,357	\$ 898,395	\$ 29,562,824
218	Fuel	\$ 339,540	\$ 104,871	\$ 1,568	\$ 13,659	\$ 60,343	\$ 40,505	\$ 117,789	\$ 261	\$ 544
219	Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
220	Total	\$ 1,391,110,665	\$ 992,172,528	\$ 12,455,443	\$ 113,938,983	\$ 176,811,578	\$ 60,926,532	\$ 1,989,146	\$ 1,858,438	\$ 30,958,018
		TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
221	Units									
222	Bills	18,045,181	15,603,324	138,767	1,769,083	478,071	14,840	1,993	17,726	21,377
223	Billing Demand (kW)	48,977,538	0	0	9,138,797	25,219,929	14,316,117	70,926	231,768	0
223	kWh	42,775,651,426	14,215,929,792	230,938,030	1,850,048,292	8,237,505,852	6,032,075,326	12,100,437,658	35,291,555	73,424,921
224	Unit Cost									
225	Customer Cost (\$/Bill)	\$ 63.58	\$ 89.75	\$ 46.12	\$ 78.58	\$ 214.26	\$ 938.83	\$ 50.68	\$ 1,448.14	
226	Demand Cost (\$/kW)	\$ -	\$ -	\$ 3.54	\$ 5.52	\$ 4.03	\$ -	\$ 4.14	\$ -	
226	Energy Cost (\$/kWh)	\$ 0.000007	\$ 0.000007	\$ 0.000007	\$ 0.000007	\$ 0.000007	\$ 0.000007	\$ 0.000010	\$ 0.000007	\$ 0.000007

For non-demand billed customers, demand cost is shown under \$/Bill

Revenue Allocation

227		Residential	Small C&I	Large Primary C&I	Large Transmission C&I	
228	Revenue Requirement	\$ 1,004,627,971	\$ 323,567,016	60,926,532	\$ 1,989,146	\$ 1,391,110,665
229	Allocation (%)	72.22%	23.26%	4.38%	0.14%	

**Allocated Cost of Service Study
Revenue Allocation (Mitigation)
Fully Projected Future Test Year**

57.30%	
1.5	Times System Increase (CAP)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Ln No.	Class		Current Base Rate Revenue	Proposed Base Rate Revenue at Equal Rates of Return	ACOSS Proposed Increase (Decrease) @ 8.56% ROR	ACOSS Rate Increase	Max if Increase capped at 1.5x System Increase	Classes Over Cap	Classes Under Cap
1	System Total	System Total	\$ 1,006,589,465	\$1,391,110,665	\$ 384,521,200	38.20%			
2	Residential	RS	\$ 723,510,477	\$ 988,838,995	\$ 265,328,518	36.67%	\$ 414,575,842	\$ -	\$ 149,247,324
3	Residential-Thermal Storage	RTS	7,981,752	13,655,830	5,674,078	71.09%	4,573,592	(1,100,486)	-
4	Small General Service - Sec. Voltage	GS-1	78,914,440	113,706,094	34,791,653	44.09%	45,218,448	-	10,426,794
5	Large General Service - Sec. Voltage	GS-3	129,383,893	176,201,362	46,817,469	36.18%	74,137,747	-	27,320,278
6	Large General Service - 12 KV	LP-4	39,043,210	64,707,084	25,663,875	65.73%	22,371,993	(3,291,881)	-
7	Large General Service - 69 KV or Higher	LP-5	1,989,146	1,361,088	(628,058)	-31.57%	1,139,793	-	1,767,851
8	Separate Meter General Space Heating Service	GH-2	1,308,731	1,853,864	545,132	41.65%	749,911	-	204,778
9	Street Lighting/Area Lighting	SL/AL	24,457,815	30,786,347	6,328,532	25.88%	14,014,475	-	7,685,942
10							Total	\$ (4,392,367)	\$ 196,652,967

Mitigation Rules

- 1) Increase to any class capped at 1.5x System Increase
- 2) No Rate Reduction to any class

**Allocated Cost of Service Study
Revenue Allocation (Mitigation)
Fully Projected Future Test Year**

	(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
Ln No.	Class		Mitigation	Interim Revised Increase (Decrease)	Classes Under Cap	Additional Mitigation	Proposed Increase (Decrease) - Post Mitigation	Rate Increase @ Proposed Rates	Proposed Mitigated Revenue	ROR @ Proposed Increase	Revenue to Cost Ratio	Final % Increase Minus ACOSS % Increase
1	System Total	System Total					\$ 384,521,200	38.20%	\$1,391,110,665	8.56%	1.00	0.00%
2	Residential	RS	\$(3,333,533)	\$ 268,662,051	\$145,913,791		\$ 268,662,051	37.13%	\$ 992,172,528	8.63%	1.00	0.46%
3	Residential-Thermal Storage	RTS	1,100,486	4,573,592	-	99,901	4,473,691	56.05%	12,455,443	7.08%	0.91	-15.04%
4	Small General Service - Sec. Voltage	GS-1	(232,889)	35,024,542	10,193,905		35,024,542	44.38%	113,938,983	8.60%	1.00	0.30%
5	Large General Service - Sec. Voltage	GS-3	(610,216)	47,427,684	26,710,063		47,427,684	36.66%	176,811,578	8.62%	1.00	0.47%
6	Large General Service - 12 KV	LP-4	3,291,881	22,371,993	-	488,671	21,883,322	56.05%	60,926,532	7.73%	0.94	-9.68%
7	Large General Service - 69 KV or Higher	LP-5	(39,486)	(588,572)	1,728,365	(588,572)	-	0.00%	1,989,146	23.70%	1.46	31.57%
8	Separate Meter General Space Heating Service	GH-2	(4,574)	549,706	200,205		549,706	42.00%	1,858,438	8.61%	1.00	0.35%
9	Street Lighting/Area Lighting	SL/AL	(171,670)	6,500,203	7,514,272		6,500,203	26.58%	30,958,018	8.64%	1.01	0.70%
10			\$ 0	\$ 384,521,200		\$ 0						

Mitigation Rules

- 1) Increase to any class capped at 1.5x System Increase
- 2) No Rate Reduction to any class

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No. / Projected Future Post Year		Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
RATE BASE														
Plant-in Service														
301-303	Intangible Plant													
	INTANGIBLE PLANT - DISTRIBUTION	670,295	LABOR	87,110	430,750	-	-	517,860	2,112	3,846	-	-	5,958	
	Sub-total	670,295		87,110	430,750	-	-	517,860	2,112	3,846	-	-	5,958	
Distribution Plant														
360	LAND AND LAND RIGHTS	113,493,096	DPLT	31,910,256	44,190,000	-	-	76,100,256	773,636	396,036	-	-	1,169,672	
361	STRUCTURES & IMPROVEMENTS	63,727,935	PRI_DEM	34,473,304	-	-	-	34,473,304	835,775	-	-	-	835,775	
362	STATION EQUIPMENT	1,071,977,540	PRI_DEM	579,880,819	-	-	-	579,880,819	14,058,698	-	-	-	14,058,698	
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	485,807,532	LABOR	63,134,472	312,193,392	-	-	375,327,864	1,530,640	2,787,639	-	-	4,318,278	
364	POLES TOWERS & FIXTURES - PRI - DEMAND	537,975,079	PRI_DEM	291,014,893	-	-	-	291,014,893	7,055,399	-	-	-	7,055,399	
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	840,388,740	PRI_CUST	-	726,748,375	-	-	726,748,375	-	6,463,299	-	-	6,463,299	
364	POLES TOWERS & FIXTURES - SEC - DEMAND	100,896,363	SEC_DEM	63,925,839	-	-	-	63,925,839	1,549,826	-	-	-	1,549,826	
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	402,471,412	SEC_CUST	-	348,334,278	-	-	348,334,278	-	3,097,893	-	-	3,097,893	
365	OVERHEAD CONDUCTORS - PRI - DEMAND	764,864,095	PRI_DEM	413,749,357	-	-	-	413,749,357	10,030,988	-	-	-	10,030,988	
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	628,932,106	PRI_CUST	-	543,885,662	-	-	543,885,662	-	4,837,019	-	-	4,837,019	
365	OVERHEAD CONDUCTORS - SEC - DEMAND	436,593,319	SEC_DEM	276,616,452	-	-	-	276,616,452	6,706,322	-	-	-	6,706,322	
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	116,846,029	SEC_CUST	-	101,128,865	-	-	101,128,865	-	899,384	-	-	899,384	
366	UNDERGROUND CONDUIT - PRI - DEMAND	244,979,109	PRI_DEM	132,520,208	-	-	-	132,520,208	3,212,835	-	-	-	3,212,835	
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	116,349,939	PRI_CUST	-	100,616,685	-	-	100,616,685	-	894,829	-	-	894,829	
366	UNDERGROUND CONDUIT - SEC - DEMAND	11,950,350	SEC_DEM	7,571,493	-	-	-	7,571,493	183,564	-	-	-	183,564	
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	4,614,402	SEC_CUST	-	3,993,711	-	-	3,993,711	-	35,518	-	-	35,518	
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	644,919,075	PRI_DEM	348,865,706	-	-	-	348,865,706	8,457,941	-	-	-	8,457,941	
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	306,296,709	PRI_CUST	-	264,878,174	-	-	264,878,174	-	2,355,680	-	-	2,355,680	
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	31,459,861	SEC_DEM	19,932,314	-	-	-	19,932,314	483,241	-	-	-	483,241	
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	12,147,632	SEC_CUST	-	10,513,633	-	-	10,513,633	-	93,502	-	-	93,502	
368	LINE TRANSFORMERS - DEMAND	483,261,279	SEC_DEM	306,184,302	-	-	-	306,184,302	7,423,168	-	-	-	7,423,168	
368	LINE TRANSFORMERS - CUSTOMER	285,488,986	SEC_CUST	-	247,087,363	-	-	247,087,363	-	2,197,459	-	-	2,197,459	
369	SERVICES	846,971,069	SERV	-	639,993,827	-	-	639,993,827	-	5,691,752	-	-	5,691,752	
370	METERS - DIST DIRECT	341,126,522	METERS	-	215,121,118	-	-	215,121,118	-	2,143,356	-	-	2,143,356	
371	INSTALLATIONS ON CUST PREMISES	15,029,035	AREALGT	-	-	-	-	-	-	-	-	-	-	
373	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615	STTRLGT	-	-	-	-	-	-	-	-	-	-	
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	621,595	STTRLGT	-	-	-	-	-	-	-	-	-	-	
	Sub-total	9,139,764,425		2,569,779,415	3,558,685,082	-	-	6,128,464,497	62,302,033	31,893,367	-	-	94,195,400	
General Plant														
389-399	GENERAL PLANT - DISTRIBUTION	1,061,552,192	LABOR	137,956,974	682,182,877	-	-	820,139,851	3,344,645	6,091,351	-	-	9,435,996	
	Sub-total	1,061,552,192		137,956,974	682,182,877	-	-	820,139,851	3,344,645	6,091,351	-	-	9,435,996	
TOTAL PLANT-IN-SERVICE														
		10,201,986,912		2,707,823,499	4,241,298,709	-	-	6,949,122,208	65,648,790	37,988,564	-	-	103,637,354	

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

Only Projected Future 1981 Fee		Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
RATE BASE														
Plant-in Service														
301-303	Intangible Plant													
	INTANGIBLE PLANT - DISTRIBUTION	670,295	LABOR	9,077	50,869	-	-	-	59,946	38,541	18,405	-	-	56,946
	Sub-total	670,295		9,077	50,869	-	-	-	59,946	38,541	18,405	-	-	56,946
	Distribution Plant													
360	LAND AND LAND RIGHTS	113,493,096	DPLT	3,325,131	5,741,395	-	-	-	9,066,526	14,118,353	2,900,056	-	-	17,018,409
361	STRUCTURES & IMPROVEMENTS	63,727,935	PRI_DEM	3,592,207	-	-	-	-	3,592,207	15,252,346	-	-	-	15,252,346
362	STATION EQUIPMENT	1,071,977,540	PRI_DEM	60,425,070	-	-	-	-	60,425,070	256,562,092	-	-	-	256,562,092
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	485,807,532	LABOR	6,578,774	36,867,894	-	-	-	43,446,668	27,933,175	13,339,623	-	-	41,272,798
364	POLES TOWERS & FIXTURES - PRI - DEMAND	537,975,079	PRI_DEM	30,324,499	-	-	-	-	30,324,499	128,756,440	-	-	-	128,756,440
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	840,388,740	PRI_CUST	-	82,397,701	-	-	-	82,397,701	-	22,266,888	-	-	22,266,888
364	POLES TOWERS & FIXTURES - SEC - DEMAND	100,896,363	SEC_DEM	6,661,236	-	-	-	-	6,661,236	28,283,306	-	-	-	28,283,306
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	402,471,412	SEC_CUST	-	39,493,647	-	-	-	39,493,647	-	10,672,635	-	-	10,672,635
365	OVERHEAD CONDUCTORS - PRI - DEMAND	764,864,095	PRI_DEM	43,113,745	-	-	-	-	43,113,745	183,058,996	-	-	-	183,058,996
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	628,932,106	PRI_CUST	-	61,664,986	-	-	-	61,664,986	-	16,664,146	-	-	16,664,146
365	OVERHEAD CONDUCTORS - SEC - DEMAND	436,593,319	SEC_DEM	28,824,144	-	-	-	-	28,824,144	122,386,003	-	-	-	122,386,003
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	116,846,029	SEC_CUST	-	11,465,848	-	-	-	11,465,848	-	3,098,494	-	-	3,098,494
366	UNDERGROUND CONDUIT - PRI - DEMAND	244,979,109	PRI_DEM	13,808,946	-	-	-	-	13,808,946	58,632,155	-	-	-	58,632,155
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	116,349,939	PRI_CUST	-	11,407,777	-	-	-	11,407,777	-	3,082,801	-	-	3,082,801
366	UNDERGROUND CONDUIT - SEC - DEMAND	11,950,350	SEC_DEM	788,969	-	-	-	-	788,969	3,349,927	-	-	-	3,349,927
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	4,614,402	SEC_CUST	-	452,801	-	-	-	452,801	-	122,364	-	-	122,364
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	644,919,075	PRI_DEM	36,352,702	-	-	-	-	36,352,702	154,351,916	-	-	-	154,351,916
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	306,296,709	PRI_CUST	-	30,031,512	-	-	-	30,031,512	-	8,115,619	-	-	8,115,619
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	31,459,861	SEC_DEM	2,076,998	-	-	-	-	2,076,998	8,818,840	-	-	-	8,818,840
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	12,147,632	SEC_CUST	-	1,192,021	-	-	-	1,192,021	-	322,128	-	-	322,128
368	LINE TRANSFORMERS - DEMAND	483,261,279	SEC_DEM	31,905,190	-	-	-	-	31,905,190	135,467,983	-	-	-	135,467,983
368	LINE TRANSFORMERS - CUSTOMER	285,488,986	SEC_CUST	-	28,014,415	-	-	-	28,014,415	-	7,570,525	-	-	7,570,525
369	SERVICES	846,971,069	SERV	-	114,558,037	-	-	-	114,558,037	-	85,579,599	-	-	85,579,599
370	METERS - DIST DIRECT	341,126,522	METERS	-	39,074,881	-	-	-	39,074,881	-	59,810,857	-	-	59,810,857
371	INSTALLATIONS ON CUST PREMISES	15,029,035	AREALGT	-	-	-	-	-	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615	STTRLGT	-	-	-	-	-	-	-	-	-	-	-
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	621,595	STTRLGT	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	9,139,764,425		267,777,612	462,362,914	-	-	-	730,140,527	1,136,971,533	233,545,735	-	-	1,370,517,268
	General Plant													
389-399	GENERAL PLANT - DISTRIBUTION	1,061,552,192	LABOR	14,375,471	80,561,109	-	-	-	94,936,580	61,037,594	29,148,799	-	-	90,186,393
	Sub-total	1,061,552,192		14,375,471	80,561,109	-	-	-	94,936,580	61,037,594	29,148,799	-	-	90,186,393
	TOTAL PLANT-IN-SERVICE	10,201,986,912		282,162,160	542,974,892	-	-	-	825,137,052	1,198,047,668	262,712,940	-	-	1,460,760,608

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No. Account Description

RATE BASE

Plant-in Service

301-303	Intangible Plant															
	INTANGIBLE PLANT - DISTRIBUTION	670,295	LABOR	266	541	-	-	807	383	9,384	-	-	9,766			
	Sub-total	670,295		266	541	-	-	807	383	9,384	-	-	9,766			
	Distribution Plant															
360	LAND AND LAND RIGHTS	113,493,096	DPLT	97,550	63,629	-	-	161,179	140,136	3,221,907	-	-	3,362,043			
361	STRUCTURES & IMPROVEMENTS	63,727,935	PRI_DEM	105,385	-	-	-	105,385	151,392	-	-	-	151,392			
362	STATION EQUIPMENT	1,071,977,540	PRI_DEM	1,772,704	-	-	-	1,772,704	2,546,580	-	-	-	2,546,580			
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	485,807,532	LABOR	193,003	391,853	-	-	584,856	277,259	6,800,937	-	-	7,078,196			
364	POLES TOWERS & FIXTURES - PRI - DEMAND	537,975,079	PRI_DEM	889,637	-	-	-	889,637	1,278,009	-	-	-	1,278,009			
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	840,388,740	PRI_CUST	-	825,612	-	-	825,612	-	995,687	-	-	995,687			
364	POLES TOWERS & FIXTURES - SEC - DEMAND	100,896,363	SEC_DEM	195,422	-	-	-	195,422	280,734	-	-	-	280,734			
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	402,471,412	SEC_CUST	-	395,720	-	-	395,720	-	477,238	-	-	477,238			
365	OVERHEAD CONDUCTORS - PRI - DEMAND	764,864,095	PRI_DEM	1,264,838	-	-	-	1,264,838	1,817,004	-	-	-	1,817,004			
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	628,932,106	PRI_CUST	-	617,874	-	-	617,874	-	745,155	-	-	745,155			
365	OVERHEAD CONDUCTORS - SEC - DEMAND	436,593,319	SEC_DEM	845,620	-	-	-	845,620	1,214,777	-	-	-	1,214,777			
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	116,846,029	SEC_CUST	-	114,886	-	-	114,886	-	138,552	-	-	138,552			
366	UNDERGROUND CONDUIT - PRI - DEMAND	244,979,109	PRI_DEM	405,116	-	-	-	405,116	581,970	-	-	-	581,970			
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	116,349,939	PRI_CUST	-	114,304	-	-	114,304	-	137,851	-	-	137,851			
366	UNDERGROUND CONDUIT - SEC - DEMAND	11,950,350	SEC_DEM	23,146	-	-	-	23,146	33,251	-	-	-	33,251			
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	4,614,402	SEC_CUST	-	4,537	-	-	4,537	-	5,472	-	-	5,472			
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	644,919,075	PRI_DEM	1,066,487	-	-	-	1,066,487	1,532,064	-	-	-	1,532,064			
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	306,296,709	PRI_CUST	-	300,911	-	-	300,911	-	362,898	-	-	362,898			
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	31,459,861	SEC_DEM	60,933	-	-	-	60,933	87,534	-	-	-	87,534			
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	12,147,632	SEC_CUST	-	11,944	-	-	11,944	-	14,404	-	-	14,404			
368	LINE TRANSFORMERS - DEMAND	483,261,279	SEC_DEM	936,010	-	-	-	936,010	1,344,626	-	-	-	1,344,626			
368	LINE TRANSFORMERS - CUSTOMER	285,488,986	SEC_CUST	-	280,700	-	-	280,700	-	338,524	-	-	338,524			
369	SERVICES	846,971,069	SERV	-	1,147,854	-	-	1,147,854	-	-	-	-	-			
370	METERS - DIST DIRECT	341,126,522	METERS	-	854,292	-	-	854,292	-	-	-	-	-			
371	INSTALLATIONS ON CUST PREMISES	15,029,035	AREALGT	-	-	-	-	-	-	15,029,035	-	-	15,029,035			
373	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615	STTRLGT	-	-	-	-	-	-	230,575,615	-	-	230,575,615			
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	621,595	STTRLGT	-	-	-	-	-	-	621,595	-	-	621,595			
	Sub-total	9,139,764,425		7,855,852	5,124,117	-	-	12,979,970	11,285,335	259,464,871	-	-	270,750,207			
	General Plant															
389-399	GENERAL PLANT - DISTRIBUTION	1,061,552,192	LABOR	421,736	856,249	-	-	1,277,985	605,846	14,860,927	-	-	15,466,773			
	Sub-total	1,061,552,192		421,736	856,249	-	-	1,277,985	605,846	14,860,927	-	-	15,466,773			
	TOTAL PLANT-IN-SERVICE	10,201,986,912		8,277,855	5,980,907	-	-	14,258,762	11,891,564	274,335,181	-	-	286,226,745			

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Accumulated Reserve for Depreciation													
Distribution Plant													
360	LAND AND LAND RIGHTS	41,596,195	PLT_360	11,695,383	16,196,015	-	-	27,891,398	283,544	145,151	-	-	428,695
361	STRUCTURES & IMPROVEMENTS - PRIMARY	21,397,940	PRI_DEM	11,575,107	-	-	-	11,575,107	280,628	-	-	-	280,628
362	STATION EQUIPMENT	234,310,665	PRI_DEM	126,749,167	-	-	-	126,749,167	3,072,922	-	-	-	3,072,922
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	136,518,580	LABOR	17,741,653	87,730,625	-	-	105,472,278	430,131	783,365	-	-	1,213,495
364	POLES TOWERS & FIXTURES - PRI - DEMAND	155,736,214	PRI_DEM	84,244,716	-	-	-	84,244,716	2,042,439	-	-	-	2,042,439
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	243,280,712	PRI_CUST	-	210,383,426	-	-	210,383,426	-	1,871,034	-	-	1,871,034
364	POLES TOWERS & FIXTURES - SEC - DEMAND	29,208,077	SEC_DEM	18,505,631	-	-	-	18,505,631	448,653	-	-	-	448,653
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	116,509,809	SEC_CUST	-	100,837,871	-	-	100,837,871	-	896,796	-	-	896,796
365	OVERHEAD CONDUCTORS - PRI - DEMAND	155,012,771	PRI_DEM	83,853,373	-	-	-	83,853,373	2,032,951	-	-	-	2,032,951
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	127,463,832	PRI_CUST	-	110,227,718	-	-	110,227,718	-	980,305	-	-	980,305
365	OVERHEAD CONDUCTORS - SEC - DEMAND	88,483,092	SEC_DEM	56,061,048	-	-	-	56,061,048	1,359,151	-	-	-	1,359,151
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	23,680,843	SEC_CUST	-	20,495,492	-	-	20,495,492	-	182,276	-	-	182,276
366	UNDERGROUND CONDUIT - PRI - DEMAND	59,787,185	PRI_DEM	32,341,575	-	-	-	32,341,575	784,093	-	-	-	784,093
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	28,395,219	PRI_CUST	-	24,555,516	-	-	24,555,516	-	218,383	-	-	218,383
366	UNDERGROUND CONDUIT - SEC - DEMAND	2,916,485	SEC_DEM	1,847,824	-	-	-	1,847,824	44,799	-	-	-	44,799
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	1,126,146	SEC_CUST	-	974,666	-	-	974,666	-	8,668	-	-	8,668
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	193,794,754	PRI_DEM	104,832,290	-	-	-	104,832,290	2,541,566	-	-	-	2,541,566
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	92,040,533	PRI_CUST	-	79,594,483	-	-	79,594,483	-	707,869	-	-	707,869
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	9,453,521	SEC_DEM	5,989,554	-	-	-	5,989,554	145,211	-	-	-	145,211
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	3,650,299	SEC_CUST	-	3,159,291	-	-	3,159,291	-	28,097	-	-	28,097
368	LINE TRANSFORMERS - DEMAND	166,055,435	SEC_DEM	105,209,272	-	-	-	105,209,272	2,550,706	-	-	-	2,550,706
368	LINE TRANSFORMERS - CUSTOMER	98,098,068	SEC_CUST	-	84,902,725	-	-	84,902,725	-	755,078	-	-	755,078
369	SERVICES	430,314,690	SERV	-	325,157,205	-	-	325,157,205	-	2,891,769	-	-	2,891,769
370	METERS - DIST DIRECT	197,489,696	METERS	-	124,540,900	-	-	124,540,900	-	1,240,861	-	-	1,240,861
371	INSTALLATIONS ON CUST PREMISES	8,531,974	AREALGT	-	-	-	-	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	STTRLGT	-	-	-	-	-	-	-	-	-	-
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	303,119	STTRLGT	-	-	-	-	-	-	-	-	-	-
	Sub-total	2,746,445,884		660,646,593	1,188,755,932	-	-	1,849,402,524	16,016,793	10,709,652	-	-	26,726,445
General Plant													
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	LABOR	66,230,843	327,504,622	-	-	393,735,464	1,605,708	2,924,356	-	-	4,530,064
	Sub-total	509,633,503		66,230,843	327,504,622	-	-	393,735,464	1,605,708	2,924,356	-	-	4,530,064
TOTAL DEPRECIATION ACCRUAL		3,256,079,387		726,877,435	1,516,260,553	-	-	2,243,137,989	17,622,502	13,634,008	-	-	31,256,509
NET PLANT		6,945,907,524		1,980,946,064	2,725,038,156	-	-	4,705,984,220	48,026,288	24,354,556	-	-	72,380,845

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Accumulated Reserve for Depreciation													
Distribution Plant													
360	LAND AND LAND RIGHTS	41,596,195	PLT_360	1,218,689	2,104,271	-	-	3,322,960	5,174,498	1,062,895	-	-	6,237,393
361	STRUCTURES & IMPROVEMENTS - PRIMARY	21,397,940	PRI_DEM	1,206,156	-	-	-	1,206,156	5,121,283	-	-	-	5,121,283
362	STATION EQUIPMENT	234,310,665	PRI_DEM	13,207,589	-	-	-	13,207,589	56,078,819	-	-	-	56,078,819
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	136,518,580	LABOR	1,848,726	10,360,384	-	-	12,209,110	7,849,605	3,748,617	-	-	11,598,222
364	POLES TOWERS & FIXTURES - PRI - DEMAND	155,736,214	PRI_DEM	8,778,516	-	-	-	8,778,516	37,273,177	-	-	-	37,273,177
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	243,280,712	PRI_CUST	-	23,852,975	-	-	23,852,975	-	6,445,951	-	-	6,445,951
364	POLES TOWERS & FIXTURES - SEC - DEMAND	29,208,077	SEC_DEM	1,928,334	-	-	-	1,928,334	8,187,619	-	-	-	8,187,619
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	116,509,809	SEC_CUST	-	11,432,855	-	-	11,432,855	-	3,089,578	-	-	3,089,578
365	OVERHEAD CONDUCTORS - PRI - DEMAND	155,012,771	PRI_DEM	8,737,737	-	-	-	8,737,737	37,100,032	-	-	-	37,100,032
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	127,463,832	PRI_CUST	-	12,497,462	-	-	12,497,462	-	3,377,274	-	-	3,377,274
365	OVERHEAD CONDUCTORS - SEC - DEMAND	88,483,092	SEC_DEM	5,841,705	-	-	-	5,841,705	24,803,614	-	-	-	24,803,614
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	23,680,843	SEC_CUST	-	2,323,750	-	-	2,323,750	-	627,963	-	-	627,963
366	UNDERGROUND CONDUIT - PRI - DEMAND	59,787,185	PRI_DEM	3,370,075	-	-	-	3,370,075	14,309,185	-	-	-	14,309,185
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	28,395,219	PRI_CUST	-	2,784,070	-	-	2,784,070	-	752,358	-	-	752,358
366	UNDERGROUND CONDUIT - SEC - DEMAND	2,916,485	SEC_DEM	192,548	-	-	-	192,548	817,550	-	-	-	817,550
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	1,126,146	SEC_CUST	-	110,506	-	-	110,506	-	29,863	-	-	29,863
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	193,794,754	PRI_DEM	10,923,794	-	-	-	10,923,794	46,381,930	-	-	-	46,381,930
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	92,040,533	PRI_CUST	-	9,024,310	-	-	9,024,310	-	2,438,700	-	-	2,438,700
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	9,453,521	SEC_DEM	624,127	-	-	-	624,127	2,650,015	-	-	-	2,650,015
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	3,650,299	SEC_CUST	-	358,196	-	-	358,196	-	96,798	-	-	96,798
368	LINE TRANSFORMERS - DEMAND	166,055,435	SEC_DEM	10,963,076	-	-	-	10,963,076	46,548,722	-	-	-	46,548,722
368	LINE TRANSFORMERS - CUSTOMER	98,098,068	SEC_CUST	-	9,626,151	-	-	9,626,151	-	2,601,340	-	-	2,601,340
369	SERVICES	430,314,690	SERV	-	58,202,704	-	-	58,202,704	-	43,479,831	-	-	43,479,831
370	METERS - DIST DIRECT	197,489,696	METERS	-	22,621,772	-	-	22,621,772	-	34,626,531	-	-	34,626,531
371	INSTALLATIONS ON CUST PREMISES	8,531,974	AREALGT	-	-	-	-	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	STTRLGT	-	-	-	-	-	-	-	-	-	-
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	303,119	STTRLGT	-	-	-	-	-	-	-	-	-	-
	Sub-total	2,746,445,884		68,841,071	165,299,404	-	-	234,140,475	292,296,049	102,377,698	-	-	394,673,747
General Plant													
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	LABOR	6,901,424	38,676,045	-	-	45,577,469	29,303,131	13,993,852	-	-	43,296,983
	Sub-total	509,633,503		6,901,424	38,676,045	-	-	45,577,469	29,303,131	13,993,852	-	-	43,296,983
TOTAL DEPRECIATION ACCRUAL		3,256,079,387		75,742,495	203,975,449	-	-	279,717,944	321,599,180	116,371,550	-	-	437,970,730
NET PLANT		6,945,907,524		206,419,665	338,999,443	-	-	545,419,109	876,448,488	146,341,390	-	-	1,022,789,878

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Accumulated Reserve for Depreciation															
Distribution Plant															
360	LAND AND LAND RIGHTS	41,596,195	PLT_360	2,299,442	86,590	-	-	2,386,032	-	38,426	-	-	-	-	38,426
361	STRUCTURES & IMPROVEMENTS - PRIMARY	21,397,940	PRI_DEM	3,128,548	-	-	-	3,128,548	-	-	-	-	-	-	-
362	STATION EQUIPMENT	234,310,665	PRI_DEM	34,258,068	-	-	-	34,258,068	-	-	-	-	-	-	-
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	136,518,580	LABOR	3,464,507	292,243	-	-	3,756,749	-	115,303	-	-	-	-	115,303
364	POLES TOWERS & FIXTURES - PRI - DEMAND	155,736,214	PRI_DEM	22,769,863	-	-	-	22,769,863	-	-	-	-	-	-	-
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	243,280,712	PRI_CUST	-	200,086	-	-	200,086	-	-	-	-	-	-	-
364	POLES TOWERS & FIXTURES - SEC - DEMAND	29,208,077	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	116,509,809	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS - PRI - DEMAND	155,012,771	PRI_DEM	22,664,090	-	-	-	22,664,090	-	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	127,463,832	PRI_CUST	-	104,832	-	-	104,832	-	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS - SEC - DEMAND	88,483,092	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	23,680,843	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
366	UNDERGROUND CONDUIT - PRI - DEMAND	59,787,185	PRI_DEM	8,741,358	-	-	-	8,741,358	-	-	-	-	-	-	-
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	28,395,219	PRI_CUST	-	23,354	-	-	23,354	-	-	-	-	-	-	-
366	UNDERGROUND CONDUIT - SEC - DEMAND	2,916,485	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	1,126,146	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	193,794,754	PRI_DEM	28,334,322	-	-	-	28,334,322	-	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	92,040,533	PRI_CUST	-	75,699	-	-	75,699	-	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	9,453,521	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	3,650,299	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
368	LINE TRANSFORMERS - DEMAND	166,055,435	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
368	LINE TRANSFORMERS - CUSTOMER	98,098,068	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
369	SERVICES	430,314,690	SERV	-	-	-	-	-	-	-	-	-	-	-	-
370	METERS - DIST DIRECT	197,489,696	METERS	-	9,375,197	-	-	9,375,197	-	4,589,856	-	-	-	-	4,589,856
371	INSTALLATIONS ON CUST PREMISES	8,531,974	AREALGT	-	-	-	-	-	-	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	303,119	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	2,746,445,884		125,660,199	10,158,001	-	-	135,818,200	-	4,743,585	-	-	-	-	4,743,585
General Plant															
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	LABOR	12,933,248	1,090,963	-	-	14,024,211	-	430,433	-	-	-	-	430,433
	Sub-total	509,633,503		12,933,248	1,090,963	-	-	14,024,211	-	430,433	-	-	-	-	430,433
	TOTAL DEPRECIATION ACCRUAL	3,256,079,387		138,593,446	11,248,964	-	-	149,842,411	-	5,174,018	-	-	-	-	5,174,018
	NET PLANT	6,945,907,524		393,610,275	10,051,079	-	-	403,661,354	-	4,166,399	-	-	-	-	4,166,399

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Accumulated Reserve for Depreciation													
Distribution Plant													
360	LAND AND LAND RIGHTS	41,596,195	PLT_360	35,753	23,320	-	-	59,073	51,361	1,180,857	-	-	1,232,218
361	STRUCTURES & IMPROVEMENTS - PRIMARY	21,397,940	PRI_DEM	35,385	-	-	-	35,385	50,833	-	-	-	50,833
362	STATION EQUIPMENT	234,310,665	PRI_DEM	387,474	-	-	-	387,474	556,626	-	-	-	556,626
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	136,518,580	LABOR	54,236	110,116	-	-	164,353	77,913	1,911,157	-	-	1,989,070
364	POLES TOWERS & FIXTURES - PRI - DEMAND	155,736,214	PRI_DEM	257,537	-	-	-	257,537	369,966	-	-	-	369,966
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	243,280,712	PRI_CUST	-	239,003	-	-	239,003	-	288,237	-	-	288,237
364	POLES TOWERS & FIXTURES - SEC - DEMAND	29,208,077	SEC_DEM	56,572	-	-	-	56,572	81,269	-	-	-	81,269
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	116,509,809	SEC_CUST	-	114,555	-	-	114,555	-	138,154	-	-	138,154
365	OVERHEAD CONDUCTORS - PRI - DEMAND	155,012,771	PRI_DEM	256,341	-	-	-	256,341	368,247	-	-	-	368,247
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	127,463,832	PRI_CUST	-	125,223	-	-	125,223	-	151,018	-	-	151,018
365	OVERHEAD CONDUCTORS - SEC - DEMAND	88,483,092	SEC_DEM	171,379	-	-	-	171,379	246,195	-	-	-	246,195
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	23,680,843	SEC_CUST	-	23,284	-	-	23,284	-	28,080	-	-	28,080
366	UNDERGROUND CONDUIT - PRI - DEMAND	59,787,185	PRI_DEM	98,869	-	-	-	98,869	142,030	-	-	-	142,030
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	28,395,219	PRI_CUST	-	27,896	-	-	27,896	-	33,642	-	-	33,642
366	UNDERGROUND CONDUIT - SEC - DEMAND	2,916,485	SEC_DEM	5,649	-	-	-	5,649	8,115	-	-	-	8,115
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	1,126,146	SEC_CUST	-	1,107	-	-	1,107	-	1,335	-	-	1,335
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	193,794,754	PRI_DEM	320,474	-	-	-	320,474	460,377	-	-	-	460,377
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	92,040,533	PRI_CUST	-	90,422	-	-	90,422	-	109,049	-	-	109,049
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	9,453,521	SEC_DEM	18,310	-	-	-	18,310	26,303	-	-	-	26,303
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	3,650,299	SEC_CUST	-	3,589	-	-	3,589	-	4,328	-	-	4,328
368	LINE TRANSFORMERS - DEMAND	166,055,435	SEC_DEM	321,626	-	-	-	321,626	462,033	-	-	-	462,033
368	LINE TRANSFORMERS - CUSTOMER	98,098,068	SEC_CUST	-	96,453	-	-	96,453	-	116,322	-	-	116,322
369	SERVICES	430,314,690	SERV	-	583,182	-	-	583,182	-	-	-	-	-
370	METERS - DIST DIRECT	197,489,696	METERS	-	494,579	-	-	494,579	-	-	-	-	-
371	INSTALLATIONS ON CUST PREMISES	8,531,974	AREALGT	-	-	-	-	-	-	8,531,974	-	-	8,531,974
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	STTRLGT	-	-	-	-	-	-	81,290,032	-	-	81,290,032
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	303,119	STTRLGT	-	-	-	-	-	-	303,119	-	-	303,119
	Sub-total	2,746,445,884		2,019,606	1,932,730	-	-	3,952,336	2,901,268	94,087,305	-	-	96,988,573
General Plant													
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	LABOR	202,469	411,071	-	-	613,540	290,857	7,134,483	-	-	7,425,340
	Sub-total	509,633,503		202,469	411,071	-	-	613,540	290,857	7,134,483	-	-	7,425,340
TOTAL DEPRECIATION ACCRUAL		3,256,079,387		2,222,075	2,343,800	-	-	4,565,875	3,192,124	101,221,788	-	-	104,413,912
NET PLANT		6,945,907,524		6,055,780	3,637,106	-	-	9,692,887	8,699,440	173,113,394	-	-	181,812,833

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Rate Base Adjustments													
Additions													
RB ADJ	PLANT HELD FOR FUTURE USE - DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-
RB ADJ	CASH WORKING CAPITAL - O&M	5,762,275	OMEXCLUNCO	995,847	3,294,452	-	-	4,290,299	24,143	29,671	-	-	53,815
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	19,449,818	TOTDPLT	5,468,603	7,573,037	-	-	13,041,640	132,581	67,870	-	-	200,452
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(15,007,233)	TOTDPLT	(4,219,505)	(5,843,260)	-	-	(10,062,764)	(102,298)	(52,368)	-	-	(154,666)
RB ADJ	MISCELLANEOUS PREPAYMENTS - DISTRIBUTION	6,257,237	TOTDPLT	1,759,314	2,436,336	-	-	4,195,650	42,653	21,835	-	-	64,488
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	TOTDPLT	20,284,778	28,090,791	-	-	48,375,569	491,787	251,753	-	-	743,540
	Sub-total	88,607,624		24,289,037	35,551,357	-	-	59,840,394	588,866	318,762	-	-	907,628
Deductions													
RB ADJ	CIAC - DISTRIBUTION	155,133,000	TOTDPLT	43,617,928	60,403,033	-	-	104,020,961	1,057,478	541,339	-	-	1,598,817
RB ADJ	CIAC - GENERAL	213,000	TOTDPLT	59,888	82,934	-	-	142,822	1,452	743	-	-	2,195
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	TOTDPLT	(218,961,815)	(303,222,969)	-	-	(522,184,784)	(5,308,536)	(2,717,521)	-	-	(8,026,057)
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	LABOR	(12,514,415)	(61,882,480)	-	-	(74,396,895)	(303,401)	(552,561)	-	-	(855,962)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	TOTDPLT	(140,663,341)	(194,793,581)	-	-	(335,456,923)	(3,410,259)	(1,745,764)	-	-	(5,156,022)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	LABOR	1,667,748	8,246,842	-	-	9,914,590	40,433	73,638	-	-	114,071
RB ADJ	CUSTOMER ADVANCES	-	ADVANCES	-	-	-	-	-	-	-	-	-	-
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	DEPOSIT	-	(1,979,388)	-	-	(1,979,388)	-	(12,432)	-	-	(12,432)
	Sub-total	(1,213,726,000)		(326,794,007)	(493,145,609)	-	-	(819,939,616)	(7,922,832)	(4,412,558)	-	-	(12,335,390)
TOTAL RATE BASE ADJ.													
		(1,125,118,376)		(302,504,969)	(457,594,252)	-	-	(760,099,222)	(7,333,966)	(4,093,796)	-	-	(11,427,762)
TOTAL RATE BASE													
		5,820,789,148		1,678,441,094	2,267,443,903	-	-	3,945,884,998	40,692,322	20,260,760	-	-	60,953,083

EXPENSES

O & M Expenses

Allocated Cost of Service Study		16	17	18	19	20	23	24	25	26	27	28	31
Detailed Cost Allocation Results		Small General Service - Sec. Voltage					Large General Service - Sec. Voltage						
Fully Projected Future Test Year		GS-1					GS-3						
No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Rate Base Adjustments													
Additions													
RB ADJ	PLANT HELD FOR FUTURE USE - DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-
RB ADJ	CASH WORKING CAPITAL - O&M	5,762,275	OMEXCLUNCO	103,770	410,172	-	-	513,942	440,602	164,291	-	-	604,893
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	19,449,818	TOTDPLT	569,842	983,928	-	-	1,553,771	2,419,525	496,996	-	-	2,916,521
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(15,007,233)	TOTDPLT	(439,683)	(759,187)	-	-	(1,198,870)	(1,866,875)	(383,475)	-	-	(2,250,350)
RB ADJ	MISCELLANEOUS PREPAYMENTS - DISTRIBUTION	6,257,237	TOTDPLT	183,325	316,541	-	-	499,867	778,390	159,889	-	-	938,279
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	TOTDPLT	2,113,726	3,649,702	-	-	5,763,428	8,974,784	1,843,514	-	-	10,818,297
	Sub-total	88,607,624		2,530,980	4,601,157	-	-	7,132,137	10,746,426	2,281,214	-	-	13,027,640
Deductions													
RB ADJ	CIAC - DISTRIBUTION	155,133,000	TOTDPLT	4,545,100	7,847,877	-	-	12,392,977	19,298,288	3,964,068	-	-	23,262,356
RB ADJ	CIAC - GENERAL	213,000	TOTDPLT	6,240	10,775	-	-	17,016	26,497	5,443	-	-	31,940
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	TOTDPLT	(22,816,383)	(39,396,309)	-	-	(62,212,692)	(96,877,323)	(19,899,606)	-	-	(116,776,929)
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	LABOR	(1,304,034)	(7,307,896)	-	-	(8,611,930)	(5,536,870)	(2,644,159)	-	-	(8,181,029)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	TOTDPLT	(14,657,481)	(25,308,597)	-	-	(39,966,079)	(62,234,997)	(12,783,713)	-	-	(75,018,711)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	LABOR	173,784	973,895	-	-	1,147,679	737,877	352,377	-	-	1,090,254
RB ADJ	CUSTOMER ADVANCES	-	ADVANCES	-	-	-	-	-	-	-	-	-	-
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	DEPOSIT	-	(1,532,390)	-	-	(1,532,390)	-	(2,858,783)	-	-	(2,858,783)
	Sub-total	(1,213,726,000)		(34,052,774)	(64,712,644)	-	-	(98,765,419)	(144,586,528)	(33,864,373)	-	-	(178,450,901)
TOTAL RATE BASE ADJ.		(1,125,118,376)		(31,521,794)	(60,111,487)	-	-	(91,633,282)	(133,840,102)	(31,583,159)	-	-	(165,423,261)
TOTAL RATE BASE		5,820,789,148		174,897,871	278,887,956	-	-	453,785,827	742,608,386	114,758,231	-	-	857,366,617

EXPENSES

O & M Expenses

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Rate Base Adjustments															
Additions															
RB ADJ	PLANT HELD FOR FUTURE USE - DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-	-	-
RB ADJ	CASH WORKING CAPITAL - O&M	5,762,275	OMEXCLUNCO	196,550	8,519	-	-	205,069	-	3,326	-	-	-	-	3,326
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	19,449,818	TOTDPLT	1,075,188	40,489	-	-	1,115,676	-	17,968	-	-	-	-	17,968
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(15,007,233)	TOTDPLT	(829,601)	(31,240)	-	-	(860,842)	-	(13,864)	-	-	-	-	(13,864)
RB ADJ	MISCELLANEOUS PREPAYMENTS - DISTRIBUTION	6,257,237	TOTDPLT	345,901	13,026	-	-	358,926	-	5,780	-	-	-	-	5,780
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	TOTDPLT	3,988,212	150,185	-	-	4,138,397	-	66,648	-	-	-	-	66,648
	Sub-total	88,607,624		4,776,249	180,977	-	-	4,957,227	-	79,858	-	-	-	-	79,858
Deductions															
RB ADJ	CIAC - DISTRIBUTION	155,133,000	TOTDPLT	8,575,768	322,939	-	-	8,898,707	-	143,311	-	-	-	-	143,311
RB ADJ	CIAC - GENERAL	213,000	TOTDPLT	11,775	443	-	-	12,218	-	197	-	-	-	-	197
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	TOTDPLT	(43,050,320)	(1,621,152)	-	-	(44,671,472)	-	(719,421)	-	-	-	-	(719,421)
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	LABOR	(2,443,756)	(206,139)	-	-	(2,649,895)	-	(81,331)	-	-	-	-	(81,331)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	TOTDPLT	(27,655,972)	(1,041,445)	-	-	(28,697,417)	-	(462,164)	-	-	-	-	(462,164)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	LABOR	325,670	27,471	-	-	353,141	-	10,839	-	-	-	-	10,839
RB ADJ	CUSTOMER ADVANCES	-	ADVANCES	-	-	-	-	-	-	-	-	-	-	-	-
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	DEPOSIT	-	(109,282)	-	-	(109,282)	-	-	-	-	-	-	-
	Sub-total	(1,213,726,000)		(64,236,836)	(2,627,165)	-	-	(66,864,000)	-	(1,108,569)	-	-	-	-	(1,108,569)
TOTAL RATE BASE ADJ.		(1,125,118,376)		(59,460,586)	(2,446,187)	-	-	(61,906,774)	-	(1,028,711)	-	-	-	-	(1,028,711)
TOTAL RATE BASE		5,820,789,148		334,149,689	7,604,892	-	-	341,754,581	-	3,137,688	-	-	-	-	3,137,688

EXPENSES

O & M Expenses

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Rate Base Adjustments													
Additions													
RB ADJ	PLANT HELD FOR FUTURE USE - DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-
RB ADJ	CASH WORKING CAPITAL - O&M	5,762,275	OMEXCLUNCO	3,044	4,302	-	-	7,347	4,373	79,211	-	-	83,585
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	19,449,818	TOTDPLT	16,718	10,904	-	-	27,622	24,016	552,153	-	-	576,168
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(15,007,233)	TOTDPLT	(12,899)	(8,414)	-	-	(21,313)	(18,530)	(426,034)	-	-	(444,564)
RB ADJ	MISCELLANEOUS PREPAYMENTS - DISTRIBUTION	6,257,237	TOTDPLT	5,378	3,508	-	-	8,886	7,726	177,634	-	-	185,360
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	TOTDPLT	62,011	40,448	-	-	102,459	89,082	2,048,109	-	-	2,137,190
	Sub-total	88,607,624		74,252	50,749	-	-	125,001	106,667	2,431,073	-	-	2,537,739
Deductions													
RB ADJ	CIAC - DISTRIBUTION	155,133,000	TOTDPLT	133,341	86,974	-	-	220,314	191,551	4,404,005	-	-	4,595,555
RB ADJ	CIAC - GENERAL	213,000	TOTDPLT	183	119	-	-	302	263	6,047	-	-	6,310
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	TOTDPLT	(669,369)	(436,608)	-	-	(1,105,977)	(961,584)	(22,108,084)	-	-	(23,069,667)
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	LABOR	(38,257)	(77,672)	-	-	(115,929)	(54,958)	(1,348,071)	-	-	(1,403,029)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	TOTDPLT	(430,010)	(280,481)	-	-	(710,491)	(617,731)	(14,202,462)	-	-	(14,820,194)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	LABOR	5,098	10,351	-	-	15,449	7,324	179,652	-	-	186,976
RB ADJ	CUSTOMER ADVANCES	-	ADVANCES	-	-	-	-	-	-	-	-	-	-
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	DEPOSIT	-	(14,516)	-	-	(14,516)	-	(47,209)	-	-	(47,209)
	Sub-total	(1,213,726,000)		(999,014)	(711,833)	-	-	(1,710,847)	(1,435,135)	(33,116,123)	-	-	(34,551,258)
TOTAL RATE BASE ADJ.													
		(1,125,118,376)		(924,762)	(661,084)	-	-	(1,585,846)	(1,328,468)	(30,685,050)	-	-	(32,013,518)
TOTAL RATE BASE													
		5,820,789,148		5,131,018	2,976,022	-	-	8,107,041	7,370,971	142,428,343	-	-	149,799,315

EXPENSES

O & M Expenses

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	10,367,332	DISTOPLBR	2,442,257	4,834,222	-	-	7,276,479	59,210	43,700	-	-	102,910
581	LOAD DISPATCHING	2,294,615	PLT_360_2	938,208	471,331	-	-	1,409,540	22,746	4,211	-	-	26,957
582	STATION EXPENSES	86,108	PLT_360_2	35,207	17,687	-	-	52,894	854	158	-	-	1,012
583	OVERHEAD LINES	29,067,041	PLT_364_5	7,934,003	13,055,745	-	-	20,989,748	192,353	116,111	-	-	308,463
584	UNDERGROUND LINES	6,594,454	PLT_366_7	2,444,677	1,825,509	-	-	4,270,186	59,269	16,235	-	-	75,504
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	2,391,010	METERS	-	1,507,818	-	-	1,507,818	-	15,023	-	-	15,023
587	CUSTOMER INSTALLATION EXPENSE	3,025,958	PLT_369	-	2,286,494	-	-	2,286,494	-	20,335	-	-	20,335
588	MISC. DISTRIBUTION EXPENSE	18,180,878	DPLT	5,111,822	7,078,959	-	-	12,190,781	123,932	63,442	-	-	187,374
589	RENTS	7,534,350	DPLT	2,118,393	2,933,596	-	-	5,051,990	51,359	26,291	-	-	77,650
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000	LABOR	176,613	873,331	-	-	1,049,944	4,282	7,798	-	-	12,080
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(474,619)	LABOR	(61,680)	(305,003)	-	-	(366,683)	(1,495)	(2,723)	-	-	(4,219)
PROFORMA	RATE CASE EXPENSES	733,000	TOTPLT	194,554	304,732	-	-	499,286	4,717	2,729	-	-	7,446
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000	DEPOSIT	-	90,604	-	-	90,604	-	569	-	-	569
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000	TOTPLT	106,168	166,293	-	-	272,462	2,574	1,489	-	-	4,063
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE RATES	-	TOTPLT	-	-	-	-	-	-	-	-	-	-
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000	TOTPLT	1,003,027	1,571,054	-	-	2,574,080	24,317	14,072	-	-	38,389
PROFORMA	IJA-RELATED INCREMENTAL EXPENDITURES	211,000	TOTPLT	56,004	87,720	-	-	143,723	1,358	786	-	-	2,143
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)	TOTPLT	(371,590)	(582,026)	-	-	(953,615)	(9,009)	(5,213)	-	-	(14,222)
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)	LABOR	(237,303)	(1,173,438)	-	-	(1,410,741)	(5,753)	(10,478)	-	-	(16,231)
	Sub-total	82,623,129		21,890,360	35,044,629	-	-	56,934,989	530,712	314,535	-	-	845,247
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	137,306	PLT_360_2	56,141	28,204	-	-	84,344	1,361	252	-	-	1,613
592	STATION EQUIPMENT	12,304,925	PLT_360_2	5,031,163	2,527,525	-	-	7,558,688	121,976	22,579	-	-	144,555
593	OVERHEAD LINES	85,378,325	PLT_364_5	23,304,466	38,348,508	-	-	61,652,975	564,996	341,050	-	-	906,047
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	25,336,746	SERV	-	19,145,118	-	-	19,145,118	-	170,266	-	-	170,266
594	UNDERGROUND LINES	340,244	PLT_366_7	126,134	94,188	-	-	220,322	3,058	838	-	-	3,896
595	LINE TRANSFORMERS - DEMAND	114,589	SEC_DEM	72,601	-	-	-	72,601	1,760	-	-	-	1,760
595	LINE TRANSFORMERS - CUSTOMER	67,694	SEC_CUST	-	58,589	-	-	58,589	-	521	-	-	521
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105	STTRLGT	-	-	-	-	-	-	-	-	-	-
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606	DPLT	581,057	804,660	-	-	1,385,717	14,087	7,211	-	-	21,299
	Sub-total	128,170,541		29,171,563	61,006,791	-	-	90,178,354	707,239	542,718	-	-	1,249,957
	Total Distribution	210,793,669		51,061,923	96,051,421	-	-	147,113,343	1,237,951	857,252	-	-	2,095,204
Customer Account													
901	SUPERVISION	4,016,323	CUSTACCTLBR	-	3,473,138	-	-	3,473,138	-	30,888	-	-	30,888
902	METER READING	1,205,576	MTREAD	-	1,043,675	-	-	1,043,675	-	9,282	-	-	9,282
903CR	CUSTOMER RECORDS	25,189,595	CUST	-	21,780,962	-	-	21,780,962	-	193,708	-	-	193,708
903CE	COLLECTION EXPENSES	14,177,408	GRSWRTOFF	-	12,906,629	-	-	12,906,629	-	43,785	-	-	43,785
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000	TOTDPLT	1,186,515	1,643,111	-	-	2,829,627	28,766	14,726	-	-	43,492
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983	GRSWRTOFF	-	29,901,864	-	-	29,901,864	-	101,440	-	-	101,440
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596	CUST	-	3,102,990	-	-	3,102,990	-	27,596	-	-	27,596
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504	GRSWRTOFF	-	5,845,919	-	-	5,845,919	-	19,832	-	-	19,832
904-MFC	MFC ADJUSTMENT (@ Present Rates)	(18,111,000)	GRSWRTOFF	-	(16,487,638)	-	-	(16,487,638)	-	(55,933)	-	-	(55,933)
	Sub-total	73,553,985		1,186,515	63,210,651	-	-	64,397,166	28,766	385,323	-	-	414,089

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	Small General Service - Sec. Voltage					Large General Service - Sec. Voltage				
				DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	10,367,332	DISTOPLBR	254,489	641,014	-	-	895,503	1,080,550	386,662	-	-	1,467,213
581	LOAD DISPATCHING	2,294,615	PLT_360_2	97,764	56,352	-	-	154,116	415,100	21,478	-	-	436,578
582	STATION EXPENSES	86,108	PLT_360_2	3,669	2,115	-	-	5,783	15,577	806	-	-	16,383
583	OVERHEAD LINES	29,067,041	PLT_364_5	826,743	1,480,242	-	-	2,306,985	3,510,315	400,016	-	-	3,910,331
584	UNDERGROUND LINES	6,594,454	PLT_366_7	254,742	206,974	-	-	461,715	1,081,621	55,932	-	-	1,137,553
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	2,391,010	METERS	-	273,882	-	-	273,882	-	419,224	-	-	419,224
587	CUSTOMER INSTALLATION EXPENSE	3,025,958	PLT_369	-	409,279	-	-	409,279	-	305,749	-	-	305,749
588	MISC. DISTRIBUTION EXPENSE	18,180,878	DPLT	532,665	919,735	-	-	1,452,400	2,261,671	464,571	-	-	2,726,242
589	RENTS	7,534,350	DPLT	220,742	381,148	-	-	601,890	937,261	192,523	-	-	1,129,784
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000	LABOR	18,403	103,134	-	-	121,538	78,140	37,316	-	-	115,457
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(474,619)	LABOR	(6,427)	(36,019)	-	-	(42,446)	(27,290)	(13,032)	-	-	(40,322)
PROFORMA	RATE CASE EXPENSES	733,000	TOTPLT	20,273	39,012	-	-	59,285	86,078	18,876	-	-	104,954
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000	DEPOSIT	-	70,143	-	-	70,143	-	130,857	-	-	130,857
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000	TOTPLT	11,063	21,289	-	-	32,352	46,973	10,300	-	-	57,274
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE RATES	-	TOTPLT	-	-	-	-	-	-	-	-	-	-
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000	TOTPLT	104,518	201,128	-	-	305,646	443,778	97,314	-	-	541,092
PROFORMA	IJA-RELATED INCREMENTAL EXPENDITURES	211,000	TOTPLT	5,836	11,230	-	-	17,066	24,778	5,433	-	-	30,212
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)	TOTPLT	(38,721)	(74,511)	-	-	(113,232)	(164,406)	(36,052)	-	-	(200,458)
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)	LABOR	(24,728)	(138,575)	-	-	(163,303)	(104,992)	(50,140)	-	-	(155,132)
	Sub-total	82,623,129		2,281,032	4,567,572	-	-	6,848,604	9,685,157	2,447,833	-	-	12,132,989
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	137,306	PLT_360_2	5,850	3,372	-	-	9,222	24,839	1,285	-	-	26,124
592	STATION EQUIPMENT	12,304,925	PLT_360_2	524,260	302,191	-	-	826,452	2,225,985	115,174	-	-	2,341,159
593	OVERHEAD LINES	85,378,325	PLT_364_5	2,428,385	4,347,900	-	-	6,776,285	10,310,813	1,174,962	-	-	11,485,775
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	25,336,746	SERV	-	3,426,950	-	-	3,426,950	-	2,560,074	-	-	2,560,074
594	UNDERGROUND LINES	340,244	PLT_366_7	13,144	10,679	-	-	23,822	55,807	2,886	-	-	58,693
595	LINE TRANSFORMERS - DEMAND	114,589	SEC_DEM	7,565	-	-	-	7,565	32,122	-	-	-	32,122
595	LINE TRANSFORMERS - CUSTOMER	67,694	SEC_CUST	-	6,643	-	-	6,643	-	1,795	-	-	1,795
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105	STTRLGT	-	-	-	-	-	-	-	-	-	-
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606	DPLT	60,548	104,546	-	-	165,093	257,082	52,807	-	-	309,890
	Sub-total	128,170,541		3,039,752	8,202,281	-	-	11,242,032	12,906,647	3,908,984	-	-	16,815,631
	Total Distribution	210,793,669		5,320,783	12,769,853	-	-	18,090,637	22,591,804	6,356,817	-	-	28,948,621
Customer Account													
901	SUPERVISION	4,016,323	CUSTACCTLBR	-	393,779	-	-	393,779	-	106,414	-	-	106,414
902	METER READING	1,205,576	MTREAD	-	118,330	-	-	118,330	-	31,977	-	-	31,977
903CR	CUSTOMER RECORDS	25,189,595	CUST	-	2,469,495	-	-	2,469,495	-	667,348	-	-	667,348
903CE	COLLECTION EXPENSES	14,177,408	GRSWRTOFF	-	531,541	-	-	531,541	-	596,218	-	-	596,218
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000	TOTDPLT	123,638	213,482	-	-	337,120	524,961	107,832	-	-	632,793
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983	GRSWRTOFF	-	1,231,465	-	-	1,231,465	-	1,381,308	-	-	1,381,308
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596	CUST	-	351,813	-	-	351,813	-	95,073	-	-	95,073
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504	GRSWRTOFF	-	240,756	-	-	240,756	-	270,051	-	-	270,051
904-MFC	MFC ADJUSTMENT (@ Present Rates)	(18,111,000)	GRSWRTOFF	-	(679,019)	-	-	(679,019)	-	(761,642)	-	-	(761,642)
	Sub-total	73,553,985		123,638	4,871,640	-	-	4,995,278	524,961	2,494,579	-	-	3,019,540

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Distribution Operation Expenses															
580	SUPERVISION AND ENGINEERING	10,367,332	DISTOPLBR	476,953	52,190	-	-	529,143	-	24,351	-	-	-	-	24,351
581	LOAD DISPATCHING	2,294,615	PLT_360_2	244,209	1,688	-	-	245,897	-	681	-	-	-	-	681
582	STATION EXPENSES	86,108	PLT_360_2	9,164	63	-	-	9,228	-	26	-	-	-	-	26
583	OVERHEAD LINES	29,067,041	PLT_364_5	1,445,807	9,172	-	-	1,454,979	-	-	-	-	-	-	-
584	UNDERGROUND LINES	6,594,454	PLT_366_7	625,042	1,670	-	-	626,712	-	-	-	-	-	-	-
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	2,391,010	METERS	-	113,506	-	-	113,506	-	55,569	-	-	-	-	55,569
587	CUSTOMER INSTALLATION EXPENSE	3,025,958	PLT_369	-	-	-	-	-	-	-	-	-	-	-	-
588	MISC. DISTRIBUTION EXPENSE	18,180,878	DPLT	1,005,041	37,847	-	-	1,042,888	-	16,795	-	-	-	-	16,795
589	RENTS	7,534,350	DPLT	416,500	15,684	-	-	432,184	-	6,960	-	-	-	-	6,960
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-	-	-
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000	LABOR	34,488	2,909	-	-	37,397	-	1,148	-	-	-	-	1,148
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(474,619)	LABOR	(12,045)	(1,016)	-	-	(13,061)	-	(401)	-	-	-	-	(401)
PROFORMA	RATE CASE EXPENSES	733,000	TOTPLT	38,238	1,530	-	-	39,769	-	671	-	-	-	-	671
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000	DEPOSIT	-	5,002	-	-	5,002	-	-	-	-	-	-	-
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000	TOTPLT	20,867	835	-	-	21,702	-	366	-	-	-	-	366
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE RATES	-	TOTPLT	-	-	-	-	-	-	-	-	-	-	-	-
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000	TOTPLT	197,138	7,890	-	-	205,028	-	3,460	-	-	-	-	3,460
PROFORMA	I/JA-RELATED INCREMENTAL EXPENDITURES	211,000	TOTPLT	11,007	441	-	-	11,448	-	193	-	-	-	-	193
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)	TOTPLT	(73,033)	(2,923)	-	-	(75,956)	-	(1,282)	-	-	-	-	(1,282)
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)	LABOR	(46,339)	(3,909)	-	-	(50,248)	-	(1,542)	-	-	-	-	(1,542)
	Sub-total	82,623,129		4,393,036	242,580	-	-	4,635,616	-	106,996	-	-	-	-	106,996
Distribution Maintenance Expenses															
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	137,306	PLT_360_2	14,613	101	-	-	14,714	-	41	-	-	-	-	41
592	STATION EQUIPMENT	12,304,925	PLT_360_2	1,309,577	9,051	-	-	1,318,628	-	3,654	-	-	-	-	3,654
593	OVERHEAD LINES	85,378,325	PLT_364_5	4,246,754	26,941	-	-	4,273,696	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	25,336,746	SERV	-	-	-	-	-	-	-	-	-	-	-	-
594	UNDERGROUND LINES	340,244	PLT_366_7	32,249	86	-	-	32,335	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - DEMAND	114,589	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - CUSTOMER	67,694	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606	DPLT	114,242	4,302	-	-	118,544	-	1,909	-	-	-	-	1,909
	Sub-total	128,170,541		5,717,436	40,482	-	-	5,757,918	-	5,603	-	-	-	-	5,603
	Total Distribution	210,793,669		10,110,472	283,062	-	-	10,393,533	-	112,600	-	-	-	-	112,600
Customer Account															
901	SUPERVISION	4,016,323	CUSTACCTLBR	-	3,303	-	-	3,303	-	444	-	-	-	-	444
902	METER READING	1,205,576	MTREAD	-	993	-	-	993	-	133	-	-	-	-	133
903CR	CUSTOMER RECORDS	25,189,595	CUST	-	20,715	-	-	20,715	-	2,782	-	-	-	-	2,782
903CE	COLLECTION EXPENSES	14,177,408	GRSWRTOFF	-	92,533	-	-	92,533	-	3,781	-	-	-	-	3,781
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000	TOTDPLT	233,282	8,785	-	-	242,067	-	3,898	-	-	-	-	3,898
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983	GRSWRTOFF	-	214,378	-	-	214,378	-	8,759	-	-	-	-	8,759
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596	CUST	-	2,951	-	-	2,951	-	396	-	-	-	-	396
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504	GRSWRTOFF	-	41,912	-	-	41,912	-	1,712	-	-	-	-	1,712
904-MFC	MFC ADJUSTMENT (@ Present Rates)	(18,111,000)	GRSWRTOFF	-	(118,206)	-	-	(118,206)	-	(4,830)	-	-	-	-	(4,830)
	Sub-total	73,553,985		233,282	267,363	-	-	500,645	-	17,077	-	-	-	-	17,077

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	10,367,332	DISTOPLBR	7,466	7,844	-	-	15,310	10,725	45,698	-	-	56,423
581	LOAD DISPATCHING	2,294,615	PLT_360_2	2,868	602	-	-	3,471	4,120	13,256	-	-	17,376
582	STATION EXPENSES	86,108	PLT_360_2	108	23	-	-	130	155	497	-	-	652
583	OVERHEAD LINES	29,067,041	PLT_364_5	24,254	14,832	-	-	39,086	34,843	22,605	-	-	57,448
584	UNDERGROUND LINES	6,594,454	PLT_366_7	7,473	2,074	-	-	9,547	10,736	2,501	-	-	13,237
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	2,391,010	METERS	-	5,988	-	-	5,988	-	-	-	-	-
587	CUSTOMER INSTALLATION EXPENSE	3,025,958	PLT_369	-	4,101	-	-	4,101	-	-	-	-	-
588	MISC. DISTRIBUTION EXPENSE	18,180,878	DPLT	15,627	10,193	-	-	25,820	22,449	516,129	-	-	538,578
589	RENTS	7,534,350	DPLT	6,476	4,224	-	-	10,700	9,303	213,889	-	-	223,192
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000	LABOR	540	1,096	-	-	1,636	776	19,025	-	-	19,801
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(474,619)	LABOR	(189)	(383)	-	-	(571)	(271)	(6,644)	-	-	(6,915)
PROFORMA	RATE CASE EXPENSES	733,000	TOTPLT	595	430	-	-	1,024	854	19,711	-	-	20,565
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000	DEPOSIT	-	664	-	-	664	-	2,161	-	-	2,161
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000	TOTPLT	325	234	-	-	559	466	10,756	-	-	11,222
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE RATES	-	TOTPLT	-	-	-	-	-	-	-	-	-	-
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000	TOTPLT	3,066	2,215	-	-	5,282	4,405	101,619	-	-	106,024
PROFORMA	I/JA-RELATED INCREMENTAL EXPENDITURES	211,000	TOTPLT	171	124	-	-	295	246	5,674	-	-	5,920
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)	TOTPLT	(1,136)	(821)	-	-	(1,957)	(1,632)	(37,647)	-	-	(39,278)
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)	LABOR	(725)	(1,473)	-	-	(2,198)	(1,042)	(25,563)	-	-	(26,605)
	Sub-total	82,623,129		66,919	51,968	-	-	118,887	96,133	903,667	-	-	999,800
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	137,306	PLT_360_2	172	36	-	-	208	247	793	-	-	1,040
592	STATION EQUIPMENT	12,304,925	PLT_360_2	15,380	3,230	-	-	18,611	22,095	71,084	-	-	93,178
593	OVERHEAD LINES	85,378,325	PLT_364_5	71,242	43,565	-	-	114,807	102,343	66,398	-	-	168,741
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	25,336,746	SERV	-	34,338	-	-	34,338	-	-	-	-	-
594	UNDERGROUND LINES	340,244	PLT_366_7	386	107	-	-	493	554	129	-	-	683
595	LINE TRANSFORMERS - DEMAND	114,589	SEC_DEM	222	-	-	-	222	319	-	-	-	319
595	LINE TRANSFORMERS - CUSTOMER	67,694	SEC_CUST	-	67	-	-	67	-	80	-	-	80
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105	STTRLGT	-	-	-	-	-	-	2,424,105	-	-	2,424,105
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606	DPLT	1,776	1,159	-	-	2,935	2,552	58,668	-	-	61,220
	Sub-total	128,170,541		89,178	82,501	-	-	171,679	128,109	2,621,257	-	-	2,749,366
	Total Distribution	210,793,669		156,097	134,469	-	-	290,566	224,241	3,524,925	-	-	3,749,166
Customer Account													
901	SUPERVISION	4,016,323	CUSTACCTLBR	-	3,946	-	-	3,946	-	4,411	-	-	4,411
902	METER READING	1,205,576	MTREAD	-	1,186	-	-	1,186	-	-	-	-	-
903CR	CUSTOMER RECORDS	25,189,595	CUST	-	24,744	-	-	24,744	-	29,841	-	-	29,841
903CE	COLLECTION EXPENSES	14,177,408	GRSWRTOFF	-	2,922	-	-	2,922	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000	TOTDPLT	3,627	2,366	-	-	5,993	5,211	119,800	-	-	125,010
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983	GRSWRTOFF	-	6,769	-	-	6,769	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596	CUST	-	3,525	-	-	3,525	-	4,251	-	-	4,251
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504	GRSWRTOFF	-	1,323	-	-	1,323	-	-	-	-	-
904-MFC	MFC ADJUSTMENT (@ Present Rates)	(18,111,000)	GRSWRTOFF	-	(3,732)	-	-	(3,732)	-	-	-	-	-
	Sub-total	73,553,985		3,627	43,048	-	-	46,675	5,211	158,304	-	-	163,514

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Customer Service & Information Expenses													
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873	CUST	-	19,046,216	-	-	19,046,216	-	169,387	-	-	169,387
	Sub-total	22,026,873		-	19,046,216	-	-	19,046,216	-	169,387	-	-	169,387
Sales Expenses													
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-
Administrative and General Expenses													
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572	LABOR	11,216,081	55,462,354	-	-	66,678,435	271,924	495,235	-	-	767,159
924	PROPERTY INSURANCE - DIST	2,058,405	TOTDPLT	578,751	801,466	-	-	1,380,217	14,031	7,183	-	-	21,214
925	INJURIES & DAMAGES - DIST	6,965,752	LABOR	905,254	4,476,385	-	-	5,381,639	21,947	39,971	-	-	61,918
926	EMPLOYEE BENEFITS - DIST	2,395,082	LABOR	311,260	1,539,146	-	-	1,850,406	7,546	13,743	-	-	21,290
927	FRANCHISE REQUIREMENTS - DIST	-	NETTOTPLT	-	-	-	-	-	-	-	-	-	-
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737	NETTOTPLT	1,900,472	2,614,336	-	-	4,514,808	46,075	23,365	-	-	69,440
928F	REGULATORY COMMISSION EXPENSE - FERC - DIST	-	NETTOTPLT	-	-	-	-	-	-	-	-	-	-
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)	TOTDPLT	(3,623,049)	(5,017,275)	-	-	(8,640,325)	(87,838)	(44,965)	-	-	(132,803)
933	TRANSPORTATION EXPENSES - DIST	916,027	LABOR	119,045	588,664	-	-	707,709	2,886	5,256	-	-	8,142
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748	LABOR	4,993,985	24,694,736	-	-	29,688,721	121,075	220,504	-	-	341,579
928	PUC FEE INCREASE	1,110,654	NETTOTPLT	316,754	435,735	-	-	752,489	7,679	3,894	-	-	11,574
	Sub-total	131,957,117		16,718,552	85,595,548	-	-	102,314,101	405,327	764,186	-	-	1,169,513
	TOTAL O & M EXPENSES	438,331,644		68,966,990	263,903,836	-	-	332,870,826	1,672,044	2,176,148	-	-	3,848,192

Labor Expense

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	16	17	18	19	20	23	24	25	26	27	28	31
				Small General Service - Sec. Voltage					Large General Service - Sec. Voltage						
				GS-1					GS-3						
				DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL		
Customer Service & Information Expenses															
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873	CUST	-	2,159,433	-	-	2,159,433	-	583,558	-	-	-	583,558	-
	Sub-total	22,026,873		-	2,159,433	-	-	2,159,433	-	583,558	-	-	-	583,558	
Sales Expenses															
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-	-	-
Administrative and General Expenses															
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572	LABOR	1,168,744	6,549,723	-	-	7,718,467	4,962,436	2,369,835	-	-	-	7,332,271	
924	PROPERTY INSURANCE - DIST	2,058,405	TOTDPLT	60,307	104,131	-	-	164,438	256,062	52,598	-	-	-	308,660	
925	INJURIES & DAMAGES - DIST	6,965,752	LABOR	94,330	528,630	-	-	622,960	400,520	191,270	-	-	-	591,790	
926	EMPLOYEE BENEFITS - DIST	2,395,082	LABOR	32,434	181,763	-	-	214,197	137,713	65,766	-	-	-	203,479	
927	FRANCHISE REQUIREMENTS - DIST	-	NETTOTPLT	-	-	-	-	-	-	-	-	-	-	-	-
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737	NETTOTPLT	198,034	325,228	-	-	523,262	840,844	140,396	-	-	-	981,240	
928F	REGULATORY COMMISSION EXPENSE - FERC - DIST	-	NETTOTPLT	-	-	-	-	-	-	-	-	-	-	-	-
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)	TOTDPLT	(377,531)	(651,871)	-	-	(1,029,402)	(1,602,980)	(329,269)	-	-	-	(1,932,248)	
933	TRANSPORTATION EXPENSES - DIST	916,027	LABOR	12,405	69,517	-	-	81,922	52,670	25,153	-	-	-	77,823	
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748	LABOR	520,386	2,916,279	-	-	3,436,665	2,209,536	1,055,174	-	-	-	3,264,710	
928	PUC FEE INCREASE	1,110,654	NETTOTPLT	33,007	54,206	-	-	87,213	140,144	23,400	-	-	-	163,545	
	Sub-total	131,957,117		1,742,116	10,077,606	-	-	11,819,722	7,396,945	3,594,324	-	-	-	10,991,270	
	TOTAL O & M EXPENSES	438,331,644		7,186,537	29,878,532	-	-	37,065,070	30,513,710	13,029,278	-	-	-	43,542,989	

Labor Expense

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Customer Service & Information Expenses															
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873	CUST	-	18,114	-	-	18,114	-	2,433	-	-	-	-	2,433
	Sub-total	22,026,873		-	18,114	-	-	18,114	-	2,433	-	-	-	-	2,433
Sales Expenses															
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-	-	-
Administrative and General Expenses															
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572	LABOR	2,190,224	184,753	-	-	2,374,976	-	72,893	-	-	-	-	72,893
924	PROPERTY INSURANCE - DIST	2,058,405	TOTDPLT	113,789	4,285	-	-	118,074	-	1,902	-	-	-	-	1,902
925	INJURIES & DAMAGES - DIST	6,965,752	LABOR	176,774	14,911	-	-	191,685	-	5,883	-	-	-	-	5,883
926	EMPLOYEE BENEFITS - DIST	2,395,082	LABOR	60,781	5,127	-	-	65,908	-	2,023	-	-	-	-	2,023
927	FRANCHISE REQUIREMENTS - DIST	-	NETTOTPLT	-	-	-	-	-	-	-	-	-	-	-	-
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737	NETTOTPLT	377,620	9,643	-	-	387,263	-	3,997	-	-	-	-	3,997
928F	REGULATORY COMMISSION EXPENSE - FERC - DIST	-	NETTOTPLT	-	-	-	-	-	-	-	-	-	-	-	-
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)	TOTDPLT	(712,332)	(26,824)	-	-	(739,156)	-	(11,904)	-	-	-	-	(11,904)
933	TRANSPORTATION EXPENSES - DIST	916,027	LABOR	23,247	1,961	-	-	25,207	-	774	-	-	-	-	774
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748	LABOR	975,202	82,262	-	-	1,057,464	-	32,456	-	-	-	-	32,456
928	PUC FEE INCREASE	1,110,654	NETTOTPLT	62,938	1,607	-	-	64,546	-	666	-	-	-	-	666
	Sub-total	131,957,117		3,268,243	277,724	-	-	3,545,967	-	108,690	-	-	-	-	108,690
	TOTAL O & M EXPENSES	438,331,644		13,611,997	846,263	-	-	14,458,259	-	240,799	-	-	-	-	240,799

Labor Expense

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	48	49	50	51	52	55	56	57	58	59	60	63	64
				Separate Meter General Space Heating Service					Street Lighting/Area Lighting							
				GH-2					SL/AL							
				DEM	CUS	FUL	REV	TOTAL		DEM	CUS	FUL	REV	TOTAL		
Customer Service & Information Expenses																
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873	CUST	-	21,637	-	-	21,637	-	-	26,094	-	-	-	26,094	-
	Sub-total	22,026,873		-	21,637	-	-	21,637	-	-	26,094	-	-	-	26,094	-
Sales Expenses																
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Administrative and General Expenses																
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572	LABOR	34,288	69,614	-	-	103,902		49,256	1,208,213	-	-	-	1,257,469	
924	PROPERTY INSURANCE - DIST	2,058,405	TOTDPLT	1,769	1,154	-	-	2,923		2,542	58,435	-	-	-	60,977	
925	INJURIES & DAMAGES - DIST	6,965,752	LABOR	2,767	5,619	-	-	8,386		3,975	97,515	-	-	-	101,491	
926	EMPLOYEE BENEFITS - DIST	2,395,082	LABOR	952	1,932	-	-	2,883		1,367	33,529	-	-	-	34,896	
927	FRANCHISE REQUIREMENTS - DIST	-	NETTOTPLT	-	-	-	-	-		-	-	-	-	-	-	
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737	NETTOTPLT	5,810	3,489	-	-	9,299		8,346	166,081	-	-	-	174,427	
928F	REGULATORY COMMISSION EXPENSE - FERC - DIST	-	NETTOTPLT	-	-	-	-	-		-	-	-	-	-	-	
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)	TOTDPLT	(11,076)	(7,224)	-	-	(18,300)		(15,911)	(365,811)	-	-	-	(381,722)	
933	TRANSPORTATION EXPENSES - DIST	916,027	LABOR	364	739	-	-	1,103		523	12,824	-	-	-	13,346	
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748	LABOR	15,267	30,996	-	-	46,263		21,931	537,959	-	-	-	559,891	
928	PUC FEE INCREASE	1,110,654	NETTOTPLT	968	582	-	-	1,550		1,391	27,681	-	-	-	29,072	
	Sub-total	131,957,117		51,109	106,900	-	-	158,009		73,420	1,776,426	-	-	-	1,849,847	
	TOTAL O & M EXPENSES	438,331,644		210,833	306,055	-	-	516,888		302,873	5,485,749	-	-	-	5,788,621	

Labor Expense

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	2,531,568	DISTOPLBR	596,367	1,180,455	-	-	1,776,822	14,458	10,671	-	-	25,129
581	LOAD DISPATCHING	205,354	PLT_360_2	83,964	42,181	-	-	126,145	2,036	377	-	-	2,412
582	STATION EXPENSES	63,106	PLT_360_2	25,802	12,962	-	-	38,765	626	116	-	-	741
583	OVERHEAD LINES	11,129,059	PLT_364_5	3,037,736	4,998,725	-	-	8,036,461	73,647	44,456	-	-	118,103
584	UNDERGROUND LINES	1,412,410	PLT_366_7	523,605	390,990	-	-	914,595	12,694	3,477	-	-	16,172
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGTT	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	1,774,160	METERS	-	1,118,820	-	-	1,118,820	-	11,147	-	-	11,147
587	CUSTOMER INSTALLATION EXPENSE	1,484,627	PLT_369	-	1,121,824	-	-	1,121,824	-	9,977	-	-	9,977
588	MISC. DISTRIBUTION EXPENSE	2,505,643	DPLT	704,498	975,604	-	-	1,680,103	17,080	8,743	-	-	25,823
589	RENTS	-	DPLT	-	-	-	-	-	-	-	-	-	-
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-
	Sub-total	21,105,928		4,971,972	9,841,562	-	-	14,813,535	120,541	88,964	-	-	209,505
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	-	PLT_360_2	-	-	-	-	-	-	-	-	-	-
592	STATION EQUIPMENT	1,261,242	PLT_360_2	515,689	259,069	-	-	774,758	12,502	2,314	-	-	14,817
593	OVERHEAD LINES	9,796,738	PLT_364_5	2,674,071	4,400,300	-	-	7,074,372	64,831	39,134	-	-	103,964
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-
594	UNDERGROUND LINES	55,053	PLT_366_7	20,409	15,240	-	-	35,649	495	136	-	-	630
594.3 & 594.6	UNDERGROUND LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
594.3 & 594.6	UNDERGROUND LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - DEMAND	-	SEC_DEM	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - CUSTOMER	-	SEC_CUST	-	-	-	-	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	739,646	STTRLGTT	-	-	-	-	-	-	-	-	-	-
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	112,216	DPLT	31,551	43,693	-	-	75,244	765	392	-	-	1,157
	Sub-total	11,964,895		3,241,721	4,718,302	-	-	7,960,023	78,593	41,975	-	-	120,568
	Total Distribution	33,070,822		8,213,693	14,559,864	-	-	22,773,557	199,134	130,940	-	-	330,073
Customer Account													
901	SUPERVISION	3,084,792	CUSTACCTLBR	-	2,667,591	-	-	2,667,591	-	23,724	-	-	23,724
902	METER READING	1,205,576	MTREAD	-	1,043,675	-	-	1,043,675	-	9,282	-	-	9,282
903CR	CUSTOMER RECORDS	15,198,749	CUST	-	13,142,068	-	-	13,142,068	-	116,878	-	-	116,878
903CE	COLLECTION EXPENSES	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080	CUST	-	127,177	-	-	127,177	-	1,131	-	-	1,131
	Sub-total	19,636,197		-	16,980,511	-	-	16,980,511	-	151,015	-	-	151,015
Customer Service & Information Expenses													
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759	CUST	-	9,075,482	-	-	9,075,482	-	80,712	-	-	80,712
	Sub-total	10,495,759		-	9,075,482	-	-	9,075,482	-	80,712	-	-	80,712
Sales Expenses													
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-
	TOTAL O & M LABOR EXP.	63,202,778		8,213,693	40,615,858	-	-	48,829,551	199,134	362,667	-	-	561,801

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	2,531,568	DISTOPLBR	62,143	156,527	-	-	218,670	263,856	94,418	-	-	358,274
581	LOAD DISPATCHING	205,354	PLT_360_2	8,749	5,043	-	-	13,792	37,149	1,922	-	-	39,071
582	STATION EXPENSES	63,106	PLT_360_2	2,689	1,550	-	-	4,238	11,416	591	-	-	12,007
583	OVERHEAD LINES	11,129,059	PLT_364_5	316,540	566,748	-	-	883,288	1,344,014	153,156	-	-	1,497,170
584	UNDERGROUND LINES	1,412,410	PLT_366_7	54,561	44,330	-	-	98,891	231,663	11,980	-	-	243,643
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	1,774,160	METERS	-	203,224	-	-	203,224	-	311,069	-	-	311,069
587	CUSTOMER INSTALLATION EXPENSE	1,484,627	PLT_369	-	200,805	-	-	200,805	-	150,010	-	-	150,010
588	MISC. DISTRIBUTION EXPENSE	2,505,643	DPLT	73,411	126,756	-	-	200,166	311,698	64,026	-	-	375,724
589	RENTS	-	DPLT	-	-	-	-	-	-	-	-	-	-
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-
	Sub-total	21,105,928		518,092	1,304,983	-	-	1,823,075	2,199,796	787,172	-	-	2,986,968
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	-	PLT_360_2	-	-	-	-	-	-	-	-	-	-
592	STATION EQUIPMENT	1,261,242	PLT_360_2	53,736	30,974	-	-	84,710	228,161	11,805	-	-	239,966
593	OVERHEAD LINES	9,796,738	PLT_364_5	278,645	498,900	-	-	777,545	1,183,114	134,821	-	-	1,317,936
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-
594	UNDERGROUND LINES	55,053	PLT_366_7	2,127	1,728	-	-	3,855	9,030	467	-	-	9,497
594.3 & 594.6	UNDERGROUND LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
594.3 & 594.6	UNDERGROUND LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - DEMAND	-	SEC_DEM	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - CUSTOMER	-	SEC_CUST	-	-	-	-	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	739,646	STTRLGT	-	-	-	-	-	-	-	-	-	-
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	112,216	DPLT	3,288	5,677	-	-	8,964	13,959	2,867	-	-	16,827
	Sub-total	11,964,895		337,796	537,279	-	-	875,074	1,434,265	149,961	-	-	1,584,226
	Total Distribution	33,070,822		855,888	1,842,262	-	-	2,698,150	3,634,061	937,132	-	-	4,571,193
Customer Account													
901	SUPERVISION	3,084,792	CUSTACCTLBR	-	302,448	-	-	302,448	-	81,732	-	-	81,732
902	METER READING	1,205,576	MTREAD	-	118,330	-	-	118,330	-	31,977	-	-	31,977
903CR	CUSTOMER RECORDS	15,198,749	CUST	-	1,490,029	-	-	1,490,029	-	402,661	-	-	402,661
903CE	COLLECTION EXPENSES	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080	CUST	-	14,419	-	-	14,419	-	3,897	-	-	3,897
	Sub-total	19,636,197		-	1,925,226	-	-	1,925,226	-	520,267	-	-	520,267
Customer Service & Information Expenses													
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759	CUST	-	1,028,965	-	-	1,028,965	-	278,064	-	-	278,064
	Sub-total	10,495,759		-	1,028,965	-	-	1,028,965	-	278,064	-	-	278,064
Sales Expenses													
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-
	TOTAL O & M LABOR EXP.	63,202,778		855,888	4,796,454	-	-	5,652,342	3,634,061	1,735,463	-	-	5,369,525

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Distribution Operation Expenses															
580	SUPERVISION AND ENGINEERING	2,531,568	DISTOPLBR	116,466	12,744	-	-	129,210	-	5,946	-	-	-	-	5,946
581	LOAD DISPATCHING	205,354	PLT_360_2	21,855	151	-	-	22,006	-	61	-	-	-	-	61
582	STATION EXPENSES	63,106	PLT_360_2	6,716	46	-	-	6,763	-	19	-	-	-	-	19
583	OVERHEAD LINES	11,129,059	PLT_364_5	553,564	3,512	-	-	557,076	-	-	-	-	-	-	-
584	UNDERGROUND LINES	1,412,410	PLT_366_7	133,872	358	-	-	134,230	-	-	-	-	-	-	-
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	1,774,160	METERS	-	84,223	-	-	84,223	-	41,233	-	-	-	-	41,233
587	CUSTOMER INSTALLATION EXPENSE	1,484,627	PLT_369	-	-	-	-	-	-	-	-	-	-	-	-
588	MISC. DISTRIBUTION EXPENSE	2,505,643	DPLT	138,512	5,216	-	-	143,728	-	2,315	-	-	-	-	2,315
589	RENTS	-	DPLT	-	-	-	-	-	-	-	-	-	-	-	-
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	21,105,928		970,986	106,250	-	-	1,077,236	-	49,574	-	-	-	-	49,574
Distribution Maintenance Expenses															
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	-	PLT_360_2	-	-	-	-	-	-	-	-	-	-	-	-
592	STATION EQUIPMENT	1,261,242	PLT_360_2	134,230	928	-	-	135,158	-	374	-	-	-	-	374
593	OVERHEAD LINES	9,796,738	PLT_364_5	487,294	3,091	-	-	490,385	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-	-	-
594	UNDERGROUND LINES	55,053	PLT_366_7	5,218	14	-	-	5,232	-	-	-	-	-	-	-
594.3 & 594.6	UNDERGROUND LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-	-	-
594.3 & 594.6	UNDERGROUND LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - DEMAND	-	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - CUSTOMER	-	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	739,646	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	112,216	DPLT	6,203	234	-	-	6,437	-	104	-	-	-	-	104
	Sub-total	11,964,895		632,946	4,267	-	-	637,212	-	478	-	-	-	-	478
	Total Distribution	33,070,822		1,603,931	110,516	-	-	1,714,448	-	50,052	-	-	-	-	50,052
Customer Account															
901	SUPERVISION	3,084,792	CUSTACCTLBR	-	2,537	-	-	2,537	-	341	-	-	-	-	341
902	METER READING	1,205,576	MTREAD	-	993	-	-	993	-	133	-	-	-	-	133
903CR	CUSTOMER RECORDS	15,198,749	CUST	-	12,499	-	-	12,499	-	1,679	-	-	-	-	1,679
903CE	COLLECTION EXPENSES	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-	-	-
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080	CUST	-	121	-	-	121	-	16	-	-	-	-	16
	Sub-total	19,636,197		-	16,149	-	-	16,149	-	2,169	-	-	-	-	2,169
Customer Service & Information Expenses															
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759	CUST	-	8,631	-	-	8,631	-	1,159	-	-	-	-	1,159
	Sub-total	10,495,759		-	8,631	-	-	8,631	-	1,159	-	-	-	-	1,159
Sales Expenses															
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL O & M LABOR EXP.	63,202,778		1,603,931	135,297	-	-	1,739,228	-	53,381	-	-	-	-	53,381

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	2,531,568	DISTOPLBR	1,823	1,915	-	-	3,738	2,619	11,159	-	-	13,778
581	LOAD DISPATCHING	205,354	PLT_360_2	257	54	-	-	311	369	1,186	-	-	1,555
582	STATION EXPENSES	63,106	PLT_360_2	79	17	-	-	95	113	365	-	-	478
583	OVERHEAD LINES	11,129,059	PLT_364_5	9,286	5,679	-	-	14,965	13,340	8,655	-	-	21,995
584	UNDERGROUND LINES	1,412,410	PLT_366_7	1,601	444	-	-	2,045	2,299	536	-	-	2,835
585	STREET LIGHTING & SIGNAL SYSTEMS	-	STTRLGT	-	-	-	-	-	-	-	-	-	-
586	METER EXPENSE	1,774,160	METERS	-	4,443	-	-	4,443	-	-	-	-	-
587	CUSTOMER INSTALLATION EXPENSE	1,484,627	PLT_369	-	2,012	-	-	2,012	-	-	-	-	-
588	MISC. DISTRIBUTION EXPENSE	2,505,643	DPLT	2,154	1,405	-	-	3,558	3,094	71,132	-	-	74,225
589	RENTS	-	DPLT	-	-	-	-	-	-	-	-	-	-
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-	-	-	-
	Sub-total	21,105,928		15,199	15,969	-	-	31,168	21,835	93,032	-	-	114,867
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-	-	-	-	-
591	STRUCTURES	-	PLT_360_2	-	-	-	-	-	-	-	-	-	-
592	STATION EQUIPMENT	1,261,242	PLT_360_2	1,576	331	-	-	1,908	2,265	7,286	-	-	9,551
593	OVERHEAD LINES	9,796,738	PLT_364_5	8,175	4,999	-	-	13,174	11,743	7,619	-	-	19,362
593.5	OVERHEAD LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-
594	UNDERGROUND LINES	55,053	PLT_366_7	62	17	-	-	80	90	21	-	-	111
594.3 & 594.6	UNDERGROUND LINES - SERVICES - DEMAND	-	SRV_DEM	-	-	-	-	-	-	-	-	-	-
594.3 & 594.6	UNDERGROUND LINES - SERVICES - CUSTOMER	-	SERV	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - DEMAND	-	SEC_DEM	-	-	-	-	-	-	-	-	-	-
595	LINE TRANSFORMERS - CUSTOMER	-	SEC_CUST	-	-	-	-	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	739,646	STTRLGT	-	-	-	-	-	-	739,646	-	-	739,646
597	METERS	-	METERS	-	-	-	-	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	112,216	DPLT	96	63	-	-	159	139	3,186	-	-	3,324
	Sub-total	11,964,895		9,910	5,410	-	-	15,320	14,236	757,757	-	-	771,994
	Total Distribution	33,070,822		25,109	21,379	-	-	46,488	36,071	850,789	-	-	886,860
Customer Account													
901	SUPERVISION	3,084,792	CUSTACCTLBR	-	3,030	-	-	3,030	-	3,388	-	-	3,388
902	METER READING	1,205,576	MTREAD	-	1,186	-	-	1,186	-	-	-	-	-
903CR	CUSTOMER RECORDS	15,198,749	CUST	-	14,930	-	-	14,930	-	18,005	-	-	18,005
903CE	COLLECTION EXPENSES	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	-	TOTDPLT	-	-	-	-	-	-	-	-	-	-
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080	CUST	-	144	-	-	144	-	174	-	-	174
	Sub-total	19,636,197		-	19,290	-	-	19,290	-	21,568	-	-	21,568
Customer Service & Information Expenses													
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	CUST	-	-	-	-	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759	CUST	-	10,310	-	-	10,310	-	12,434	-	-	12,434
	Sub-total	10,495,759		-	10,310	-	-	10,310	-	12,434	-	-	12,434
Sales Expenses													
911-916	SALES EXPENSES	-	CUST	-	-	-	-	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-	-	-	-	-
	TOTAL O & M LABOR EXP.	63,202,778		25,109	50,979	-	-	76,089	36,071	884,791	-	-	920,862

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Depreciation Expense													
Distribution Plant													
360	LAND AND LAND RIGHTS	756,214	PLT_360	212,621	294,442	-	-	507,062	5,155	2,639	-	-	7,794
361	STRUCTURES & IMPROVEMENTS	814,601	PLT_360_1	305,134	203,120	-	-	508,254	7,398	1,820	-	-	9,218
362	STATION EQUIPMENT	20,033,725	PLT_362	8,269,428	4,014,929	-	-	12,284,357	200,485	35,850	-	-	236,335
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	66,278,524	LABOR	8,613,410	42,592,417	-	-	51,205,827	208,825	380,316	-	-	589,141
364	POLES TOWERS & FIXTURES	42,177,610	PLT_364	7,953,104	24,089,218	-	-	32,042,322	192,816	214,236	-	-	407,052
365	OVERHEAD CONDUCTORS	45,318,655	PLT_365	16,067,111	15,011,636	-	-	31,078,747	389,533	133,505	-	-	523,038
366	UNDERGROUND CONDUIT	5,484,850	PLT_366	2,033,328	1,518,343	-	-	3,551,671	49,296	13,503	-	-	62,800
367	UNDERGROUND CONDUCTORS	17,061,472	PLT_367	6,324,980	4,723,039	-	-	11,048,019	153,344	42,004	-	-	195,348
368	LINE TRANSFORMERS - DEMAND	14,566,138	SEC_DEM	9,228,802	-	-	-	9,228,802	223,744	-	-	-	223,744
368	LINE TRANSFORMERS - CUSTOMER	8,605,018	SEC_CUST	-	7,447,542	-	-	7,447,542	-	66,234	-	-	66,234
369	SERVICES	9,866,936	SERV	-	7,455,719	-	-	7,455,719	-	66,307	-	-	66,307
370	METERS	26,031,923	METERS	-	16,416,244	-	-	16,416,244	-	163,563	-	-	163,563
371	INSTALLATIONS ON CUST PREMISES	476,054	AREALGT	-	-	-	-	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971	STTRLGT	-	-	-	-	-	-	-	-	-	-
387	ENERGY STORAGE EQUIPMENT	42,520	TOTDPLT	11,955	16,556	-	-	28,511	290	148	-	-	438
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000	LABOR	237,303	1,173,438	-	-	1,410,741	5,753	10,478	-	-	16,231
	Sub-total	264,935,209		59,257,176	124,956,643	-	-	184,213,819	1,436,638	1,130,605	-	-	2,567,243
General Plant Plant													
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699	LABOR	7,696,191	38,056,864	-	-	45,753,055	186,587	339,818	-	-	526,405
389-399	GENERAL PLANT - PRO FORMA	-	LABOR	-	-	-	-	-	-	-	-	-	-
	Sub-total	59,220,699		7,696,191	38,056,864	-	-	45,753,055	186,587	339,818	-	-	526,405
	TOTAL DEPRECIATION EXPENSES	324,155,908		66,953,367	163,013,507	-	-	229,966,874	1,623,225	1,470,423	-	-	3,093,648

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	16	17	18	19	20	23	24	25	26	27	28	31
				Small General Service - Sec. Voltage					Large General Service - Sec. Voltage						
				GS-1					GS-3						
				DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL		
Depreciation Expense															
Distribution Plant															
360	LAND AND LAND RIGHTS	756,214	PLT_360	22,156	38,255	-	-	60,411		94,072	19,323	-	-	113,395	
361	STRUCTURES & IMPROVEMENTS	814,601	PLT_360_1	31,796	26,390	-	-	58,186		135,003	13,330	-	-	148,333	
362	STATION EQUIPMENT	20,033,725	PLT_362	861,696	474,136	-	-	1,335,831		3,658,720	171,553	-	-	3,830,273	
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	66,278,524	LABOR	897,539	5,029,872	-	-	5,927,411		3,810,912	1,819,919	-	-	5,630,831	
364	POLES TOWERS & FIXTURES	42,177,610	PLT_364	828,734	2,731,201	-	-	3,559,935		3,518,766	738,071	-	-	4,256,837	
365	OVERHEAD CONDUCTORS	45,318,655	PLT_365	1,674,234	1,701,998	-	-	3,376,232		7,108,722	459,942	-	-	7,568,665	
366	UNDERGROUND CONDUIT	5,484,850	PLT_366	211,878	172,148	-	-	384,026		899,624	46,521	-	-	946,145	
367	UNDERGROUND CONDUCTORS	17,061,472	PLT_367	659,079	535,492	-	-	1,194,571		2,798,420	144,709	-	-	2,943,129	
368	LINE TRANSFORMERS - DEMAND	14,566,138	SEC_DEM	961,665	-	-	-	961,665		4,083,185	-	-	-	4,083,185	
368	LINE TRANSFORMERS - CUSTOMER	8,605,018	SEC_CUST	-	844,392	-	-	844,392		-	228,186	-	-	228,186	
369	SERVICES	9,866,936	SERV	-	1,334,564	-	-	1,334,564		-	996,974	-	-	996,974	
370	METERS	26,031,923	METERS	-	2,981,868	-	-	2,981,868		-	4,564,264	-	-	4,564,264	
371	INSTALLATIONS ON CUST PREMISES	476,054	AREALGT	-	-	-	-	-		-	-	-	-	-	
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971	STTRLGT	-	-	-	-	-		-	-	-	-	-	
387	ENERGY STORAGE EQUIPMENT	42,520	TOTDPLT	1,246	2,151	-	-	3,397		5,289	1,087	-	-	6,376	
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000	LABOR	24,728	138,575	-	-	163,303		104,992	50,140	-	-	155,132	
	Sub-total	264,935,209		6,174,750	16,011,041	-	-	22,185,791		26,217,706	9,254,020	-	-	35,471,726	
General Plant Plant															
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699	LABOR	801,963	4,494,254	-	-	5,296,217		3,405,098	1,626,121	-	-	5,031,219	
389-399	GENERAL PLANT - PRO FORMA	-	LABOR	-	-	-	-	-		-	-	-	-	-	
	Sub-total	59,220,699		801,963	4,494,254	-	-	5,296,217		3,405,098	1,626,121	-	-	5,031,219	
	TOTAL DEPRECIATION EXPENSES	324,155,908		6,976,713	20,505,295	-	-	27,482,008		29,622,804	10,880,140	-	-	40,502,945	

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Depreciation Expense															
Distribution Plant															
360	LAND AND LAND RIGHTS	756,214	PLT_360	41,804	1,574	-	-	43,378	-	699	-	-	-	-	699
361	STRUCTURES & IMPROVEMENTS	814,601	PLT_360_1	71,666	1,086	-	-	72,752	-	482	-	-	-	-	482
362	STATION EQUIPMENT	20,033,725	PLT_362	2,174,180	13,374	-	-	2,187,554	-	5,277	-	-	-	-	5,277
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	66,278,524	LABOR	1,681,986	141,881	-	-	1,823,868	-	55,978	-	-	-	-	55,978
364	POLES TOWERS & FIXTURES	42,177,610	PLT_364	1,762,438	15,487	-	-	1,777,925	-	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS	45,318,655	PLT_365	2,602,637	12,038	-	-	2,614,676	-	-	-	-	-	-	-
366	UNDERGROUND CONDUIT	5,484,850	PLT_366	519,870	1,389	-	-	521,259	-	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS	17,061,472	PLT_367	1,617,136	4,320	-	-	1,621,457	-	-	-	-	-	-	-
368	LINE TRANSFORMERS - DEMAND	14,566,138	SEC_DEM	-	-	-	-	-	-	-	-	-	-	-	-
368	LINE TRANSFORMERS - CUSTOMER	8,605,018	SEC_CUST	-	-	-	-	-	-	-	-	-	-	-	-
369	SERVICES	9,866,936	SERV	-	-	-	-	-	-	-	-	-	-	-	-
370	METERS	26,031,923	METERS	-	1,235,783	-	-	1,235,783	-	605,008	-	-	-	-	605,008
371	INSTALLATIONS ON CUST PREMISES	476,054	AREALGT	-	-	-	-	-	-	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971	STTRLGT	-	-	-	-	-	-	-	-	-	-	-	-
387	ENERGY STORAGE EQUIPMENT	42,520	TOTDPLT	2,351	89	-	-	2,439	-	39	-	-	-	-	39
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000	LABOR	46,339	3,909	-	-	50,248	-	1,542	-	-	-	-	1,542
	Sub-total	264,935,209		10,520,407	1,430,931	-	-	11,951,338	-	669,025	-	-	-	-	669,025
General Plant Plant															
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699	LABOR	1,502,876	126,773	-	-	1,629,649	-	50,017	-	-	-	-	50,017
389-399	GENERAL PLANT - PRO FORMA	-	LABOR	-	-	-	-	-	-	-	-	-	-	-	-
	Sub-total	59,220,699		1,502,876	126,773	-	-	1,629,649	-	50,017	-	-	-	-	50,017
TOTAL DEPRECIATION EXPENSES		324,155,908		12,023,283	1,557,704	-	-	13,580,987	-	719,042	-	-	-	-	719,042

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Depreciation Expense													
Distribution Plant													
360	LAND AND LAND RIGHTS	756,214	PLT_360	650	424	-	-	1,074	934	21,468	-	-	22,402
361	STRUCTURES & IMPROVEMENTS	814,601	PLT_360_1	933	292	-	-	1,225	1,340	14,810	-	-	16,150
362	STATION EQUIPMENT	20,033,725	PLT_362	25,280	5,039	-	-	30,319	36,316	87,463	-	-	123,778
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQL	66,278,524	LABOR	26,331	53,460	-	-	79,792	37,826	927,849	-	-	965,675
364	POLES TOWERS & FIXTURES	42,177,610	PLT_364	24,313	27,366	-	-	51,679	34,927	46,932	-	-	81,858
365	OVERHEAD CONDUCTORS	45,318,655	PLT_365	49,117	17,054	-	-	66,171	70,560	20,567	-	-	91,126
366	UNDERGROUND CONDUIT	5,484,850	PLT_366	6,216	1,725	-	-	7,941	8,929	2,080	-	-	11,010
367	UNDERGROUND CONDUCTORS	17,061,472	PLT_367	19,336	5,366	-	-	24,701	27,777	6,471	-	-	34,247
368	LINE TRANSFORMERS - DEMAND	14,566,138	SEC_DEM	28,213	-	-	-	28,213	40,529	-	-	-	40,529
368	LINE TRANSFORMERS - CUSTOMER	8,605,018	SEC_CUST	-	8,461	-	-	8,461	-	10,204	-	-	10,204
369	SERVICES	9,866,936	SERV	-	13,372	-	-	13,372	-	-	-	-	-
370	METERS	26,031,923	METERS	-	65,192	-	-	65,192	-	-	-	-	-
371	INSTALLATIONS ON CUST PREMISES	476,054	AREALGT	-	-	-	-	-	-	476,054	-	-	476,054
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971	STTRLGT	-	-	-	-	-	-	5,594,971	-	-	5,594,971
387	ENERGY STORAGE EQUIPMENT	42,520	TOTDPLT	37	24	-	-	60	53	1,207	-	-	1,260
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000	LABOR	725	1,473	-	-	2,198	1,042	25,563	-	-	26,605
	Sub-total	264,935,209		181,150	199,249	-	-	380,399	260,231	7,235,636	-	-	7,495,868
General Plant Plant													
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699	LABOR	23,527	47,767	-	-	71,295	33,798	829,045	-	-	862,843
389-399	GENERAL PLANT - PRO FORMA	-	LABOR	-	-	-	-	-	-	-	-	-	-
	Sub-total	59,220,699		23,527	47,767	-	-	71,295	33,798	829,045	-	-	862,843
TOTAL DEPRECIATION EXPENSES		324,155,908		204,677	247,016	-	-	451,693	294,030	8,064,681	-	-	8,358,711

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Taxes Other Than Income Taxes													
TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)	DPLT	(707,129)	(979,248)	-	-	(1,686,377)	(17,144)	(8,776)	-	-	(25,920)
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)	TOTPLT	(27,073)	(42,405)	-	-	(69,478)	(656)	(380)	-	-	(1,036)
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000	DPLT	7,271,763	10,070,092	-	-	17,341,856	176,297	90,249	-	-	266,547
TAX	DEFERRED TAXES - LABOR	23,224,000	LABOR	3,018,140	14,924,386	-	-	17,942,526	73,172	133,263	-	-	206,435
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000	TOTPLT	652,936	1,022,702	-	-	1,675,638	15,830	9,160	-	-	24,990
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000	TOTPLT	398,132	623,599	-	-	1,021,731	9,652	5,585	-	-	15,238
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)	DPLT	(4,217)	(5,840)	-	-	(10,058)	(102)	(52)	-	-	(155)
TAX	OTHER TAXES - LABOR	4,862,000	LABOR	631,855	3,124,456	-	-	3,756,311	15,319	27,899	-	-	43,218
TAX	GROSS RECEIPTS TAX	56,151,000	TOTPLT	14,903,665	23,343,802	-	-	38,247,467	361,326	209,086	-	-	570,413
TAX	GROSS RECEIPTS TAX - INCREASE	22,406,453	TOTPLT	5,947,147	9,315,093	-	-	15,262,241	144,183	83,434	-	-	227,617
	Sub-total	133,834,453		32,085,219	61,396,639	-	-	93,481,857	777,878	549,469	-	-	1,327,346
		-											
	TOTAL TAXES OTHER THAN INCOME TAX	133,834,453		32,085,219	61,396,639	-	-	93,481,857	777,878	549,469	-	-	1,327,346
Adjustments to Taxable Income													
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)	TOTPLT	(54,007,638)	(84,592,857)	-	-	(138,600,495)	(1,309,367)	(757,683)	-	-	(2,067,051)
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000	DEPR	1,065,782	2,594,892	-	-	3,660,674	25,839	23,407	-	-	49,246
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000	DEPR_DPLT	9,670,005	20,391,308	-	-	30,061,313	234,441	184,500	-	-	418,941
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)	DEPR_GIPLT	(12,330,005)	(60,970,591)	-	-	(73,300,596)	(298,930)	(544,419)	-	-	(843,349)
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000	DPLT	105,718	146,400	-	-	252,118	2,563	1,312	-	-	3,875
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000	LABOR	1,982,116	9,801,358	-	-	11,783,474	48,055	87,518	-	-	135,573
	Sub-total	(234,334,000)		(53,514,023)	(112,629,489)	-	-	(166,143,512)	(1,297,400)	(1,005,365)	-	-	(2,302,765)
PA Special Deductions													
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELATED	(33,338,000)	DEPR_DPLT	(7,456,599)	(15,723,862)	-	-	(23,180,461)	(180,779)	(142,269)	-	-	(323,048)
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)	DPLT	(253,048)	(350,427)	-	-	(603,475)	(6,135)	(3,141)	-	-	(9,275)
TAX	FEDEARL TAX CREDIT - DIST	(900,000)	DPLT	(253,048)	(350,427)	-	-	(603,475)	(6,135)	(3,141)	-	-	(9,275)
	TOTAL	(35,138,000)	0	(7,962,696)	(16,424,715)	-	-	(24,387,411)	(193,049)	(148,550)	-	-	(341,599)
Net Adds/Deducts to Taxable Income													
		(269,472,000)	0	(61,476,719)	(129,054,204)	-	-	(190,530,923)	(1,490,449)	(1,153,915)	-	-	(2,644,364)

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	16	17	18	19	20	23	24	25	26	27	28	31
				Small General Service - Sec. Voltage					Large General Service - Sec. Voltage						
				GS-1					GS-3						
				DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL		
Taxes Other Than Income Taxes															
TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)	DPLT	(73,685)	(127,229)	-	-	(200,914)	(312,862)	(64,265)	-	-	-	(377,127)	
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)	TOTPLT	(2,821)	(5,429)	-	-	(8,250)	(11,978)	(2,627)	-	-	-	(14,605)	
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000	DPLT	757,736	1,308,359	-	-	2,066,095	3,217,314	660,870	-	-	-	3,878,184	
TAX	DEFERRED TAXES - LABOR	23,224,000	LABOR	314,498	1,762,467	-	-	2,076,965	1,335,344	637,700	-	-	-	1,973,044	
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000	TOTPLT	68,038	130,927	-	-	198,965	288,885	63,348	-	-	-	352,232	
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000	TOTPLT	41,486	79,834	-	-	121,320	176,149	38,627	-	-	-	214,776	
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)	DPLT	(439)	(759)	-	-	(1,198)	(1,866)	(383)	-	-	-	(2,249)	
TAX	OTHER TAXES - LABOR	4,862,000	LABOR	65,841	368,977	-	-	434,818	279,557	133,504	-	-	-	413,061	
TAX	GROSS RECEIPTS TAX	56,151,000	TOTPLT	1,553,000	2,988,495	-	-	4,541,495	6,593,968	1,445,953	-	-	-	8,039,921	
TAX	GROSS RECEIPTS TAX - INCREASE	22,406,453	TOTPLT	619,708	1,192,527	-	-	1,812,235	2,631,252	576,992	-	-	-	3,208,244	
	Sub-total	133,834,453		3,343,362	7,698,169	-	-	11,041,531	14,195,763	3,489,718	-	-	-	17,685,482	
	TOTAL TAXES OTHER THAN INCOME TAX	133,834,453		3,343,362	7,698,169	-	-	11,041,531	14,195,763	3,489,718	-	-	-	17,685,482	
Adjustments to Taxable Income															
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)	TOTPLT	(5,627,735)	(10,829,654)	-	-	(16,457,389)	(23,895,104)	(5,239,819)	-	-	-	(29,134,923)	
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000	DEPR	111,057	326,409	-	-	437,466	471,544	173,193	-	-	-	644,737	
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000	DEPR_DPLT	1,007,639	2,612,795	-	-	3,620,434	4,278,391	1,510,136	-	-	-	5,788,527	
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)	DEPR_GIPLT	(1,284,818)	(7,200,208)	-	-	(8,485,026)	(5,455,279)	(2,605,195)	-	-	-	(8,060,475)	
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000	DPLT	11,016	19,021	-	-	30,037	46,774	9,608	-	-	-	56,382	
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000	LABOR	206,542	1,157,473	-	-	1,364,015	876,966	418,799	-	-	-	1,295,766	
	Sub-total	(234,334,000)		(5,576,299)	(13,914,164)	-	-	(19,490,463)	(23,676,709)	(5,733,278)	-	-	-	(29,409,987)	
PA Special Deductions															
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELATED	(33,338,000)	DEPR_DPLT	(776,997)	(2,014,742)	-	-	(2,791,739)	(3,299,093)	(1,164,475)	-	-	-	(4,463,568)	
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)	DPLT	(26,368)	(45,529)	-	-	(71,898)	(111,959)	(22,997)	-	-	-	(134,956)	
TAX	FEDEARL TAX CREDIT - DIST	(900,000)	DPLT	(26,368)	(45,529)	-	-	(71,898)	(111,959)	(22,997)	-	-	-	(134,956)	
	TOTAL	(35,138,000)	0	(829,733)	(2,105,800)	-	-	(2,935,534)	(3,523,010)	(1,210,470)	-	-	-	(4,733,480)	
Net Adds/Deducts to Taxable Income		(269,472,000)	0	(6,406,032)	(16,019,964)	-	-	(22,425,996)	(27,199,719)	(6,943,748)	-	-	-	(34,143,467)	

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	~	~	TOTAL
Taxes Other Than Income Taxes															
TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)	DPLT	(139,029)	(5,235)	-	-	(144,265)	-	(2,323)	-	-	-	-	(2,323)
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)	TOTPLT	(5,321)	(213)	-	-	(5,534)	-	(93)	-	-	-	-	(93)
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000	DPLT	1,429,709	53,839	-	-	1,483,548	-	23,892	-	-	-	-	23,892
TAX	DEFERRED TAXES - LABOR	23,224,000	LABOR	589,368	49,715	-	-	639,083	-	19,615	-	-	-	-	19,615
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000	TOTPLT	128,330	5,136	-	-	133,466	-	2,252	-	-	-	-	2,252
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000	TOTPLT	78,250	3,132	-	-	81,382	-	1,373	-	-	-	-	1,373
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)	DPLT	(829)	(31)	-	-	(860)	-	(14)	-	-	-	-	(14)
TAX	OTHER TAXES - LABOR	4,862,000	LABOR	123,386	10,408	-	-	133,794	-	4,106	-	-	-	-	4,106
TAX	GROSS RECEIPTS TAX	56,151,000	TOTPLT	2,929,211	117,234	-	-	3,046,445	-	51,409	-	-	-	-	51,409
TAX	GROSS RECEIPTS TAX - INCREASE	22,406,453	TOTPLT	1,168,870	46,781	-	-	1,215,651	-	20,514	-	-	-	-	20,514
	Sub-total	133,834,453		6,301,944	280,765	-	-	6,582,709	-	120,732	-	-	-	-	120,732
	TOTAL TAXES OTHER THAN INCOME TAX	133,834,453		6,301,944	280,765	-	-	6,582,709	-	120,732	-	-	-	-	120,732
Adjustments to Taxable Income															
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)	TOTPLT	(10,614,823)	(424,830)	-	-	(11,039,653)	-	(186,295)	-	-	-	-	(186,295)
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000	DEPR	191,390	24,796	-	-	216,186	-	11,446	-	-	-	-	11,446
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000	DEPR_DPLT	1,716,794	233,509	-	-	1,950,304	-	109,176	-	-	-	-	109,176
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)	DEPR_GIPLT	(2,407,745)	(203,102)	-	-	(2,610,847)	-	(80,132)	-	-	-	-	(80,132)
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000	DPLT	20,785	783	-	-	21,568	-	347	-	-	-	-	347
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000	LABOR	387,058	32,650	-	-	419,708	-	12,882	-	-	-	-	12,882
	Sub-total	(234,334,000)		(10,706,540)	(336,194)	-	-	(11,042,734)	-	(132,576)	-	-	-	-	(132,576)
PA Special Deductions															
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELATED	(33,338,000)	DEPR_DPLT	(1,323,831)	(180,061)	-	-	(1,503,891)	-	(84,186)	-	-	-	-	(84,186)
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)	DPLT	(49,752)	(1,874)	-	-	(51,626)	-	(831)	-	-	-	-	(831)
TAX	FEDEARL TAX CREDIT - DIST	(900,000)	DPLT	(49,752)	(1,874)	-	-	(51,626)	-	(831)	-	-	-	-	(831)
	TOTAL	(35,138,000)	0	(1,423,335)	(183,808)	-	-	(1,607,142)	-	(85,849)	-	-	-	-	(85,849)
Net Adds/Deducts to Taxable Income		(269,472,000)	0	(12,129,875)	(520,001)	-	-	(12,649,876)	-	(218,425)	-	-	-	-	(218,425)

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Taxes Other Than Income Taxes													
TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)	DPLT	(2,162)	(1,410)	-	-	(3,572)	(3,105)	(71,397)	-	-	(74,503)
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)	TOTPLT	(83)	(60)	-	-	(143)	(119)	(2,743)	-	-	(2,862)
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000	DPLT	22,230	14,500	-	-	36,730	31,934	734,214	-	-	766,148
TAX	DEFERRED TAXES - LABOR	23,224,000	LABOR	9,226	18,733	-	-	27,959	13,254	325,118	-	-	338,373
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000	TOTPLT	1,996	1,442	-	-	3,438	2,867	66,150	-	-	69,018
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000	TOTPLT	1,217	879	-	-	2,096	1,748	40,336	-	-	42,084
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)	DPLT	(13)	(8)	-	-	(21)	(19)	(426)	-	-	(444)
TAX	OTHER TAXES - LABOR	4,862,000	LABOR	1,932	3,922	-	-	5,853	2,775	68,064	-	-	70,839
TAX	GROSS RECEIPTS TAX	56,151,000	TOTPLT	45,561	32,918	-	-	78,479	65,450	1,509,921	-	-	1,575,371
TAX	GROSS RECEIPTS TAX - INCREASE	22,406,453	TOTPLT	18,181	13,136	-	-	31,316	26,117	602,518	-	-	628,635
	Sub-total	133,834,453		98,085	84,052	-	-	182,137	140,904	3,271,755	-	-	3,412,659
	TOTAL TAXES OTHER THAN INCOME TAX	133,834,453		98,085	84,052	-	-	182,137	140,904	3,271,755	-	-	3,412,659
Adjustments to Taxable Income													
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)	TOTPLT	(165,102)	(119,289)	-	-	(284,392)	(237,178)	(5,471,625)	-	-	(5,708,803)
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000	DEPR	3,258	3,932	-	-	7,190	4,680	128,376	-	-	133,056
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000	DEPR_DPLT	29,561	32,515	-	-	62,076	42,466	1,180,762	-	-	1,223,229
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)	DEPR_GIPLT	(37,693)	(76,528)	-	-	(114,221)	(54,148)	(1,328,206)	-	-	(1,382,354)
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000	DPLT	323	211	-	-	534	464	10,674	-	-	11,138
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000	LABOR	6,059	12,302	-	-	18,362	8,705	213,516	-	-	222,221
	Sub-total	(234,334,000)		(163,593)	(146,857)	-	-	(310,450)	(235,010)	(5,266,503)	-	-	(5,501,513)
PA Special Deductions													
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELATED	(33,338,000)	DEPR_DPLT	(22,795)	(25,072)	-	-	(47,867)	(32,746)	(910,493)	-	-	(943,239)
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)	DPLT	(774)	(505)	-	-	(1,278)	(1,111)	(25,550)	-	-	(26,661)
TAX	FEDEARL TAX CREDIT - DIST	(900,000)	DPLT	(774)	(505)	-	-	(1,278)	(1,111)	(25,550)	-	-	(26,661)
	TOTAL	(35,138,000)	0	(24,342)	(26,081)	-	-	(50,424)	(34,969)	(961,592)	-	-	(996,561)
Net Adds/Deducts to Taxable Income													
		(269,472,000)	0	(187,935)	(172,939)	-	-	(360,874)	(269,979)	(6,228,095)	-	-	(6,498,074)

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

Account Description		Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Fuel and Purchased Power													
555	PURCHASED POWER	-	FUL_ENRGYSR	-	-	-	-	-	-	-	-	-	-
557	OTHER PURCHASED POWER EXPENSES	323,299	FUL_ENRGYSR	-	-	109,363	-	109,363	-	-	1,777	-	1,777
	TOTAL	323,299	0	-	-	109,363	-	109,363	-	-	1,777	-	1,777
Operating Revenues													
REV	DISTRIBUTION REVENUES	1,004,890,414	REV_DIST	-	-	-	722,241,788	722,241,788	-	-	-	7,972,439	7,972,439
REV	STATE TAX ADJ SURCHARGE	-	REV_STAS	-	-	-	-	-	-	-	-	-	-
REV	LATE PAYMENT CHARGES	15,305,520	LT_FEES	-	-	-	11,428,698	11,428,698	-	-	-	83,895	83,895
REV	ANNUALIZATION	4,932,874	REV_ANNL	-	-	-	3,865,736	3,865,736	-	-	-	(91,936)	(91,936)
REV	MISCELLANEOUS SERVICE REVS	969,910	REV_TOTDPLT	-	-	-	650,351	650,351	-	-	-	9,996	9,996
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268	REV_TOTDPLT	-	-	-	27,377,152	27,377,152	-	-	-	420,791	420,791
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960	REV_TOTDPLT	-	-	-	2,028,319	2,028,319	-	-	-	31,176	31,176
REV	RESALE & BL REVENUES	318,877	REV_DIST	-	-	-	229,185	229,185	-	-	-	2,530	2,530
REV	BL REVENUES	348,811	REV_DIST	-	-	-	250,700	250,700	-	-	-	2,767	2,767
	Sub-total	1,072,319,685	-	-	-	-	769,340,619	769,340,619	-	-	-	8,440,970	8,440,970
	TOTAL	1,072,319,685		-	-	-	769,340,619	769,340,619	-	-	-	8,440,970	8,440,970

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	16	17	18	19	20	23	24	25	26	27	28	31
				Small General Service - Sec. Voltage					Large General Service - Sec. Voltage						
				GS-1					GS-3						
				DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL		
Fuel and Purchased Power															
555	PURCHASED POWER	-	FUL_ENRGYSR	-	-	-	-	-	-	-	-	-	-	-	-
557	OTHER PURCHASED POWER EXPENSES	323,299	FUL_ENRGYSR	-	-	14,232	-	14,232	-	-	-	63,371	-	63,371	-
	TOTAL	323,299	0	-	-	14,232	-	14,232	-	-	-	63,371	-	63,371	-
				-	-	-	-	-	-	-	-	-	-	-	-
Operating Revenues															
REV	DISTRIBUTION REVENUES	1,004,890,414	REV_DIST	-	-	-	78,763,076	78,763,076	-	-	-	129,185,676	129,185,676		
REV	STATE TAX ADJ SURCHARGE	-	REV_STAS	-	-	-	-	-	-	-	-	-	-	-	-
REV	LATE PAYMENT CHARGES	15,305,520	LT_FEES	-	-	-	1,363,531	1,363,531	-	-	-	1,785,597	1,785,597		
REV	ANNUALIZATION	4,932,874	REV_ANNL	-	-	-	20,269	20,269	-	-	-	891,225	891,225		
REV	MISCELLANEOUS SERVICE REVS	969,910	REV_TOTDPLT	-	-	-	77,482	77,482	-	-	-	145,439	145,439		
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268	REV_TOTDPLT	-	-	-	3,261,693	3,261,693	-	-	-	6,122,392	6,122,392		
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960	REV_TOTDPLT	-	-	-	241,652	241,652	-	-	-	453,596	453,596		
REV	RESALE & BL REVENUES	318,877	REV_DIST	-	-	-	24,994	24,994	-	-	-	40,994	40,994		
REV	BL REVENUES	348,811	REV_DIST	-	-	-	27,340	27,340	-	-	-	44,842	44,842		
	Sub-total	1,072,319,685	-	-	-	-	83,931,401	83,931,401	-	-	-	138,867,977	138,867,977		
	TOTAL	1,072,319,685		-	-	-	83,931,401	83,931,401	-	-	-	138,867,977	138,867,977		

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	32	33	34	35	36	39	40	41	42	43	44	45	46	47
				Large General Service - 12 KV						Large General Service - 69 KV or Higher							
				LP-4						LP-5							
				DEM	CUS	FUL	REV	TOTAL		DEM	CUS	FUL	REV	~	~	TOTAL	
Fuel and Purchased Power																	
555	PURCHASED POWER	-	FUL_ENRGYSR	-	-	-	-	-	-	-	-	-	-	-	-	-	-
557	OTHER PURCHASED POWER EXPENSES	323,299	FUL_ENRGYSR	-	-	45,253	-	45,253	-	-	-	88,467	-	-	-	88,467	-
	TOTAL	323,299	0	-	-	45,253	-	45,253	-	-	-	88,467	-	-	-	88,467	-
Operating Revenues																	
REV	DISTRIBUTION REVENUES	1,004,890,414	REV_DIST	-	-	-	38,982,979	38,982,979	-	-	-	-	1,980,048	-	-	1,980,048	-
REV	STATE TAX ADJ SURCHARGE	-	REV_STAS	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REV	LATE PAYMENT CHARGES	15,305,520	LT_FEES	-	-	-	542,576	542,576	-	-	-	-	81,961	-	-	81,961	-
REV	ANNUALIZATION	4,932,874	REV_ANNL	-	-	-	221,023	221,023	-	-	-	-	8,188	-	-	8,188	-
REV	MISCELLANEOUS SERVICE REVS	969,910	REV_TOTDPLT	-	-	-	55,636	55,636	-	-	-	-	896	-	-	896	-
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268	REV_TOTDPLT	-	-	-	2,342,040	2,342,040	-	-	-	-	37,718	-	-	37,718	-
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960	REV_TOTDPLT	-	-	-	173,517	173,517	-	-	-	-	2,794	-	-	2,794	-
REV	RESALE & BL REVENUES	318,877	REV_DIST	-	-	-	12,370	12,370	-	-	-	-	628	-	-	628	-
REV	BL REVENUES	348,811	REV_DIST	-	-	-	13,532	13,532	-	-	-	-	687	-	-	687	-
	Sub-total	1,072,319,685	-	-	-	-	42,403,904	42,403,904	-	-	-	-	2,122,019	-	-	2,122,019	-
	TOTAL	1,072,319,685		-	-	-	42,403,904	42,403,904	-	-	-	-	2,122,019	-	-	2,122,019	-

Allocated Cost of Service Study

Detailed Cost Allocation Results

Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	FUL	REV	TOTAL	DEM	CUS	FUL	REV	TOTAL
Fuel and Purchased Power													
555	PURCHASED POWER	-	FUL_ENRGYSR	-	-	-	-	-	-	-	-	-	-
557	OTHER PURCHASED POWER EXPENSES	323,299	FUL_ENRGYSR	-	-	271	-	271	-	-	565	-	565
	TOTAL	323,299	0	-	-	271	-	271	-	-	565	-	565
Operating Revenues													
REV	DISTRIBUTION REVENUES	1,004,890,414	REV_DIST	-	-	-	1,306,593	1,306,593	-	-	-	24,457,815	24,457,815
REV	STATE TAX ADJ SURCHARGE	-	REV_STAS	-	-	-	-	-	-	-	-	-	-
REV	LATE PAYMENT CHARGES	15,305,520	LT_FEES	-	-	-	19,262	19,262	-	-	-	-	-
REV	ANNUALIZATION	4,932,874	REV_ANNL	-	-	-	(5,140)	(5,140)	-	-	-	23,509	23,509
REV	MISCELLANEOUS SERVICE REVS	969,910	REV_TOTDPLT	-	-	-	1,377	1,377	-	-	-	28,732	28,732
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268	REV_TOTDPLT	-	-	-	57,984	57,984	-	-	-	1,209,499	1,209,499
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960	REV_TOTDPLT	-	-	-	4,296	4,296	-	-	-	89,609	89,609
REV	RESALE & BL REVENUES	318,877	REV_DIST	-	-	-	415	415	-	-	-	7,761	7,761
REV	BL REVENUES	348,811	REV_DIST	-	-	-	454	454	-	-	-	8,490	8,490
	Sub-total	1,072,319,685	-	-	-	-	1,387,379	1,387,379	-	-	-	25,825,415	25,825,415
	TOTAL	1,072,319,685		-	-	-	1,387,379	1,387,379	-	-	-	25,825,415	25,825,415

PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027

SECTION III
COST ALLOCATION TO JURISDICTIONS AT PRESENT RATES

This section shows the allocation to Federal jurisdictional wholesale services and customers supplied on a system cost basis. There are two parts to this section; the first provides a summary of the resulting allocations including rate base, expenses, taxes and return for (1) transmission and (2) PAPUC Jurisdictional. The second part of this section provides details by FERC account including taxes and pro forma adjustments for each of these jurisdictions. This section is organized by several sections as listed: Total Plant, Accumulated Depreciation, Rate Base Adjustments, O&M, Labor (for development of labor allocator), Depreciation Expense, Amortization, Taxes, and Revenues. Further, the results of this section directly feed the account balances used in the Class Cost of Service Study provided in Section II. The functionalization, classification, and allocation that support the results provided in this section are detailed in Section V.

**Jurisdictional Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line No.	Description	System Total	FERC Transmission	PUC Jurisdiction Distribution
			Transmission	Distribution
	(A)	(B)	(C)	(D)
Rate Base				
1	Plant in Service	\$ 20,372,666,945	\$ 10,170,680,034	\$ 10,201,986,912
2	Accumulated Reserve	4,743,703,369	1,487,623,982	3,256,079,387
3	Other Rate Base Items	(2,518,299,546)	(1,393,181,170)	(1,125,118,376)
4	<u>Total Rate Base</u>	<u>\$ 13,110,664,031</u>	<u>\$ 7,289,874,882</u>	<u>\$ 5,820,789,148</u>
Revenues at Current Rates				
5	Transmission	\$ -	\$ -	\$ -
6	Distribution	1,006,589,465	-	1,006,589,465
7	BL Revenues	348,811	-	348,811
8	Sale for Resale	318,877	-	318,877
9	Late Payment Charges	15,305,520	-	15,305,520
10	Annualization	4,932,874	-	4,932,874
11	Other Operating Revenue	1,020,561,414	977,436,326	43,125,088
12	<u>Total Revenues</u>	<u>\$ 2,048,056,960</u>	<u>\$ 977,436,326</u>	<u>\$ 1,070,620,634</u>
Expenses at Current Rates				
13	Transmission O&M	\$ 35,168,630	\$ 35,168,630	\$ -
14	Distribution O&M	204,328,784	(43,381)	204,372,165
15	Fuel and Purchased Power	323,299	-	323,299
16	Amortization Expense	-	-	-
17	Other	264,543,433	38,116,112	226,427,321
18	<u>Total Operations & Maintenance Expenses</u>	<u>\$ 504,364,145</u>	<u>\$ 73,241,361</u>	<u>\$ 431,122,784</u>
Depreciation Expenses				
19	Transmission	224,744,340	224,744,340	-
20	Distribution	264,935,209	-	264,935,209
21	Other	59,721,637	500,938	59,220,699
22	<u>Total Depreciation Expenses</u>	<u>\$ 549,401,186</u>	<u>\$ 225,245,278</u>	<u>\$ 324,155,908</u>
23	<u>Total Expenses (O&M & Depreciation)</u>	<u>\$ 1,053,765,331</u>	<u>\$ 298,486,638</u>	<u>\$ 755,278,692</u>
Taxes				
24	Income Taxes	\$ 13,339,159	\$ 46,600,158	\$ (33,261,000)
25	Gross Receipts Tax	56,151,000	-	56,151,000
26	Taxes Other Than Income Taxes	12,909,000	4,087,000	8,822,000
27	Deferred Income Taxes	136,536,000	90,066,000	46,470,000
28	Investment Tax Credit	(31,000)	(16,000)	(15,000)
29	<u>Total Taxes</u>	<u>\$ 218,904,159</u>	<u>\$ 140,737,158</u>	<u>\$ 78,167,000</u>
30	Current Operating Expenses	1,272,669,489	439,223,797	833,445,693
31	Current Operating Income	775,387,471	538,212,529	237,174,941
32	<u>Return at Current Rates</u>	<u>5.91%</u>	<u>7.38%</u>	<u>4.07%</u>

**Jurisdictional Cost of Service Study
Summary of Results
Fully Projected Future Test Year**

Line No.	Description	System Total	FERC Transmission	PUC Jurisdiction Distribution
			Transmission	Distribution
	(A)	(B)	(C)	(D)
<u>INCOME TAX CALCS @ PRESENT RATES</u>				
<u>Income Tax Calculations</u>				
33	Operating Revenue	\$ 2,048,056,960	\$ 977,436,326	\$ 1,070,620,634
34	Operating Expense	1,053,765,331	298,486,638	755,278,692
35	Gross Receipts Tax	56,151,000	-	56,151,000
36	Taxes Other Than Income Taxes (excl GRT)	12,909,000	4,087,000	8,822,000
37	Taxable Income Before Adjustments	925,231,629	674,862,688	250,368,942
38	Interest Expense	(292,367,808)	(162,564,210)	(129,803,598)
39	Other Adjustment to Taxable Income	(551,426,000)	(317,092,000)	(234,334,000)
40	Adjustment to Taxable Income	(843,793,808)	(479,656,210)	(364,137,598)
41	<u>Taxable Net Income</u>	<u>\$ 81,437,822</u>	<u>\$ 195,206,478</u>	<u>\$ (113,768,656)</u>
<u>PA Income Tax Calculations</u>				
42	Total Taxable Net Income	\$ 81,437,822	\$ 195,206,478	\$ (113,768,656)
43	PA Special Deduction	(124,675,000)	(90,437,000)	(34,238,000)
44	PA Taxable Net Income	(43,237,178)	104,769,478	(148,006,656)
45	<u>PA Income Tax</u>	<u>\$ (2,990,874)</u>	<u>\$ 7,730,124</u>	<u>\$ (10,720,990)</u>
<u>Federal Income Tax Calculations</u>				
46	Total Taxable Net Income	\$ 81,437,822	\$ 195,206,478	\$ (113,768,656)
47	Deduction - PA Income Tax	2,990,874	(7,730,124)	10,720,990
48	Federal Taxable Net Income before NOL	84,428,696	187,476,354	(103,047,667)
49	Federal Net Operating Loss	-	-	-
50	Federal Taxable Net Income after NOL	84,428,696	187,476,354	(103,047,667)
51	Federal Income Tax @ 21.00%	17,730,026	39,370,034	(21,640,010)
52	Federal Tax Credit	(1,400,000)	(500,000)	(900,000)
53	<u>Federal Income Tax</u>	<u>\$ 16,330,026</u>	<u>\$ 38,870,034</u>	<u>\$ (22,540,010)</u>
54	Total Income Tax	\$ 13,339,152	\$ 46,600,158	\$ (33,261,000)

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
RATE BASE									
Plant-in Service									
301-303	Intangible Plant								
	INTANGIBLE PLANT - DISTRIBUTION	670,295	LABOR_NOTRN	-	-	-	-	-	-
	Sub-total	670,295		-	-	-	-	-	-
350-359	Transmission Plant								
	TRANSMISSION PLANT	10,162,924,834	GNR_TRANS	-	-	10,162,924,834	-	-	10,162,924,834
	Sub-total	10,162,924,834		-	-	10,162,924,834	-	-	10,162,924,834
360-387	Distribution Plant								
	LAND AND LAND RIGHTS	113,493,096	DPLT	-	-	-	-	-	-
	STRUCTURES & IMPROVEMENTS	63,727,935	PRI_DEM	-	-	-	-	-	-
	STATION EQUIPMENT - PRIMARY	1,071,977,540	PRI_DEM	-	-	-	-	-	-
	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQUIP	485,807,532	LABOR_NOTRN	-	-	-	-	-	-
	POLES TOWERS & FIXTURES - PRIMARY	1,378,363,819	PRI_DEM	-	-	-	-	-	-
	POLES TOWERS & FIXTURES - SECONDARY	503,367,775	SEC_DEM	-	-	-	-	-	-
	OVERHEAD CONDUCTORS - PRIMARY	1,393,796,201	PRI_DEM	-	-	-	-	-	-
	OVERHEAD CONDUCTORS - SECONDARY	553,439,348	SEC_DEM	-	-	-	-	-	-
	UNDERGROUND CONDUIT - PRIMARY	361,329,048	PRI_DEM	-	-	-	-	-	-
	UNDERGROUND CONDUIT - SECONDARY	16,564,752	SEC_DEM	-	-	-	-	-	-
	UNDERGROUND CONDUCTORS - PRIMARY	951,215,784	PRI_DEM	-	-	-	-	-	-
	UNDERGROUND CONDUCTORS - SECONDARY	43,607,493	SEC_DEM	-	-	-	-	-	-
	LINE TRANSFORMERS	768,750,265	SEC_DEM	-	-	-	-	-	-
	SERVICES	846,971,069	SEC_CUST	-	-	-	-	-	-
	METERS	341,126,522	DIST	-	-	-	-	-	-
	INSTALLATIONS ON CUST PREMISES	15,029,035	DIST	-	-	-	-	-	-
	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615	DIST	-	-	-	-	-	-
	ENERGY STORAGE EQUIPMENT	621,595	DPLT	-	-	-	-	-	-
	Sub-total	9,139,764,425		-	-	-	-	-	-
389-399	General Plant								
	GENERAL PLANT - DISTRIBUTION	1,061,552,192	LABOR_NOTRN	-	-	-	-	-	-
	GENERAL PLANT - TRANSMISSION	7,755,200	GNR_TRANS	-	-	7,755,200	-	-	7,755,200
Sub-total	1,069,307,392		-	-	7,755,200	-	-	7,755,200	
TOTAL PLANT-IN-SERVICE		20,372,666,945		-	-	10,170,680,034	-	-	10,170,680,034

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
RATE BASE									
Plant-in Service									
301-303	Intangible Plant								
	INTANGIBLE PLANT - DISTRIBUTION	670,295	LABOR_NOTRN	133,113	537,182	-	-	-	670,295
	Sub-total	670,295		133,113	537,182	-	-	-	670,295
350-359	Transmission Plant								
	TRANSMISSION PLANT	10,162,924,834	GNR_TRANS	-	-	-	-	-	-
	Sub-total	10,162,924,834		-	-	-	-	-	-
360-387	Distribution Plant								
	LAND AND LAND RIGHTS	113,493,096	DPLT	56,447,967	57,045,129	-	-	-	113,493,096
	STRUCTURES & IMPROVEMENTS	63,727,935	PRI_DEM	63,727,935	-	-	-	-	63,727,935
	STATION EQUIPMENT - PRIMARY	1,071,977,540	PRI_DEM	1,071,977,540	-	-	-	-	1,071,977,540
	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQUIP	485,807,532	LABOR_NOTRN	96,475,928	389,331,604	-	-	-	485,807,532
	POLES TOWERS & FIXTURES - PRIMARY	1,378,363,819	PRI_DEM	537,975,079	840,388,740	-	-	-	1,378,363,819
	POLES TOWERS & FIXTURES - SECONDARY	503,367,775	SEC_DEM	100,896,363	402,471,412	-	-	-	503,367,775
	OVERHEAD CONDUCTORS - PRIMARY	1,393,796,201	PRI_DEM	764,864,095	628,932,106	-	-	-	1,393,796,201
	OVERHEAD CONDUCTORS - SECONDARY	553,439,348	SEC_DEM	436,593,319	116,846,029	-	-	-	553,439,348
	UNDERGROUND CONDUIT - PRIMARY	361,329,048	PRI_DEM	244,979,109	116,349,939	-	-	-	361,329,048
	UNDERGROUND CONDUIT - SECONDARY	16,564,752	SEC_DEM	11,950,350	4,614,402	-	-	-	16,564,752
	UNDERGROUND CONDUCTORS - PRIMARY	951,215,784	PRI_DEM	644,919,075	306,296,709	-	-	-	951,215,784
	UNDERGROUND CONDUCTORS - SECONDARY	43,607,493	SEC_DEM	31,459,861	12,147,632	-	-	-	43,607,493
	LINE TRANSFORMERS	768,750,265	SEC_DEM	483,261,279	285,488,986	-	-	-	768,750,265
	SERVICES	846,971,069	SEC_CUST	-	846,971,069	-	-	-	846,971,069
	METERS	341,126,522	DIST	-	341,126,522	-	-	-	341,126,522
	INSTALLATIONS ON CUST PREMISES	15,029,035	DIST	-	15,029,035	-	-	-	15,029,035
	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615	DIST	-	230,575,615	-	-	-	230,575,615
	ENERGY STORAGE EQUIPMENT	621,595	DPLT	309,162	312,433	-	-	-	621,595
		Sub-total	9,139,764,425		4,545,837,063	4,593,927,361	-	-	-
389-399	General Plant								
	GENERAL PLANT - DISTRIBUTION	1,061,552,192	LABOR_NOTRN	210,812,361	850,739,831	-	-	-	1,061,552,192
	GENERAL PLANT - TRANSMISSION	7,755,200	GNR_TRANS	-	-	-	-	-	-
	Sub-total	1,069,307,392		210,812,361	850,739,831	-	-	-	1,061,552,192
TOTAL PLANT-IN-SERVICE		20,372,666,945		4,756,782,537	5,445,204,374	-	-	-	10,201,986,912

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	1	2	3	4	5	7
				FERC Transmission					
				Transmission					
				DEM	CUS	GNR	REV	FUL	TOTAL
Accumulated Reserve for Depreciation									
Transmission Plant									
350-359	TRANSMISSION PLANT	1,484,404,073	GNR_TRANS	-	-	1,484,404,073	-	-	1,484,404,073
	Sub-total	1,484,404,073		-	-	1,484,404,073	-	-	1,484,404,073
Distribution Plant									
360	LAND AND LAND RIGHTS	41,596,195	PLT_360	-	-	-	-	-	-
361	STRUCTURES & IMPROVEMENTS	21,397,940	PRI_DEM	-	-	-	-	-	-
362	STATION EQUIPMENT - PRIMARY	234,310,665	PRI_DEM	-	-	-	-	-	-
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQUIP	136,518,580	LABOR_NOTRN	-	-	-	-	-	-
364	POLES TOWERS & FIXTURES - PRIMARY	399,016,926	PRI_DEM	-	-	-	-	-	-
364	POLES TOWERS & FIXTURES - SECONDARY	145,717,886	SEC_DEM	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS - PRIMARY	282,476,603	PRI_DEM	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS - SECONDARY	112,163,935	SEC_DEM	-	-	-	-	-	-
366	UNDERGROUND CONDUIT - PRIMARY	88,182,404	PRI_DEM	-	-	-	-	-	-
366	UNDERGROUND CONDUIT - SECONDARY	4,042,630	SEC_DEM	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS - PRIMARY	285,835,286	PRI_DEM	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS - SECONDARY	13,103,820	SEC_DEM	-	-	-	-	-	-
368	LINE TRANSFORMERS	264,153,503	SEC_DEM	-	-	-	-	-	-
369	SERVICES	430,314,690	SEC_CUST	-	-	-	-	-	-
370	METERS	197,489,696	DIST	-	-	-	-	-	-
371	INSTALLATIONS ON CUST PREMISES	8,531,974	DIST	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	DIST	-	-	-	-	-	-
387	ENERGY STORAGE EQUIPMENT	303,119	DPLT	-	-	-	-	-	-
	Sub-total	2,746,445,884		-	-	-	-	-	-
General Plant									
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	LABOR_NOTRN	-	-	-	-	-	-
389-399	GENERAL PLANT - TRANSMISSION	3,219,909	GNR_TRANS	-	-	3,219,909	-	-	3,219,909
	Sub-total	512,853,412		-	-	3,219,909	-	-	3,219,909
	TOTAL DEPRECIATION ACCRUAL	4,743,703,369		-	-	1,487,623,982	-	-	1,487,623,982
	NET PLANT	15,628,963,576		-	-	8,683,056,052	-	-	8,683,056,052

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
Accumulated Reserve for Depreciation									
350-359	Transmission Plant								
	TRANSMISSION PLANT	1,484,404,073	GNR_TRANS	-	-	-	-	-	-
	Sub-total	1,484,404,073		-	-	-	-	-	-
Distribution Plant									
360	LAND AND LAND RIGHTS	41,596,195	PLT_360	20,688,665	20,907,530	-	-	-	41,596,195
361	STRUCTURES & IMPROVEMENTS	21,397,940	PRI_DEM	21,397,940	-	-	-	-	21,397,940
362	STATION EQUIPMENT - PRIMARY	234,310,665	PRI_DEM	234,310,665	-	-	-	-	234,310,665
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQUIP	136,518,580	LABOR_NOTRN	27,111,059	109,407,521	-	-	-	136,518,580
364	POLES TOWERS & FIXTURES - PRIMARY	399,016,926	PRI_DEM	155,736,214	243,280,712	-	-	-	399,016,926
364	POLES TOWERS & FIXTURES - SECONDARY	145,717,886	SEC_DEM	29,208,077	116,509,809	-	-	-	145,717,886
365	OVERHEAD CONDUCTORS - PRIMARY	282,476,603	PRI_DEM	155,012,771	127,463,832	-	-	-	282,476,603
365	OVERHEAD CONDUCTORS - SECONDARY	112,163,935	SEC_DEM	88,483,092	23,680,843	-	-	-	112,163,935
366	UNDERGROUND CONDUIT - PRIMARY	88,182,404	PRI_DEM	59,787,185	28,395,219	-	-	-	88,182,404
366	UNDERGROUND CONDUIT - SECONDARY	4,042,630	SEC_DEM	2,916,485	1,126,146	-	-	-	4,042,630
367	UNDERGROUND CONDUCTORS - PRIMARY	285,835,286	PRI_DEM	193,794,754	92,040,533	-	-	-	285,835,286
367	UNDERGROUND CONDUCTORS - SECONDARY	13,103,820	SEC_DEM	9,453,521	3,650,299	-	-	-	13,103,820
368	LINE TRANSFORMERS	264,153,503	SEC_DEM	166,055,435	98,098,068	-	-	-	264,153,503
369	SERVICES	430,314,690	SEC_CUST	-	430,314,690	-	-	-	430,314,690
370	METERS	197,489,696	DIST	-	197,489,696	-	-	-	197,489,696
371	INSTALLATIONS ON CUST PREMISES	8,531,974	DIST	-	8,531,974	-	-	-	8,531,974
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	DIST	-	81,290,032	-	-	-	81,290,032
387	ENERGY STORAGE EQUIPMENT	303,119	DPLT	150,762	152,357	-	-	-	303,119
	Sub-total	2,746,445,884		1,164,106,624	1,582,339,260	-	-	-	2,746,445,884
General Plant									
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	LABOR_NOTRN	101,207,499	408,426,004	-	-	-	509,633,503
389-399	GENERAL PLANT - TRANSMISSION	3,219,909	GNR_TRANS	-	-	-	-	-	-
	Sub-total	512,853,412		101,207,499	408,426,004	-	-	-	509,633,503
TOTAL DEPRECIATION ACCRUAL		4,743,703,369		1,265,314,123	1,990,765,264	-	-	-	3,256,079,387
NET PLANT		15,628,963,576		3,491,468,414	3,454,439,110	-	-	-	6,945,907,524

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
Rate Base Adjustments									
Additions									
RB ADJ	CASH WORKING CAPITAL - O&M	6,785,648	OM_CWC	-	-	1,023,373	-	-	1,023,373
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	14,309,000	TAX_CWC	-	-	(5,140,818)	-	-	(5,140,818)
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(33,802,525)	INTRST_CWC	-	-	(18,795,292)	-	-	(18,795,292)
RB ADJ	CASH WORKING CAPITAL - PREPAYMENTS - TRANSMISSION	7,163,535	GNR_TRANS	-	-	7,163,535	-	-	7,163,535
RB ADJ	CASH WORKING CAPITAL - PREPAYMENTS - DISTRIBUTION	6,257,237	TOTDPLT	-	-	-	-	-	-
RB ADJ	MATERIALS AND SUPPLIES - TRANSMISSION	37,144,032	GNR_TRANS	-	-	37,144,032	-	-	37,144,032
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	TOTDPLT	-	-	-	-	-	-
	Sub-total	110,002,454		-	-	21,394,830	-	-	21,394,830
Deductions									
RB ADJ	CIAC - TRANSMISSION	19,034,000	GNR_TRANS	-	-	19,034,000	-	-	19,034,000
RB ADJ	CIAC - DISTRIBUTION	155,133,000	GNR_DIST	-	-	-	-	-	-
RB ADJ	CIAC - GENERAL	213,000	LABOR_NOTRN	-	-	-	-	-	-
RB ADJ	ARCS AND MARCS - TRANSMISSION	(1,421,001,000)	GNR_TRANS	-	-	(1,421,001,000)	-	-	(1,421,001,000)
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	TOTDPLT	-	-	-	-	-	-
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	LABOR_NOTRN	-	-	-	-	-	-
RB ADJ	OTHER 263A REPAIR ALLOWANCES - TRANSMISSION	(12,609,000)	GNR_TRANS	-	-	(12,609,000)	-	-	(12,609,000)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	TOTDPLT	-	-	-	-	-	-
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	LABOR_NOTRN	-	-	-	-	-	-
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	DEPOSIT	-	-	-	-	-	-
	Sub-total	(2,628,302,000)		-	-	(1,414,576,000)	-	-	(1,414,576,000)
TOTAL RATE BASE ADJ.									
		(2,518,299,546)		-	-	(1,393,181,170)	-	-	(1,393,181,170)
TOTAL RATE BASE									
		13,110,664,031		-	-	7,289,874,882	-	-	7,289,874,882

EXPENSES

O & M Expenses

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
Rate Base Adjustments									
Additions									
RB ADJ	CASH WORKING CAPITAL - O&M	6,785,648	OM_CWC	-	-	5,762,275	-	-	5,762,275
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	14,309,000	TAX_CWC	-	-	19,449,818	-	-	19,449,818
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(33,802,525)	INTRST_CWC	-	-	(15,007,233)	-	-	(15,007,233)
RB ADJ	CASH WORKING CAPITAL - PREPAYMENTS - TRANSMISSION	7,163,535	GNR_TRANS	-	-	-	-	-	-
RB ADJ	CASH WORKING CAPITAL - PREPAYMENTS - DISTRIBUTION	6,257,237	TOTDPLT	3,112,157	3,145,080	-	-	-	6,257,237
RB ADJ	MATERIALS AND SUPPLIES - TRANSMISSION	37,144,032	GNR_TRANS	-	-	-	-	-	-
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	TOTDPLT	35,882,961	36,262,566	-	-	-	72,145,527
	Sub-total	110,002,454		38,995,118	39,407,646	10,204,860	-	-	88,607,624
Deductions									
RB ADJ	CIAC - TRANSMISSION	19,034,000	GNR_TRANS	-	-	-	-	-	-
RB ADJ	CIAC - DISTRIBUTION	155,133,000	GNR_DIST	-	-	155,133,000	-	-	155,133,000
RB ADJ	CIAC - GENERAL	213,000	LABOR_NOTRN	42,299	170,701	-	-	-	213,000
RB ADJ	ARCS AND MARCS - TRANSMISSION	(1,421,001,000)	GNR_TRANS	-	-	-	-	-	-
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	TOTDPLT	(387,334,698)	(391,432,302)	-	-	-	(778,767,000)
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	LABOR_NOTRN	(19,123,306)	(77,172,694)	-	-	-	(96,296,000)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - TRANSMISSION	(12,609,000)	GNR_TRANS	-	-	-	-	-	-
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	TOTDPLT	(248,827,828)	(251,460,172)	-	-	-	(500,288,000)
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	LABOR_NOTRN	2,548,490	10,284,510	-	-	-	12,833,000
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	DEPOSIT	-	(6,554,000)	-	-	-	(6,554,000)
	Sub-total	(2,628,302,000)	-	(652,695,043)	(716,163,957)	155,133,000	-	-	(1,213,726,000)
TOTAL RATE BASE ADJ.									
		(2,518,299,546)		(613,699,925)	(676,756,311)	165,337,860	-	-	(1,125,118,376)
TOTAL RATE BASE									
		13,110,664,031		2,877,768,490	2,777,682,799	165,337,860	-	-	5,820,789,148

EXPENSES

O & M Expenses

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	1	2	3	4	5	7
				FERC Transmission					
				Transmission					
				DEM	CUS	GNR	REV	FUL	TOTAL
Transmission Operation Expenses									
560-567	TRANSMISSION OPERATION EXPENSES	17,254,548	GNR_TRANS	-	-	17,254,548	-	-	17,254,548
	Sub-total	17,254,548		-	-	17,254,548	-	-	17,254,548
Transmission Maintenance Expenses									
568-576	TRANSMISSION MAINTENANCE EXPENSES	17,914,082	GNR_TRANS	-	-	17,914,082	-	-	17,914,082
	Sub-total	17,914,082		-	-	17,914,082	-	-	17,914,082
	Total Transmission	35,168,630		-	-	35,168,630	-	-	35,168,630
Distribution Operation Expenses									
580	SUPERVISION AND ENGINEERING	10,367,332	DISTOPLBR	-	-	-	-	-	-
581	LOAD DISPATCHING	2,294,615	PLT_360_2	-	-	-	-	-	-
582	STATION EXPENSES	86,108	PLT_360_2	-	-	-	-	-	-
583	OVERHEAD LINES	29,067,041	PLT_364_5	-	-	-	-	-	-
584	UNDERGROUND LINES	6,594,454	PLT_366_7	-	-	-	-	-	-
586	METER EXPENSE	2,391,010	PLT_370	-	-	-	-	-	-
587	CUSTOMER INSTALLATION EXPENSE	3,025,958	DIST	-	-	-	-	-	-
588	MISC. DISTRIBUTION EXPENSE	18,180,878	DPLT	-	-	-	-	-	-
589	RENTS	7,534,350	DPLT	-	-	-	-	-	-
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000	LABOR_NOTRN	-	-	-	-	-	-
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(518,000)	LABOR	-	(4,120)	(39,261)	-	-	(43,381)
PROFORMA	RATE CASE EXPENSES	733,000	GNR_DIST	-	-	-	-	-	-
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000	DEPOSIT	-	-	-	-	-	-
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000	GNR_DIST	-	-	-	-	-	-
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE RATES	-	DIST	-	-	-	-	-	-
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000	GNR_DIST	-	-	-	-	-	-
PROFORMA	IIJA-RELATED INCREMENTAL EXPENDITURES	211,000	GNR_DIST	-	-	-	-	-	-
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)	DIST	-	-	-	-	-	-
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)	LABOR_NOTRN	-	-	-	-	-	-
	Sub-total	82,579,747		-	(4,120)	(39,261)	-	-	(43,381)
Distribution Maintenance Expenses									
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-
591	STRUCTURES	137,306	PLT_360_2	-	-	-	-	-	-
592	STATION EQUIPMENT	12,304,925	PLT_360_2	-	-	-	-	-	-
593	OVERHEAD LINES	85,378,325	PLT_364_5	-	-	-	-	-	-
593.5	OVERHEAD LINES - SERVICES	25,336,746	SEC_DEM	-	-	-	-	-	-
594	UNDERGROUND LINES	340,244	PLT_366_7	-	-	-	-	-	-
595	LINE TRANSFORMERS	182,284	SEC_DEM	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105	DIST	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606	DPLT	-	-	-	-	-	-
	Sub-total	128,170,541		-	-	-	-	-	-
	Total Distribution	210,750,288		-	(4,120)	(39,261)	-	-	(43,381)

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
560-567	Transmission Operation Expenses								
	TRANSMISSION OPERATION EXPENSES	17,254,548	GNR_TRANS	-	-	-	-	-	-
	Sub-total	17,254,548		-	-	-	-	-	-
568-576	Transmission Maintenance Expenses								
	TRANSMISSION MAINTENANCE EXPENSES	17,914,082	GNR_TRANS	-	-	-	-	-	-
	Sub-total	17,914,082		-	-	-	-	-	-
	Total Transmission	35,168,630		-	-	-	-	-	-
	Distribution Operation Expenses								
580	SUPERVISION AND ENGINEERING	10,367,332	DISTOPLBR	4,360,135	6,007,197	-	-	-	10,367,332
581	LOAD DISPATCHING	2,294,615	PLT_360_2	2,189,831	104,784	-	-	-	2,294,615
582	STATION EXPENSES	86,108	PLT_360_2	82,176	3,932	-	-	-	86,108
583	OVERHEAD LINES	29,067,041	PLT_364_5	13,970,586	15,096,455	-	-	-	29,067,041
584	UNDERGROUND LINES	6,594,454	PLT_366_7	4,483,560	2,110,894	-	-	-	6,594,454
586	METER EXPENSE	2,391,010	PLT_370	-	2,391,010	-	-	-	2,391,010
587	CUSTOMER INSTALLATION EXPENSE	3,025,958	DIST	-	3,025,958	-	-	-	3,025,958
588	MISC. DISTRIBUTION EXPENSE	18,180,878	DPLT	9,042,608	9,138,270	-	-	-	18,180,878
589	RENTS	7,534,350	DPLT	3,747,353	3,786,997	-	-	-	7,534,350
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000	LABOR_NOTRN	269,882	1,089,118	-	-	-	1,359,000
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(518,000)	LABOR	(94,254)	(380,365)	-	-	-	(474,619)
PROFORMA	RATE CASE EXPENSES	733,000	GNR_DIST	-	-	733,000	-	-	733,000
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000	DEPOSIT	-	300,000	-	-	-	300,000
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000	GNR_DIST	-	-	400,000	-	-	400,000
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE RATES	-	DIST	-	-	-	-	-	-
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000	GNR_DIST	-	-	3,779,000	-	-	3,779,000
PROFORMA	IIJA-RELATED INCREMENTAL EXPENDITURES	211,000	GNR_DIST	-	-	211,000	-	-	211,000
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)	DIST	-	(1,400,000)	-	-	-	(1,400,000)
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)	LABOR_NOTRN	(362,623)	(1,463,377)	-	-	-	(1,826,000)
	Sub-total	82,579,747		37,689,254	39,810,875	5,123,000	-	-	82,623,129
	Distribution Maintenance Expenses								
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-
591	STRUCTURES	137,306	PLT_360_2	131,036	6,270	-	-	-	137,306
592	STATION EQUIPMENT	12,304,925	PLT_360_2	11,743,015	561,909	-	-	-	12,304,925
593	OVERHEAD LINES	85,378,325	PLT_364_5	41,035,660	44,342,665	-	-	-	85,378,325
593.5	OVERHEAD LINES - SERVICES	25,336,746	SEC_DEM	-	25,336,746	-	-	-	25,336,746
594	UNDERGROUND LINES	340,244	PLT_366_7	231,331	108,913	-	-	-	340,244
595	LINE TRANSFORMERS	182,284	SEC_DEM	114,589	67,694	-	-	-	182,284
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105	DIST	-	2,424,105	-	-	-	2,424,105
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606	DPLT	1,027,866	1,038,740	-	-	-	2,066,606
	Sub-total	128,170,541		54,283,499	73,887,042	-	-	-	128,170,541
	Total Distribution	210,750,288		91,972,752	113,697,917	5,123,000	-	-	210,793,669

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	1	2	3	4	5	7
				FERC Transmission					
				Transmission					
				DEM	CUS	GNR	REV	FUL	TOTAL
Customer Account									
901	SUPERVISION	4,016,323	CUSTACCTLBR	-	-	-	-	-	-
902	METER READING	1,205,576	CUST	-	-	-	-	-	-
903CR	CUSTOMER RECORDS	25,189,595	CUST	-	-	-	-	-	-
903CE	COLLECTION EXPENSES	14,177,408	DIST	-	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000	DPLT	-	-	-	-	-	-
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983	DIST	-	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596	CUST	-	-	-	-	-	-
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504	DIST	-	-	-	-	-	-
904-MFC	MFC ADJUSTMENT	(18,111,000)	DIST	-	-	-	-	-	-
	Sub-total	73,553,985		-	-	-	-	-	-
Customer Service & Information Expenses									
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873	DIST	-	-	-	-	-	-
	Sub-total	22,026,873		-	-	-	-	-	-
Sales Expenses									
911-916	SALES EXPENSES	-	DIST	-	-	-	-	-	-
	Sub-total	-		-	-	-	-	-	-
Administrative and General Expenses									
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572	LABOR_NOTRN	-	-	-	-	-	-
924	PROPERTY INSURANCE - DIST	2,058,405	DPLT	-	-	-	-	-	-
925	INJURIES & DAMAGES - DIST	6,965,752	LABOR_NOTRN	-	-	-	-	-	-
926	EMPLOYEE BENEFITS - DIST	2,395,082	LABOR_NOTRN	-	-	-	-	-	-
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737	DIST	-	-	-	-	-	-
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)	DPLT	-	-	-	-	-	-
931	RENT/FACILITIES - DIST	916,027	DPLT	-	-	-	-	-	-
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748	LABOR_NOTRN	-	-	-	-	-	-
920-923	A&G SALARIES & OFFICE SUPPLIES - TRAN	26,118,535	TRANS	-	26,118,535	-	-	-	26,118,535
924	PROPERTY INSURANCE - TRAN	1,896,754	TRANS	-	1,896,754	-	-	-	1,896,754
925	INJURIES & DAMAGES - TRAN	1,582,030	TRANS	-	1,582,030	-	-	-	1,582,030
926	EMPLOYEE BENEFITS - TRAN	610,404	TRANS	-	610,404	-	-	-	610,404
930	GENERAL ADVERTISING EXPENSE - TRAN	1,152,787	TRANS	-	1,152,787	-	-	-	1,152,787
931	RENT/FACILITIES - TRANS	249,285	TRANS	-	249,285	-	-	-	249,285
935	MAINTENANCE OF GENERAL PLANT - TRAN	6,506,316	TRANS	-	6,506,316	-	-	-	6,506,316
928	PUC FEE INCREASE	1,110,654	DIST	-	-	-	-	-	-
	Sub-total	170,073,229		-	38,116,112	-	-	-	38,116,112
TOTAL O & M EXPENSES		511,573,005		-	38,111,992	35,129,369	-	-	73,241,361

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

Jurisdictional Cost of Service Study				8	9	10	11	12	13	15
Detailed Cost Allocation Results				PUC Jurisdiction Distribution						
Fully Projected Future Test Year				Distribution						
No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL	
Customer Account										
901	SUPERVISION	4,016,323	CUSTACCTLBR	-	4,016,323	-	-	-	4,016,323	
902	METER READING	1,205,576	CUST	-	1,205,576	-	-	-	1,205,576	
903CR	CUSTOMER RECORDS	25,189,595	CUST	-	25,189,595	-	-	-	25,189,595	
903CE	COLLECTION EXPENSES	14,177,408	DIST	-	14,177,408	-	-	-	14,177,408	
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000	DPLT	2,098,898	2,121,102	-	-	-	4,220,000	
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983	DIST	-	32,845,983	-	-	-	32,845,983	
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596	CUST	-	3,588,596	-	-	-	3,588,596	
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504	DIST	-	6,421,504	-	-	-	6,421,504	
904-MFC	MFC ADJUSTMENT	(18,111,000)	DIST	-	(18,111,000)	-	-	-	(18,111,000)	
	Sub-total	73,553,985		2,098,898	71,455,087	-	-	-	73,553,985	
Customer Service & Information Expenses										
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873	DIST	-	22,026,873	-	-	-	22,026,873	
	Sub-total	22,026,873		-	22,026,873	-	-	-	22,026,873	
Sales Expenses										
911-916	SALES EXPENSES	-	DIST	-	-	-	-	-	-	
	Sub-total	-		-	-	-	-	-	-	
Administrative and General Expenses										
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572	LABOR_NOTRN	17,139,319	69,166,253	-	-	-	86,305,572	
924	PROPERTY INSURANCE - DIST	2,058,405	DPLT	1,023,787	1,034,618	-	-	-	2,058,405	
925	INJURIES & DAMAGES - DIST	6,965,752	LABOR_NOTRN	1,383,320	5,582,431	-	-	-	6,965,752	
926	EMPLOYEE BENEFITS - DIST	2,395,082	LABOR_NOTRN	475,636	1,919,446	-	-	-	2,395,082	
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737	DIST	-	6,663,737	-	-	-	6,663,737	
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)	DPLT	(6,409,029)	(6,476,830)	-	-	-	(12,885,859)	
931	RENT/FACILITIES - DIST	916,027	DPLT	455,604	460,424	-	-	-	916,027	
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748	LABOR_NOTRN	7,631,320	30,796,428	-	-	-	38,427,748	
920-923	A&G SALARIES & OFFICE SUPPLIES - TRAN	26,118,535	TRANS	-	-	-	-	-	-	
924	PROPERTY INSURANCE - TRAN	1,896,754	TRANS	-	-	-	-	-	-	
925	INJURIES & DAMAGES - TRAN	1,582,030	TRANS	-	-	-	-	-	-	
926	EMPLOYEE BENEFITS - TRAN	610,404	TRANS	-	-	-	-	-	-	
930	GENERAL ADVERTISING EXPENSE - TRAN	1,152,787	TRANS	-	-	-	-	-	-	
931	RENT/FACILITIES - TRANS	249,285	TRANS	-	-	-	-	-	-	
935	MAINTENANCE OF GENERAL PLANT - TRAN	6,506,316	TRANS	-	-	-	-	-	-	
928	PUC FEE INCREASE	1,110,654	DIST	-	1,110,654	-	-	-	1,110,654	
	Sub-total	170,073,229		21,699,957	110,257,160	-	-	-	131,957,117	
TOTAL O & M EXPENSES		511,573,005		115,771,607	317,437,037	5,123,000	-	-	438,331,644	

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
Labor Expense									
560-567	Transmission Operation Expenses								
	TRANSMISSION OPERATION EXPENSES	2,746,006	GNR_TRANS	-	-	2,746,006	-	-	2,746,006
	Sub-total	2,746,006		-	-	2,746,006	-	-	2,746,006
568-576	Transmission Maintenance Expenses								
	TRANSMISSION MAINTENANCE EXPENSES	3,452,973	GNR_TRANS	-	-	3,452,973	-	-	3,452,973
	Sub-total	3,452,973		-	-	3,452,973	-	-	3,452,973
	Total Transmission	6,198,979		-	-	6,198,979	-	-	6,198,979
Distribution Operation Expenses									
580	SUPERVISION AND ENGINEERING	2,531,568	DISTOPLBR	-	-	-	-	-	-
581	LOAD DISPATCHING	205,354	PLT_360_2	-	-	-	-	-	-
582	STATION EXPENSES	63,106	PLT_360_2	-	-	-	-	-	-
583	OVERHEAD LINES	11,129,059	PLT_364_5	-	-	-	-	-	-
584	UNDERGROUND LINES	1,412,410	PLT_366_7	-	-	-	-	-	-
585	STREET LIGHTING & SIGNAL SYSTEMS	-	DIST	-	-	-	-	-	-
586	METER EXPENSE	1,774,160	PLT_370	-	-	-	-	-	-
587	CUSTOMER INSTALLATION EXPENSE	1,484,627	DIST	-	-	-	-	-	-
588	MISC. DISTRIBUTION EXPENSE	2,505,643	DPLT	-	-	-	-	-	-
589	RENTS	-	DPLT	-	-	-	-	-	-
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-
	Sub-total	21,105,928		-	-	-	-	-	-
Distribution Maintenance Expenses									
590	SUPERVISION AND ENGINEERING	-	DMAINTLBR	-	-	-	-	-	-
591	STRUCTURES	-	PLT_360_2	-	-	-	-	-	-
592	STATION EQUIPMENT	1,261,242	PLT_360_2	-	-	-	-	-	-
593	OVERHEAD LINES	9,796,738	PLT_364_5	-	-	-	-	-	-
594	UNDERGROUND LINES	55,053	PLT_366_7	-	-	-	-	-	-
596	STREET LIGHT & SIGNAL SYSTEMS	739,646	DIST	-	-	-	-	-	-
598	MISCELLANEOUS DISTRIB. PLANT	112,216	DPLT	-	-	-	-	-	-
	Sub-total	11,964,895		-	-	-	-	-	-
	Total Distribution	33,070,822		-	-	-	-	-	-

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

No.	Account Description	Amount	Alloc. Factor	8	9	10	11	12	13	15
				PUC Jurisdiction Distribution						
				Distribution						
				DEM	CUS	GNR	REV	FUL		TOTAL
Labor Expense										
	Transmission Operation Expenses									
560-567	TRANSMISSION OPERATION EXPENSES	2,746,006	GNR_TRANS	-	-	-	-	-	-	-
	Sub-total	2,746,006		-	-	-	-	-	-	-
	Transmission Maintenance Expenses									
568-576	TRANSMISSION MAINTENANCE EXPENSES	3,452,973	GNR_TRANS	-	-	-	-	-	-	-
	Sub-total	3,452,973		-	-	-	-	-	-	-
	Total Transmission	6,198,979		-	-	-	-	-	-	-
	Distribution Operation Expenses									
580	SUPERVISION AND ENGINEERING	2,531,568	DISTOPLBR	1,064,689	1,466,880	-	-	-	-	2,531,568
581	LOAD DISPATCHING	205,354	PLT_360_2	195,976	9,378	-	-	-	-	205,354
582	STATION EXPENSES	63,106	PLT_360_2	60,224	2,882	-	-	-	-	63,106
583	OVERHEAD LINES	11,129,059	PLT_364_5	5,348,996	5,780,063	-	-	-	-	11,129,059
584	UNDERGROUND LINES	1,412,410	PLT_366_7	960,296	452,114	-	-	-	-	1,412,410
585	STREET LIGHTING & SIGNAL SYSTEMS	-	DIST	-	-	-	-	-	-	-
586	METER EXPENSE	1,774,160	PLT_370	-	1,774,160	-	-	-	-	1,774,160
587	CUSTOMER INSTALLATION EXPENSE	1,484,627	DIST	-	1,484,627	-	-	-	-	1,484,627
588	MISC. DISTRIBUTION EXPENSE	2,505,643	DPLT	1,246,229	1,259,413	-	-	-	-	2,505,643
589	RENTS	-	DPLT	-	-	-	-	-	-	-
577-578	ENERGY STORAGE O&M	-	DPLT	-	-	-	-	-	-	-
	Sub-total	21,105,928		8,876,410	12,229,518	-	-	-	-	21,105,928
	Distribution Maintenance Expenses									
590	SUPERVISION AND ENGINEERING	-	DMaintLBR	-	-	-	-	-	-	-
591	STRUCTURES	-	PLT_360_2	-	-	-	-	-	-	-
592	STATION EQUIPMENT	1,261,242	PLT_360_2	1,203,647	57,595	-	-	-	-	1,261,242
593	OVERHEAD LINES	9,796,738	PLT_364_5	4,708,638	5,088,100	-	-	-	-	9,796,738
594	UNDERGROUND LINES	55,053	PLT_366_7	37,430	17,623	-	-	-	-	55,053
596	STREET LIGHT & SIGNAL SYSTEMS	739,646	DIST	-	739,646	-	-	-	-	739,646
598	MISCELLANEOUS DISTRIB. PLANT	112,216	DPLT	55,813	56,403	-	-	-	-	112,216
	Sub-total	11,964,895		6,005,528	5,959,367	-	-	-	-	11,964,895
	Total Distribution	33,070,822		14,881,938	18,188,884	-	-	-	-	33,070,822

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	1	2	3	4	5	7
				FERC Transmission					
				Transmission					
				DEM	CUS	GNR	REV	FUL	TOTAL
Customer Account									
901	SUPERVISION	3,084,792	CUSTACCTLBR	-	-	-	-	-	-
902	METER READING	-	CUST	-	-	-	-	-	-
903CR	CUSTOMER RECORDS	15,198,749	CUST	-	-	-	-	-	-
903CE	COLLECTION EXPENSES	-	DIST	-	-	-	-	-	-
904 T	UNCOLLECTIBLE ACCOUNTS TRANSMISSION	-	TRANS	-	-	-	-	-	-
904 D	PROPERTY DAMAGE DISTRIBUTION	-	DPLT	-	-	-	-	-	-
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-	DIST	-	-	-	-	-	-
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080	CUST	-	-	-	-	-	-
	Sub-total	18,430,621		-	-	-	-	-	-
Customer Service & Information Expenses									
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	DIST	-	-	-	-	-	-
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759	DIST	-	-	-	-	-	-
	Sub-total	10,495,759		-	-	-	-	-	-
Sales Expenses									
911-916	SALES EXPENSES	-	DIST	-	-	-	-	-	-
920-935	A&G - TRANSMISSION	650,588	TRANS	-	650,588	-	-	-	650,588
920-935	A&G - DISTIRBUTION	12,941,259	DIST	-	-	-	-	-	-
	Sub-total	13,591,846		-	650,588	-	-	-	650,588
	TOTAL O & M LABOR EXP.	81,788,028		-	650,588	6,198,979	-	-	6,849,567

Depreciation Expense

Transmission Plant									
350-359	TRANSMISSION PLANT	224,744,340	GNR_TRANS	-	-	224,744,340	-	-	224,744,340
	Sub-total	224,744,340		-	-	224,744,340	-	-	224,744,340
Distribution Plant									
360	LAND AND LAND RIGHTS	756,214	PLT_360	-	-	-	-	-	-
361	STRUCTURES & IMPROVEMENTS	814,601	PLT_360_1	-	-	-	-	-	-
362	STATION EQUIPMENT	20,033,725	PLT_362	-	-	-	-	-	-
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQUIP	66,278,524	LABOR_NOTRN	-	-	-	-	-	-
364	POLES TOWERS & FIXTURES	42,177,610	PLT_364	-	-	-	-	-	-
365	OVERHEAD CONDUCTORS	45,318,655	PLT_365	-	-	-	-	-	-
366	UNDERGROUND CONDUIT	5,484,850	PLT_366	-	-	-	-	-	-
367	UNDERGROUND CONDUCTORS	17,061,472	PLT_367	-	-	-	-	-	-
368	LINE TRANSFORMERS	23,171,156	SEC_DEM	-	-	-	-	-	-
369	SERVICES	9,866,936	SEC_CUST	-	-	-	-	-	-
370	METERS	26,031,923	PLT_370	-	-	-	-	-	-
371	INSTALLATIONS ON CUST PREMISES	476,054	DIST	-	-	-	-	-	-
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971	DIST	-	-	-	-	-	-
387	ENERGY STORAGE EQUIPMENT	42,520	DPLT	-	-	-	-	-	-
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000	GNR_DIST	-	-	-	-	-	-
	Sub-total	264,935,209		-	-	-	-	-	-

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

Jurisdictional Cost of Service Study				8	9	10	11	12	13	15
Detailed Cost Allocation Results				PUC Jurisdiction Distribution						
Fully Projected Future Test Year				Distribution						
No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL	
Customer Account										
901	SUPERVISION	3,084,792	CUSTACCTLBR	-	3,084,792	-	-	-	3,084,792	
902	METER READING	-	CUST	-	-	-	-	-	-	
903CR	CUSTOMER RECORDS	15,198,749	CUST	-	15,198,749	-	-	-	15,198,749	
903CE	COLLECTION EXPENSES	-	DIST	-	-	-	-	-	-	
904 T	UNCOLLECTIBLE ACCOUNTS TRANSMISSION	-	TRANS	-	-	-	-	-	-	
904 D	PROPERTY DAMAGE DISTRIBUTION	-	DPLT	-	-	-	-	-	-	
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-	DIST	-	-	-	-	-	-	
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080	CUST	-	147,080	-	-	-	147,080	
	Sub-total	18,430,621		-	18,430,621	-	-	-	18,430,621	
Customer Service & Information Expenses										
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-	DIST	-	-	-	-	-	-	
908 Other - 910	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759	DIST	-	10,495,759	-	-	-	10,495,759	
	Sub-total	10,495,759		-	10,495,759	-	-	-	10,495,759	
Sales Expenses										
911-916	SALES EXPENSES	-	DIST	-	-	-	-	-	-	
920-935	A&G - TRANSMISSION	650,588	TRANS	-	-	-	-	-	-	
920-935	A&G - DISTIRBUTION	12,941,259	DIST	-	12,941,259	-	-	-	12,941,259	
	Sub-total	13,591,846		-	12,941,259	-	-	-	12,941,259	
TOTAL O & M LABOR EXP.		81,788,028		14,881,938	60,056,523	-	-	-	74,938,461	

Depreciation Expense

Transmission Plant									
350-359	TRANSMISSION PLANT	224,744,340	GNR_TRANS	-	-	-	-	-	-
	Sub-total	224,744,340		-	-	-	-	-	-
Distribution Plant									
360	LAND AND LAND RIGHTS	756,214	PLT_360	376,118	380,096	-	-	-	756,214
361	STRUCTURES & IMPROVEMENTS	814,601	PLT_360_1	552,392	262,209	-	-	-	814,601
362	STATION EQUIPMENT	20,033,725	PLT_362	20,033,725	-	-	-	-	20,033,725
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNICATION EQUIP	66,278,524	LABOR_NOTRN	13,162,172	53,116,352	-	-	-	66,278,524
364	POLES TOWERS & FIXTURES	42,177,610	PLT_364	14,319,827	27,857,783	-	-	-	42,177,610
365	OVERHEAD CONDUCTORS	45,318,655	PLT_365	27,961,915	17,356,740	-	-	-	45,318,655
366	UNDERGROUND CONDUIT	5,484,850	PLT_366	3,729,142	1,755,708	-	-	-	5,484,850
367	UNDERGROUND CONDUCTORS	17,061,472	PLT_367	11,600,070	5,461,401	-	-	-	17,061,472
368	LINE TRANSFORMERS	23,171,156	SEC_DEM	14,566,138	8,605,018	-	-	-	23,171,156
369	SERVICES	9,866,936	SEC_CUST	-	9,866,936	-	-	-	9,866,936
370	METERS	26,031,923	PLT_370	-	26,031,923	-	-	-	26,031,923
371	INSTALLATIONS ON CUST PREMISES	476,054	DIST	-	476,054	-	-	-	476,054
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971	DIST	-	5,594,971	-	-	-	5,594,971
387	ENERGY STORAGE EQUIPMENT	42,520	DPLT	21,148	21,372	-	-	-	42,520
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000	GNR_DIST	-	-	1,826,000	-	-	1,826,000
	Sub-total	264,935,209		106,322,645	156,786,563	1,826,000	-	-	264,935,209

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

No.	Account Description	Amount	Alloc. Factor	1	2	3	4	5	7
				FERC Transmission					
				Transmission					
				DEM	CUS	GNR	REV	FUL	TOTAL
	General Plant								
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699	LABOR_NOTRN	-	-	-	-	-	-
389-399	GENERAL PLANT - TRANSMISSION	500,938	GNR_TRANS	-	-	500,938	-	-	500,938
	Sub-total	59,721,637		-	-	500,938	-	-	500,938
	TOTAL DEPRECIATION EXPENSES	549,401,186		-	-	225,245,278	-	-	225,245,278

Taxes Other Than Income Taxes

TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)	GNR_DIST	-	-	-	-	-	-
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)	GNR_DIST	-	-	-	-	-	-
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000	DPLT	-	-	-	-	-	-
TAX	DEFERRED TAXES - LABOR	23,224,000	LABOR_NOTRN	-	-	-	-	-	-
TAX	DEFERRED TAXES - TRANSMISSION	90,066,000	GNR_TRANS	-	-	90,066,000	-	-	90,066,000
TAX	PROPERTY TAX - TRANSMISSION	1,818,000	GNR_TRANS	-	-	1,818,000	-	-	1,818,000
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000	GNR_DIST	-	-	-	-	-	-
TAX	PUBLIC UTILITY REALTY - TRANSMISSION	1,610,000	GNR_TRANS	-	-	1,610,000	-	-	1,610,000
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000	GNR_DIST	-	-	-	-	-	-
TAX	INVESTMENT TAX CREDIT - TRANSMISSION	(16,000)	GNR_TRANS	-	-	(16,000)	-	-	(16,000)
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)	GNR_DIST	-	-	-	-	-	-
TAX	OTHER TAXES - LABOR	4,862,000	LABOR_NOTRN	-	-	-	-	-	-
TAX	OTHER TAXES - TRANSMISSION	659,000	GNR_TRANS	-	-	659,000	-	-	659,000
TAX	GROSS RECEIPTS TAX	56,151,000	GNR_DIST	-	-	-	-	-	-
TAX	GROSS RECEIPTS TAX + COMMISSION FEES - INCREASE	22,406,453	GNR_DIST	-	-	-	-	-	-
	Sub-total	227,971,453		-	-	94,137,000	-	-	94,137,000
	TOTAL TAXES OTHER THAN INCOME TAX	227,971,453		-	-	94,137,000	-	-	94,137,000

Adjustments to Taxable Income

TAX	TAX ADJUSTMENT - TRANS RELATED	(317,092,000)	GNR_TRANS	-	-	(317,092,000)	-	-	(317,092,000)
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)	GNR_DIST	-	-	-	-	-	-
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000	GNR_DIST	-	-	-	-	-	-
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000	DEPR_DPLT	-	-	-	-	-	-
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)	DEPR_GIPLT	-	-	-	-	-	-
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000	DPLT	-	-	-	-	-	-
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000	LABOR_NOTRN	-	-	-	-	-	-
	Sub-total	(551,426,000)		-	-	(317,092,000)	-	-	(317,092,000)

**Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year**

		8	9	10	11	12	13	15
		PUC Jurisdiction Distribution						
No.	Account Description	Amount	Alloc. Factor	Distribution				
				DEM	CUS	GNR	REV	FUL
	General Plant							
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699	LABOR_NOTRN	11,760,567	47,460,133	-	-	-
389-399	GENERAL PLANT - TRANSMISSION	500,938	GNR_TRANS	-	-	-	-	-
	Sub-total	59,721,637		11,760,567	47,460,133	-	-	-
	TOTAL DEPRECIATION EXPENSES	549,401,186		118,083,212	204,246,696	1,826,000	-	-
	Taxes Other Than Income Taxes							
TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)	GNR_DIST	-	-	(2,515,000)	-	-
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)	GNR_DIST	-	-	(102,000)	-	-
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000	DPLT	12,863,459	12,999,541	-	-	-
TAX	DEFERRED TAXES - LABOR	23,224,000	LABOR_NOTRN	4,612,026	18,611,974	-	-	-
TAX	DEFERRED TAXES - TRANSMISSION	90,066,000	GNR_TRANS	-	-	-	-	-
TAX	PROPERTY TAX - TRANSMISSION	1,818,000	GNR_TRANS	-	-	-	-	-
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000	GNR_DIST	-	-	2,460,000	-	-
TAX	PUBLIC UTILITY REALTY - TRANSMISSION	1,610,000	GNR_TRANS	-	-	-	-	-
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000	GNR_DIST	-	-	1,500,000	-	-
TAX	INVESTMENT TAX CREDIT - TRANSMISSION	(16,000)	GNR_TRANS	-	-	-	-	-
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)	GNR_DIST	-	-	(15,000)	-	-
TAX	OTHER TAXES - LABOR	4,862,000	LABOR_NOTRN	965,539	3,896,461	-	-	-
TAX	OTHER TAXES - TRANSMISSION	659,000	GNR_TRANS	-	-	-	-	-
TAX	GROSS RECEIPTS TAX	56,151,000	GNR_DIST	-	-	56,151,000	-	-
TAX	GROSS RECEIPTS TAX + COMMISSION FEES - INCREASE	22,406,453	GNR_DIST	-	-	22,406,453	-	-
	Sub-total	227,971,453		18,441,024	35,507,976	79,885,453	-	-
	TOTAL TAXES OTHER THAN INCOME TAX	227,971,453		18,441,024	35,507,976	79,885,453	-	-
	Adjustments to Taxable Income							
TAX	TAX ADJUSTMENT - TRANS RELATED	(317,092,000)	GNR_TRANS	-	-	-	-	-
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)	GNR_DIST	-	-	(203,479,000)	-	-
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000	GNR_DIST	-	-	5,160,000	-	-
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000	DEPR_DPLT	17,350,481	25,585,540	297,980	-	-
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)	DEPR_GIPLT	(18,841,508)	(76,035,492)	-	-	-
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000	DPLT	187,011	188,989	-	-	-
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000	LABOR_NOTRN	3,028,876	12,223,124	-	-	-
	Sub-total	(551,426,000)		1,724,859	(38,037,839)	(198,021,020)	-	-

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

Jurisdictional Cost of Service Study				1	2	3	4	5	7
Detailed Cost Allocation Results				FERC Transmission					
Fully Projected Future Test Year				Transmission					
No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL
PA Special Deductions									
TAX	PA SPECIAL DEDUCTIONS - TRANSMISSION RELATED	(90,437,000)	GNR_TRANS	-	-	(90,437,000)	-	-	(90,437,000)
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELATED	(33,338,000)	DEPR_DPLT	-	-	-	-	-	-
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)	DPLT	-	-	-	-	-	-
TAX	FEDEARL TAX CREDIT - TRANS	(500,000)	GNR_TRANS	-	-	(500,000)	-	-	(500,000)
TAX	FEDEARL TAX CREDIT - DIST	(900,000)	DPLT	-	-	-	-	-	-
	TOTAL	(126,075,000)		-	-	(90,937,000)	-	-	(90,937,000)
Net Addition:		-		0	-	(408,029,000)	-	-	(408,029,000)
Fuel and Purchased Power									
555	PURCHASED POWER	-	FUEL	-	-	-	-	-	-
557	OTHER PURCHASED POWER EXPENSES	323,299	FUEL	-	-	-	-	-	-
	TOTAL	323,299		0	-	-	-	-	-
Income Taxes									
TAX	INCOME TAXES - STATE - PRESENT	(2,990,874)	INCTAX	-	-	(10,448,575)	-	-	(10,448,575)
TAX	INCOME TAXES - FEDERAL - PRESENT	16,330,026	INCTAX	-	-	57,048,711	-	-	57,048,711
TAX	INCOME TAXES - STATE - INCREASE	25,794,792	GNR_DIST	-	-	-	-	-	-
TAX	INCOME TAXES - FEDERAL - INCREASE	69,402,242	GNR_DIST	-	-	-	-	-	-
	TOTAL	108,536,187		0	-	46,600,135	-	-	46,600,135
Operating Revenues									
REV	TRANSMISSION REVENUES	-	REV_TRANS	-	-	-	-	-	-
REV	DISTRIBUTION REVENUES	1,004,890,414	REV_DIST	-	-	-	-	-	-
REV	STATE TAX ADJ SURCHARGE	-	REV_DIST	-	-	-	-	-	-
REV	LATE PAYMENT CHARGES	15,305,520	REV_DIST	-	-	-	-	-	-
REV	ANNUALIZATION	4,932,874	REV_DIST	-	-	-	-	-	-
REV	MISCELLANEOUS SERVICE REVS	969,910	REV_DIST	-	-	-	-	-	-
REV	RENT-ELECTRIC PROPERTY - TRAN	2,916,000	REV_TRANS	-	-	-	2,916,000	-	2,916,000
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268	REV_DIST	-	-	-	-	-	-
REV	OTHER ELECTRIC REVENUE - TRAN	974,520,326	REV_TRANS	-	-	-	974,520,326	-	974,520,326
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960	REV_DIST	-	-	-	-	-	-
REV	RESALE REVENUES	318,877	REV_DIST	-	-	-	-	-	-
REV	BL REVENUES	348,811	REV_DIST	-	-	-	-	-	-
REV	LATE PAYMENT CHARGES INCREASE	1,699,050	REV_DIST	-	-	-	-	-	-
	Sub-total	2,049,756,011		-	-	-	977,436,326	-	977,436,326
	TOTAL	2,049,756,011		-	-	-	977,436,326	-	977,436,326

Jurisdictional Cost of Service Study
Detailed Cost Allocation Results
Fully Projected Future Test Year

Jurisdictional Cost of Service Study				8	9	10	11	12	13	15		
Detailed Cost Allocation Results				PUC Jurisdiction Distribution								
Fully Projected Future Test Year				Distribution								
No.	Account Description	Amount	Alloc. Factor	DEM	CUS	GNR	REV	FUL	TOTAL			
PA Special Deductions												
TAX	PA SPECIAL DEDUCTIONS - TRANSMISSION RELATED	(90,437,000)	GNR_TRANS	-	-	-	-	-	-			
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELATED	(33,338,000)	DEPR_DPLT	(13,379,061)	(19,729,165)	(229,774)	-	-	(33,338,000)			
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)	DPLT	(447,632)	(452,368)	-	-	-	(900,000)			
TAX	FEDEARL TAX CREDIT - TRANS	(500,000)	GNR_TRANS	-	-	-	-	-	-			
TAX	FEDEARL TAX CREDIT - DIST	(900,000)	DPLT	(447,632)	(452,368)	-	-	-	(900,000)			
	TOTAL	(126,075,000)	-	(14,274,326)	(20,633,901)	(229,774)	-	-	(35,138,000)			
Net Addition:				-	(677,501,000)	0	(12,549,466)	(58,671,740)	(198,250,794)	-	-	(269,472,000)
Fuel and Purchased Power												
555	PURCHASED POWER	-	FUEL	-	-	-	-	-	-	-		
557	OTHER PURCHASED POWER EXPENSES	323,299	FUEL	-	-	-	-	323,299	-	323,299		
	TOTAL	323,299	0	-	-	-	-	323,299	-	323,299		
Income Taxes												
TAX	INCOME TAXES - STATE - PRESENT	(2,990,874)	INCTAX	-	-	7,457,701	-	-	-	7,457,701		
TAX	INCOME TAXES - FEDERAL - PRESENT	16,330,026	INCTAX	-	-	(40,718,685)	-	-	-	(40,718,685)		
TAX	INCOME TAXES - STATE - INCREASE	25,794,792	GNR_DIST	-	-	25,794,792	-	-	-	25,794,792		
TAX	INCOME TAXES - FEDERAL - INCREASE	69,402,242	GNR_DIST	-	-	69,402,242	-	-	-	69,402,242		
	TOTAL	108,536,187	0	-	-	61,936,051	-	-	-	61,936,051		
Operating Revenues												
REV	TRANSMISSION REVENUES	-	REV_TRANS	-	-	-	-	-	-	-		
REV	DISTRIBUTION REVENUES	1,004,890,414	REV_DIST	-	-	-	1,004,890,414	-	-	1,004,890,414		
REV	STATE TAX ADJ SURCHARGE	-	REV_DIST	-	-	-	-	-	-	-		
REV	LATE PAYMENT CHARGES	15,305,520	REV_DIST	-	-	-	15,305,520	-	-	15,305,520		
REV	ANNUALIZATION	4,932,874	REV_DIST	-	-	-	4,932,874	-	-	4,932,874		
REV	MISCELLANEOUS SERVICE REVS	969,910	REV_DIST	-	-	-	969,910	-	-	969,910		
REV	RENT-ELECTRIC PROPERTY - TRAN	2,916,000	REV_TRANS	-	-	-	-	-	-	-		
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268	REV_DIST	-	-	-	40,829,268	-	-	40,829,268		
REV	OTHER ELECTRIC REVENUE - TRAN	974,520,326	REV_TRANS	-	-	-	-	-	-	-		
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960	REV_DIST	-	-	-	3,024,960	-	-	3,024,960		
REV	RESALE REVENUES	318,877	REV_DIST	-	-	-	318,877	-	-	318,877		
REV	BL REVENUES	348,811	REV_DIST	-	-	-	348,811	-	-	348,811		
REV	LATE PAYMENT CHARGES INCREASE	1,699,050	REV_DIST	-	-	-	1,699,050	-	-	1,699,050		
	Sub-total	2,049,756,011	-	-	-	-	1,072,319,685	-	-	1,072,319,685		
	TOTAL	2,049,756,011		-	-	-	1,072,319,685	-	-	1,072,319,685		

**PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027**

**SECTION IV
RETAIL SERVICE CUSTOMERS – FUNCTIONALIZATION, CLASSIFICATION, AND
ALLOCATION**

This section shows the functionalization, classification, and allocation factors for each FERC account that ultimately constitutes the total revenue requirements. The second part of this section, after this description, provides details on the functionalization and classification of each account. In this part each account of the revenue requirement and the amount of dollars therein, is shown in the first column of costs. The other columns show the assignment of function, classification, and allocation factors to each cost item. Thus, one can see the amount of a particular account that is primary, secondary, customer, and demand.

Once the costs are functionalized and classified they are then allocated to rate classes. This is shown in the second part of this section and is broken into categories, such as rate base, depreciation, O&M expense, and taxes.

Lastly, a summary of the class allocation factors, both external and internal, that are utilized to allocate the functionalized and classified costs to rate classes is provided.

The primary secondary allocations and minimum system study as well as the allocation factors that support the results presented in this section are provided in Exhibit BE-2.

**Allocated Cost of Service Study
Cost Assignment Matrix**

Acct. No.	Account Description	Fully Projected Future Test Year	Fully Projected Future Test Year	Function	Classifier	DEM	CUS	FUL	REV	Internal
RATE BASE										
Plant-in Service										
Intangible Plant										
301-303	INTANGIBLE PLANT - DISTRIBUTION	670,295	670,295							LABOR
	Sub-total	670,295	670,295							
Distribution Plant										
360	LAND AND LAND RIGHTS	113,493,096	113,493,096							DPLT
360	LAND AND LAND RIGHTS - OVERHEAD LINES	-	-							PLT_365
361	STRUCTURES & IMPROVEMENTS	63,727,935	63,727,935	F DSTPR	DEM	PRI DEM				
362	STATION EQUIPMENT	1,071,977,540	1,071,977,540	F DSTPR	DEM	PRI DEM				
363	COMPUTER SOFTWARE & HARDWARE AND COMMUN	485,807,532	485,807,532							LABOR
364	POLES TOWERS & FIXTURES - PRI - DEMAND	537,975,079	537,975,079	F DSTPR	DEM	PRI DEM				
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	840,388,740	840,388,740	F DSTPR	CUS		PRI CUST			
364	POLES TOWERS & FIXTURES - SEC - DEMAND	100,896,363	100,896,363	F DSTSC	DEM	SEC DEM				
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	402,471,412	402,471,412	F DSTSC	CUS		SEC CUST			
365	OVERHEAD CONDUCTORS - PRI - DEMAND	764,864,095	764,864,095	F DSTPR	DEM	PRI DEM				
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	628,932,106	628,932,106	F DSTPR	CUS		PRI CUST			
365	OVERHEAD CONDUCTORS - SEC - DEMAND	436,593,319	436,593,319	F DSTSC	DEM	SEC DEM				
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	116,846,029	116,846,029	F DSTSC	CUS		SEC CUST			
366	UNDERGROUND CONDUIT - PRI - DEMAND	244,979,109	244,979,109	F DSTPR	DEM	PRI DEM				
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	116,349,939	116,349,939	F DSTPR	CUS		PRI CUST			
366	UNDERGROUND CONDUIT - SEC - DEMAND	11,950,350	11,950,350	F DSTSC	DEM	SEC DEM				
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	4,614,402	4,614,402	F DSTSC	CUS		SEC CUST			
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	644,919,075	644,919,075	F DSTPR	DEM	PRI DEM				
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	306,296,709	306,296,709	F DSTPR	CUS		PRI CUST			
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	31,459,861	31,459,861	F DSTSC	DEM	SEC DEM				
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	12,147,632	12,147,632	F DSTSC	CUS		SEC CUST			
368	LINE TRANSFORMERS - DEMAND	483,261,279	483,261,279	F TRANF	DEM	SEC DEM				
368	LINE TRANSFORMERS - CUSTOMER	285,488,986	285,488,986	F TRANF	CUS		SEC CUST			
369	SERVICES	846,971,069	846,971,069	F SERV	CUS		SERV			
370	METERS - DIST DIRECT	341,126,522	341,126,522	F METER	CUS		METERS			
371	INSTALLATIONS ON CUST PREMISES	15,029,035	15,029,035	F LIGHT	CUS		AREALGT			
373	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615	230,575,615	F LIGHT	CUS		STTRLGT			
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	621,595	621,595	F LIGHT	CUS		STTRLGT			
	Sub-total	9,139,764,425	9,139,764,425							
General Plant										
389-399	GENERAL PLANT - DISTRIBUTION	1,061,552,192	1,061,552,192							LABOR
	Sub-total	1,061,552,192	1,061,552,192							
	TOTAL PLANT-IN-SERVICE	10,201,986,912	10,201,986,912							
Accumulated Reserve for Depreciation										
Intangible Plant										
301-303	INTANGIBLE PLANT - DISTRIBUTION	-	-							LABOR
	Sub-total	-	-							
Distribution Plant										
360	LAND AND LAND RIGHTS	41,596,195	41,596,195							PLT_360
361	STRUCTURES & IMPROVEMENTS - PRIMARY	21,397,940	21,397,940	F DSTPR	DEM	PRI DEM				
362	STATION EQUIPMENT	234,310,665	234,310,665	F DSTPR	DEM	PRI DEM				
363	COMPUTER SOFTWARE & HARDWARE AND COMMUN	136,518,580	136,518,580							LABOR
364	POLES TOWERS & FIXTURES - PRI - DEMAND	155,736,214	155,736,214	F DSTPR	DEM	PRI DEM				
364	POLES TOWERS & FIXTURES - PRI - CUSTOMER	243,280,712	243,280,712	F DSTPR	CUS		PRI CUST			
364	POLES TOWERS & FIXTURES - SEC - DEMAND	29,208,077	29,208,077	F DSTSC	DEM	SEC DEM				
364	POLES TOWERS & FIXTURES - SEC - CUSTOMER	116,509,809	116,509,809	F DSTSC	CUS		SEC CUST			
365	OVERHEAD CONDUCTORS - PRI - DEMAND	155,012,771	155,012,771	F DSTPR	DEM	PRI DEM				
365	OVERHEAD CONDUCTORS - PRI - CUSTOMER	127,463,832	127,463,832	F DSTPR	CUS		PRI CUST			
365	OVERHEAD CONDUCTORS - SEC - DEMAND	88,483,092	88,483,092	F DSTSC	DEM	SEC DEM				
365	OVERHEAD CONDUCTORS - SEC - CUSTOMER	23,680,843	23,680,843	F DSTSC	CUS		SEC CUST			
366	UNDERGROUND CONDUIT - PRI - DEMAND	59,787,185	59,787,185	F DSTPR	DEM	PRI DEM				
366	UNDERGROUND CONDUIT - PRI - CUSTOMER	28,395,219	28,395,219	F DSTPR	CUS		PRI CUST			
366	UNDERGROUND CONDUIT - SEC - DEMAND	2,916,485	2,916,485	F DSTSC	DEM	SEC DEM				
366	UNDERGROUND CONDUIT - SEC - CUSTOMER	1,126,146	1,126,146	F DSTSC	CUS		SEC CUST			
367	UNDERGROUND CONDUCTORS - PRI - DEMAND	193,794,754	193,794,754	F DSTPR	DEM	PRI DEM				
367	UNDERGROUND CONDUCTORS - PRI - CUSTOMER	92,040,533	92,040,533	F DSTPR	CUS		PRI CUST			
367	UNDERGROUND CONDUCTORS - SEC - DEMAND	9,453,521	9,453,521	F DSTSC	DEM	SEC DEM				
367	UNDERGROUND CONDUCTORS - SEC - CUSTOMER	3,650,299	3,650,299	F DSTSC	CUS		SEC CUST			
368	LINE TRANSFORMERS - DEMAND	166,055,435	166,055,435	F TRANF	DEM	SEC DEM				
368	LINE TRANSFORMERS - CUSTOMER	98,098,068	98,098,068	F TRANF	CUS		SEC CUST			
369	SERVICES	430,314,690	430,314,690	F SERV	CUS		SERV			
370	METERS - DIST DIRECT	197,489,696	197,489,696	F METER	CUS		METERS			
371	INSTALLATIONS ON CUST PREMISES	8,531,974	8,531,974	F LIGHT	CUS		AREALGT			
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032	81,290,032	F LIGHT	CUS		STTRLGT			
364.4	STREET AND AREA LIGHTING PORTION OF 364.4	303,119	303,119	F LIGHT	CUS		STTRLGT			
	Sub-total	2,746,445,884	2,746,445,884							

**Allocated Cost of Service Study
Cost Assignment Matrix**

Acct. No.	Account Description	Fully Projected Future Test Year	Fully Projected Future Test Year	Function	Classifier	DEM	CUS	FUL	REV	Internal
General Plant										
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503	509,633,503							LABOR
	Sub-total	509,633,503	509,633,503							
	TOTAL DEPRECIATION ACCRUAL	3,256,079,387	3,256,079,387							
	NET PLANT	6,945,907,524	6,945,907,524							
Rate Base Adjustments										
Additions										
RB ADJ	PLANT HELD FOR FUTURE USE - DISTRIBUTION	-	-							TOTDPLT
RB ADJ	CASH WORKING CAPITAL - O&M	5,762,275	5,762,275							OMEXCLUNCOLL
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	19,449,818	19,449,818							TOTDPLT
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(15,007,233)	(15,007,233)							TOTDPLT
RB ADJ	MISCELLANEOUS PREPAYMENTS - DISTRIBUTION	6,257,237	6,257,237							TOTDPLT
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527	72,145,527							TOTDPLT
	Sub-total	88,607,624	88,607,624							
Deductions										
RB ADJ	CIAC - DISTRIBUTION	155,133,000	155,133,000							TOTDPLT
RB ADJ	CIAC - GENERAL	213,000	213,000							TOTDPLT
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)	(778,767,000)							TOTDPLT
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)	(96,296,000)							LABOR
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)	(500,288,000)							TOTDPLT
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000	12,833,000							LABOR
RB ADJ	CUSTOMER ADVANCES	-	-	F_DISTR	CUS		ADVANCES			
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)	(6,554,000)	F_DISTR	CUS		DEPOSIT			
	Sub-total	(1,213,726,000)	(1,213,726,000)							
	TOTAL RATE BASE ADJ.	(1,125,118,376)	(1,125,118,376)							
	TOTAL RATE BASE	5,820,789,148	5,820,789,148							

**Allocated Cost of Service Study
Cost Assignment Matrix**

Acct. No.	Account Description	Fully Projected Future Test Year	Fully Projected Future Test Year	Function	Classifier	DEM	CUS	FUL	REV	Internal
EXPENSES										
O & M Expenses										
Distribution Operation Expenses										
580	SUPERVISION AND ENGINEERING	10,367,332								DISTOPLBR
581	LOAD DISPATCHING	2,294,615								PLT_360_2
582	STATION EXPENSES	86,108								PLT_360_2
583	OVERHEAD LINES	29,067,041								PLT_364_5
584	UNDERGROUND LINES	6,594,454								PLT_366_7
585	STREET LIGHTING & SIGNAL SYSTEMS	-			F. LIGHT	CUS	STTRLGT			
586	METER EXPENSE	2,391,010			F. METER	CUS	METERS			
587	CUSTOMER INSTALLATION EXPENSE	3,025,958								PLT_369
588	MISC. DISTRIBUTION EXPENSE	18,180,878								DPLT
589	RENTS	7,534,350								DPLT
577-578	ENERGY STORAGE O&M	-								DPLT
PROFORMA	COMPANY USE OF GENERATION SUPPLY PURCHASE	1,359,000								LABOR
PROFORMA	WAGE AND BENEFITS ADJUSTMENT	(474,619)								LABOR
PROFORMA	RATE CASE EXPENSES	733,000								TOTPLT
PROFORMA	INTEREST EXPENSE ON CUSTOMER DEPOSITS	300,000			F. DISTR	CUS	DEPOSIT			
PROFORMA	ECONOMIC DEVELOPMENT PROPOSAL	400,000								TOTPLT
PROFORMA	COMPETITIVE ENHANCEMENT RIDER ROLL-IN TO BASE	-								TOTPLT
PROFORMA	DEFERRED STORM OUTAGE COSTS	3,779,000								TOTPLT
PROFORMA	IJA-RELATED INCREMENTAL EXPENDITURES	211,000								TOTPLT
PROFORMA	UNIVERSAL SERVICE RIDER (USR) SALARIES	(1,400,000)								TOTPLT
PROFORMA	CAPITAL TREATMENT OF IT EXPENDITURES	(1,826,000)								LABOR
Sub-total		82,623,129			82,623,129					
Distribution Maintenance Expenses										
590	SUPERVISION AND ENGINEERING	-								DMAINTLBR
591	STRUCTURES	137,306								PLT_360_2
592	STATION EQUIPMENT	12,304,925								PLT_360_2
593	OVERHEAD LINES	85,378,325								PLT_364_5
593.5	OVERHEAD LINES - SERVICES - DEMAND	-			F. SERVS	DEM	SRV DEM			
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	25,336,746			F. SERVS	CUS	SERV			
594	UNDERGROUND LINES	340,244								PLT_366_7
595	LINE TRANSFORMERS - DEMAND	114,589			F. TRANF	DEM	SEC DEM			
595	LINE TRANSFORMERS - CUSTOMER	67,694			F. TRANF	CUS	SEC CUST			
596	STREET LIGHT & SIGNAL SYSTEMS	2,424,105			F. LIGHT	CUS	STTRLGT			
597	METERS	-			F. METER	CUS	METERS			
598	MISCELLANEOUS DISTRIB. PLANT	2,066,606								DPLT
Sub-total		128,170,541			128,170,541					
Total Distribution		210,793,669			210,793,669					
Customer Account										
901	SUPERVISION	4,016,323			4,016,323					CUSTACCTLBR
902	METER READING	1,205,576			1,205,576	F. METRD	CUS	MTREAD		
903CR	CUSTOMER RECORDS	25,189,595			25,189,595	F. BILLS	CUS	CUST		
903CE	COLLECTION EXPENSES	14,177,408			14,177,408	F. BILLS	CUS	GRSWRTOFF		
904 D	PROPERTY DAMAGE DISTRIBUTION	4,220,000			4,220,000					TOTDPLT
904 by RATE	UNCOLLECTIBLE ACCOUNTS	32,845,983			32,845,983	F. CUSSV	CUS	GRSWRTOFF		
905	MISC. CUSTOMER ACCOUNTS EXPENSES	3,588,596			3,588,596	F. BILLS	CUS	CUST		
904	UNCOLLECTIBLE ACCOUNT INCREASE	6,421,504			6,421,504	F. CUSSV	CUS	GRSWRTOFF		
904-MFC	MFC ADJUSTMENT (@ Present Rates)	(18,111,000)			(18,111,000)	F. CUSSV	CUS	GRSWRTOFF		
Sub-total		73,553,985			73,553,985					
Customer Service & Information Expenses										
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-			-	F. CUSSV	CUS	CUST		
908 Other - 911	OTHER CUSTOMER SERVICE AND INFORMATION	22,026,873			22,026,873	F. CUSSV	CUS	CUST		
Sub-total		22,026,873			22,026,873					
Sales Expenses										
911-916	SALES EXPENSES	-			-	F. CUSSV	CUS	CUST		
Sub-total		-			-					

**Allocated Cost of Service Study
Cost Assignment Matrix**

Cost Assignment Matrix			Fully Projected Future		Fully Projected							
Acct. No.	Account Description	Test Year	Future Test Year	Function	Classifier	DEM	CUS	FUL	REV	Internal		
Administrative and General Expenses												
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572				86,305,572				LABOR		
924	PROPERTY INSURANCE - DIST	2,058,405				2,058,405				TOTDPLT		
925	INJURIES & DAMAGES - DIST	6,965,752				6,965,752				LABOR		
926	EMPLOYEE BENEFITS - DIST	2,395,082				2,395,082				LABOR		
927	FRANCHISE REQUIREMENTS - DIST	-				-				NETTOTPLT		
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737				6,663,737				NETTOTPLT		
928F	REGULATORY COMMISSION EXPENSE - FERC - DIST	-				-				NETTOTPLT		
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)				(12,885,859)				TOTDPLT		
933	TRANSPORTATION EXPENSES - DIST	916,027				916,027				LABOR		
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748				38,427,748				LABOR		
928	PUC FEE INCREASE	1,110,654				1,110,654				NETTOTPLT		
	Sub-total	131,957,117				131,957,117						
	TOTAL O & M EXPENSES	438,331,644				438,331,644						
Labor Expense												
Distribution Operation Expenses												
580	SUPERVISION AND ENGINEERING	2,531,568				2,531,568				DISTOPLBR		
581	LOAD DISPATCHING	205,354				205,354				PLT_360_2		
582	STATION EXPENSES	63,106				63,106				PLT_360_2		
583	OVERHEAD LINES	11,129,059				11,129,059				PLT_364_5		
584	UNDERGROUND LINES	1,412,410				1,412,410				PLT_366_7		
585	STREET LIGHTING & SIGNAL SYSTEMS	-				-	F LIGHT	CUS	STTRLGT			
586	METER EXPENSE	1,774,160				1,774,160	F METER	CUS	METERS			
587	CUSTOMER INSTALLATION EXPENSE	1,484,627				1,484,627				PLT_369		
588	MISC. DISTRIBUTION EXPENSE	2,505,643				2,505,643				DPLT		
589	RENTS	-				-				DPLT		
577-578	ENERGY STORAGE O&M	-				-				DPLT		
	Sub-total	21,105,928				21,105,928						
Distribution Maintenance Expenses												
590	SUPERVISION AND ENGINEERING	-				-				DMAINTLBR		
591	STRUCTURES	-				-				PLT_360_2		
592	STATION EQUIPMENT	1,261,242				1,261,242				PLT_360_2		
593	OVERHEAD LINES	9,796,738				9,796,738				PLT_364_5		
593.5	OVERHEAD LINES - SERVICES - DEMAND	-				-	F SERVS	DEM	SRV_DEM			
593.5	OVERHEAD LINES - SERVICES - CUSTOMER	-				-	F SERVS	CUS	SERV			
594	UNDERGROUND LINES	55,053				55,053				PLT_366_7		
594.3 & 594.6	UNDERGROUND LINES - SERVICES - DEMAND	-				-	F SERVS	DEM	SRV_DEM			
594.3 & 594.6	UNDERGROUND LINES - SERVICES - CUSTOMER	-				-	F SERVS	CUS	SERV			
595	LINE TRANSFORMERS - DEMAND	-				-	F TRANF	DEM	SEC_DEM			
595	LINE TRANSFORMERS - CUSTOMER	-				-	F TRANF	CUS	SEC_CUST			
596	STREET LIGHT & SIGNAL SYSTEMS	739,646				739,646	F LIGHT	CUS	STTRLGT			
597	METERS	112,216				112,216	F METER	CUS	METERS			
598	MISCELLANEOUS DISTRIB. PLANT	-				-				DPLT		
	Sub-total	11,964,895				11,964,895						
	Total Distribution	33,070,822				33,070,822						
Customer Account												
901	SUPERVISION	3,084,792				3,084,792	F METRD	CUS	MTREAD	CUSTACCTLBR		
902	METER READING	1,205,576				1,205,576	F BILLS	CUS	CUST			
903CR	CUSTOMER RECORDS	15,198,749				15,198,749	F BILLS	CUS	GRSWRTOFF			
903CE	COLLECTION EXPENSES	-				-				TOTDPLT		
904 D	PROPERTY DAMAGE DISTRIBUTION	-				-						
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-				-	F CUSSF	CUS	GRSWRTOFF			
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080				147,080	F BILLS	CUS	CUST			
	Sub-total	19,636,197				19,636,197						
Customer Service & Information Expenses												
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-				-	F CUSSF	CUS	CUST			
908 Other - 911	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759				10,495,759	F CUSSF	CUS	CUST			
	Sub-total	10,495,759				10,495,759						
Sales Expenses												
911-916	SALES EXPENSES	-				-	F CUSSF	CUS	CUST			

**Allocated Cost of Service Study
Cost Assignment Matrix**

Acct. No.	Account Description	Fully Projected Future Test Year	Fully Projected Future Test Year	Function	Classifier	DEM	CUS	FUL	REV	Internal
	Sub-total	-	-							
	TOTAL O & M LABOR EXP.	63,202,778	63,202,778							

Depreciation Expense

Intangible Plant										
301-303	INTANGIBLE PLANT - DISTRIBUTION	-			-					LABOR
301-303	INTANGIBLE PLANT - PRO FORMA	-			-					LABOR
	Sub-total	-			-					
Distribution Plant										
360	LAND AND LAND RIGHTS	756,214			756,214					PLT_360
361	STRUCTURES & IMPROVEMENTS	814,601			814,601					PLT_360_1
362	STATION EQUIPMENT	20,033,725			20,033,725					PLT_362
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNIC	66,278,524			66,278,524					LABOR
364	POLES TOWERS & FIXTURES	42,177,610			42,177,610					PLT_364
365	OVERHEAD CONDUCTORS	45,318,655			45,318,655					PLT_365
366	UNDERGROUND CONDUIT	5,494,850			5,494,850					PLT_366
367	UNDERGROUND CONDUCTORS	17,061,472			17,061,472					PLT_367
368	LINE TRANSFORMERS - DEMAND	14,566,138			14,566,138	F_TRANF	DEM	SEC_DEM		
368	LINE TRANSFORMERS - CUSTOMER	8,605,018			8,605,018	F_TRANF	CUS		SEC_CUST	
369	SERVICES	9,866,936			9,866,936	F_SERVS	CUS		SERV	
370	METERS	26,031,923			26,031,923	F_METER	CUS		METERS	
371	INSTALLATIONS ON CUST PREMISES	476,054			476,054	F_LIGHT	CUS		AREALGT	
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971			5,594,971	F_LIGHT	CUS		STTRLGT	
387	ENERGY STORAGE EQUIPMENT	42,520			42,520					TOTDPLT
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000			1,826,000					LABOR
	Sub-total	264,935,209			264,935,209					
General Plant Plant										
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699			59,220,699					LABOR
389-399	GENERAL PLANT - PRO FORMA	-			-					LABOR
	Sub-total	59,220,699			59,220,699					
	TOTAL DEPRECIATION EXPENSES	324,155,908			324,155,908					

Amortization

Other										
AMORT	AMORTIZATION - 2005 ICE STORM DEFERRAL	-			-					TOTDPLT
AMORT	AMORTIZATION OF 2010 RATE CASE EXPENSE	-			-					TOTDPLT
AMORT	AMORTIZATION - 2011 STORM DEFERRAL	-			-					TOTDPLT
	Sub-total	-			-					
	TOTAL AMORTIZATION EXPENSES	-			-					

Taxes Other Than Income Taxes

TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)			(2,515,000)					DPLT
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)			(102,000)					TOTPLT
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000			25,863,000					DPLT
TAX	DEFERRED TAXES - GROSS REVENUE TAXES	-			-					TOTPLT
TAX	DEFERRED TAXES - LABOR	23,224,000			23,224,000					LABOR
TAX	DEFERRED TAXES - MATERIALS AND SUPPLIES	-			-					TOTPLT
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000			2,460,000					TOTPLT
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000			1,500,000					TOTPLT
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)			(15,000)					DPLT
TAX	OTHER TAXES - DISTRIBUTION	-			-					DPLT
TAX	OTHER TAXES - ELECTRIC PLANT	-			-					TOTPLT
TAX	OTHER TAXES - DISTRIBUTION PLANT	-			-					DPLT
TAX	OTHER TAXES - LABOR	4,862,000			4,862,000					LABOR
TAX	GROSS RECEIPTS TAX	56,151,000			56,151,000					TOTPLT
TAX	GROSS RECEIPTS TAX - INCREASE	22,406,453			22,406,453					TOTPLT
	Sub-total	133,834,453			133,834,453					
	TOTAL TAXES OTHER THAN INCOME TAX	133,834,453			133,834,453					

**Allocated Cost of Service Study
Cost Assignment Matrix**

Cost Assignment Matrix			Fully Projected Future		Fully Projected Future		Function	Classifier	DEM	CUS	FUL	REV	Internal
Acct. No.	Account Description	Test Year			Test Year								
Adjustments to Taxable Income													
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)			(203,479,000)								TOTPLT
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000			5,160,000								DEPR
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000			43,234,000								DEPR_DPLT
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)			(94,877,000)								DEPR_GIPLT
TAX	TAX ADJUSTMENT - DISTRIBUTION PLANT RELATED	-			-								DPLT
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000			376,000								DPLT
TAX	TAX ADJUSTMENT - GRT RELATED	-			-								
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000			15,252,000								LABOR
TAX	TAX ADJUSTMENT - M&S RELATED	-			-								LABOR
TAX	TAX ADJUSTMENT - PRO FORMA G&I DEPRECIATION R	-			-								DEPR_GIPLT
	Sub-total	(234,334,000)			(234,334,000)								
PA Special Deductions													
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELAT	(33,338,000)			(33,338,000)								DEPR_DPLT
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)			(900,000)								DPLT
TAX	PA SPECIAL DEDUCTIONS - DISTRIBUTION PLANT RELAT	-			-								DPLT
TAX	PA SPECIAL DEDUCTIONS - G&I DEPRECIATION RELATI	-			-								DEPR_GIPLT
TAX	PA SPECIAL DEDUCTIONS - FEDERAL NOL	-			-								DPLT
TAX	FEDEARL TAX CREDIT - DIST	(900,000)			(900,000)								DPLT
	TOTAL	(35,138,000)			(35,138,000)								
Net Adds/Deducts to Taxable Income		(269,472,000)			(269,472,000)								
Fuel and Purchased Power													
555	PURCHASED POWER	-			-	F PRPWR	FUL				FUL ENRGYSRC		
557	OTHER PURCHASED POWER EXPENSES	323,299			323,299	F PRPWR	FUL				FUL ENRGYSRC		
	TOTAL	323,299			323,299								
Income Taxes													
	TOTAL	-			-								
Operating Revenues													
REV	DISTRIBUTION REVENUES	1,004,890,414			1,004,890,414	F REVNU	REV					REV_DIST	
REV	STATE TAX ADJ SURCHARGE	-			-	F REVNU	REV					REV_STAS	
REV	LATE PAYMENT CHARGES	15,305,520			15,305,520	F REVNU	REV					LT_FEES	
REV	ANNUALIZATION	4,932,874			4,932,874	F REVNU	REV					REV_ANNL	
REV	MISCELLANEOUS SERVICE REVS	969,910			969,910	F REVNU	REV					REV_TOTDPLT	
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268			40,829,268	F REVNU	REV					REV_TOTDPLT	
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960			3,024,960	F REVNU	REV					REV_TOTDPLT	
REV	RESALE & BL REVENUES	318,877			318,877	F REVNU	REV					REV_DIST	
REV	BL REVENUES	348,811			348,811	F REVNU	REV					REV_DIST	
REV	LATE PA PAYMENT CHARGES INCREASE	1,699,050			1,699,050	F REVNU	REV					LT_FEES	
	Sub-total	1,072,319,685			1,072,319,685								
	TOTAL	1,072,319,685			1,072,319,685								

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
RATE BASE													
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	2,285,442,224	-	1,236,298,392	29,972,963	128,825,466	546,987,056	334,149,689	-	5,429,276
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	430,481,630	-	272,744,213	6,612,443	28,420,647	120,672,772	-	-	1,197,772
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	267,367,498	-	169,398,490	4,106,917	17,651,757	74,948,558	-	-	743,923
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	1,318,323,288	-	1,140,054,908	10,139,020	129,257,810	34,930,213	1,084,253	-	1,561,941
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	373,664,268	-	323,402,034	2,876,159	36,666,864	9,908,735	-	-	443,079
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	157,948,669	-	136,702,718	1,215,759	15,499,160	4,188,443	-	-	187,291
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	350,430,007	-	264,794,218	2,354,934	47,397,810	35,408,127	-	-	-
F_METER	CUS	Meters	F_METER_CUS	METERS	133,245,643	-	84,027,333	837,205	15,262,834	23,362,406	6,325,414	3,096,761	333,691
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	4,947,023	-	-	-	-	-	-	-	4,947,023
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	134,917,939	-	-	-	-	-	-	-	134,917,939
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	(6,549,668)	-	(1,978,080)	(12,424)	(1,531,377)	(2,856,893)	(109,210)	-	(47,178)
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	17,575,718	-	15,215,413	135,317	1,725,102	466,186	14,471	1,944	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	223,916,091	-	193,615,969	1,721,914	21,951,904	5,932,212	184,139	24,734	265,265
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	204,714	-	186,365	632	7,675	8,609	1,336	55	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	(261,513)	-	(238,073)	(808)	(9,805)	(10,998)	(1,707)	(70)	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	129,135,614	-	111,661,100	993,052	12,659,977	3,421,191	106,196	14,264	152,982
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
RATE BASE					-	-	-	-	-	-	-	-	-
			DEM		-	2,983,291,352	1,678,441,094	40,692,322	174,897,871	742,608,386	334,149,689	-	7,370,971
			CUS		-	2,837,497,796	2,267,443,903	20,260,760	278,887,956	114,758,231	7,604,892	3,137,688	142,428,343
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		-	5,820,789,148	3,945,884,998	60,953,083	453,785,827	857,366,617	341,754,581	3,137,688	149,799,315

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Plant-in Service					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	3,640,047,852	-	1,969,065,443	47,738,253	205,181,674	871,192,034	532,203,721	-	8,647,265
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	672,599,979	-	426,145,366	10,331,518	44,405,441	188,543,479	-	-	1,871,442
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	493,407,427	-	312,612,690	7,579,019	32,575,045	138,312,155	-	-	1,372,857
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	2,158,153,523	-	1,866,320,301	16,598,023	211,600,752	57,182,303	1,774,970	-	2,556,967
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	623,394,595	-	539,540,698	4,798,377	61,172,360	16,531,021	-	-	739,202
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	291,482,873	-	252,275,002	2,243,595	28,602,582	7,729,469	-	-	345,631
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	906,635,362	-	685,077,751	6,092,704	122,627,999	91,608,195	-	-	-
F_METER	CUS	Meters	F_METER_CUS	METERS	398,338,383	-	251,200,047	2,502,827	45,628,304	69,842,005	18,909,852	9,257,779	997,570
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	15,344,572	-	-	-	-	-	-	-	-
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	254,504,655	-	-	-	-	-	-	-	15,344,572
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	254,504,655
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-	-	-	-	-	-	-
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	35,508,831	-	30,740,225	273,387	3,485,283	941,852	29,236	3,927	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	451,993,573	-	390,830,213	3,475,828	44,311,776	11,974,671	371,700	49,928	535,460
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	260,575,284	-	225,314,473	2,003,823	25,545,836	6,903,424	214,286	28,783	308,694
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
Plant-in Service					-	-	-	-	-	-	-	-	-
			DEM	-	4,806,055,258	-	2,707,823,499	65,648,790	282,162,160	1,198,047,668	532,203,721	-	11,891,564
			CUS	-	5,395,931,654	-	4,241,298,709	37,988,564	542,974,892	262,712,940	21,300,044	9,340,417	274,335,181
			FUL	-	-	-	-	-	-	-	-	-	-
			REV	-	-	-	-	-	-	-	-	-	-
			TOTAL	-	10,201,986,912	-	6,949,122,208	103,637,354	825,137,052	1,460,760,608	553,503,765	9,340,417	286,226,745

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Accumulated Reserve for Depreciation					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	947,920,423	-	512,772,750	12,431,723	53,432,237	226,870,842	138,593,446	-	2,251,871
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	167,948,433	-	106,408,636	2,579,783	11,088,053	47,079,368	-	-	467,300
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	169,980,400	-	107,696,049	2,610,996	11,222,205	47,648,970	-	-	472,953
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	601,027,887	-	519,754,751	4,622,412	58,929,057	15,924,798	494,314	-	712,094
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	181,053,505	-	156,699,681	1,393,601	17,766,388	4,801,131	-	-	214,688
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	100,416,761	-	86,909,526	772,925	9,853,679	2,662,826	-	-	119,071
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	454,666,931	-	343,558,404	3,055,419	61,496,494	45,940,428	-	-	-
F_METER	CUS	Meters	F_METER_CUS	METERS	221,141,206	-	139,456,009	1,389,468	25,330,971	38,773,429	10,497,978	5,139,541	-
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	8,654,037	-	-	-	-	-	-	-	8,654,037
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	91,169,714	-	-	-	-	-	-	-	91,169,714
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-	-	-	-	-	-	-
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	14,814,383	-	12,824,907	114,058	1,454,070	392,943	12,197	1,638	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	188,572,975	-	163,055,451	1,450,125	18,486,996	4,995,866	155,074	20,830	223,395
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	108,712,732	-	94,001,824	836,000	10,657,794	2,880,128	89,401	12,009	128,788
F_PRPW	FUL	Purchased Power	F_PRPW_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
Accumulated Reserve for Depreciation					-	-	-	-	-	-	-	-	-
			DEM		-	1,285,849,257	726,877,435	17,622,502	75,742,495	321,599,180	138,593,446	-	3,192,124
			CUS		-	1,970,230,130	1,516,260,553	13,634,008	203,975,449	116,371,550	11,248,964	5,174,018	101,221,788
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		-	3,256,079,387	2,243,137,989	31,256,509	279,717,944	437,970,730	149,842,411	5,174,018	104,413,912

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Rate Base Adjustments					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	(406,685,204)	(219,994,301)	(5,333,568)	(22,923,971)	(97,334,135)	(59,460,586)	-	(672,526)	(966,118)
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	(74,169,915)	(46,992,517)	(1,139,292)	(4,896,741)	(20,791,338)	-	-	(143,657)	(206,370)
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	(56,059,528)	(35,518,152)	(861,106)	(3,701,083)	(15,714,628)	-	-	(108,579)	(155,980)
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	(238,802,348)	(206,510,642)	(1,836,592)	(23,413,884)	(6,327,292)	(196,403)	-	(234,604)	(282,932)
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	(68,676,823)	(59,438,983)	(528,618)	(6,739,108)	(1,821,155)	-	-	(67,525)	(81,435)
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	(33,117,443)	(28,662,758)	(254,911)	(3,249,743)	(878,200)	-	-	(32,562)	(39,270)
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	(101,538,424)	(76,725,129)	(682,351)	(13,733,695)	(10,259,639)	-	-	(137,610)	-
F_METER	CUS	Meters	F_METER_CUS	METERS	(43,951,534)	(27,716,705)	(276,155)	(5,034,498)	(7,706,170)	(2,086,460)	(1,021,477)	(110,069)	-
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	(1,743,512)	-	-	-	-	-	-	-	(1,743,512)
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	(28,417,001)	-	-	-	-	-	-	-	(28,417,001)
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	(6,549,668)	(1,978,080)	(12,424)	(1,531,377)	(2,856,893)	(109,210)	-	(14,506)	(47,178)
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	(3,118,730)	(2,699,905)	(24,011)	(306,111)	(82,723)	(2,568)	(345)	(3,067)	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	(39,504,507)	(34,158,793)	(303,789)	(3,872,876)	(1,046,593)	(32,487)	(4,364)	(38,806)	(46,800)
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	204,714	186,365	632	7,675	8,609	1,336	55	42	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	(261,513)	(238,073)	(808)	(9,805)	(10,998)	(1,707)	(70)	(54)	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	(22,726,938)	(19,651,549)	(174,770)	(2,228,065)	(602,105)	(18,690)	(2,510)	(22,325)	(26,924)
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
Rate Base Adjustments					-	-	-	-	-	-	-	-	-
			DEM		(536,914,648)	(302,504,969)	(7,333,966)	(31,521,794)	(133,840,102)	(59,460,586)	-	(924,762)	(1,328,468)
			CUS		(588,203,728)	(457,594,252)	(4,093,796)	(60,111,487)	(31,583,159)	(2,446,187)	(1,028,711)	(661,084)	(30,685,050)
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		(1,125,118,376)	(760,099,222)	(11,427,762)	(91,633,282)	(165,423,261)	(61,906,774)	(1,028,711)	(1,585,846)	(32,013,518)

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
O & M EXPENSES					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	93,100,286	50,362,128	1,220,985	5,247,863	22,282,187	13,611,997	-	153,958	221,168
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	27,081,686	17,158,393	415,990	1,787,949	7,591,548	-	-	52,453	75,352
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	2,283,012	1,446,469	35,068	150,726	639,975	-	-	4,422	6,352
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	77,900,331	67,366,371	599,119	7,637,904	2,064,042	64,069	-	76,531	92,296
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	25,811,486	22,339,538	198,676	2,532,825	684,462	-	-	25,379	30,606
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	1,348,700	1,167,284	10,381	132,345	35,764	-	-	1,326	1,599
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	36,638,585	27,685,087	246,216	4,955,594	3,702,034	-	-	49,654	-
F_METER	CUS	Meters	F_METER_CUS	METERS	9,366,396	5,906,634	58,851	1,072,889	1,642,242	444,640	217,684	23,457	-
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	63,667	-	-	-	-	-	-	-	63,667
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	5,154,175	-	-	-	-	-	-	-	5,154,175
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	300,000	90,604	569	70,143	130,857	5,002	-	664	2,161
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	4,722,178	4,088,020	36,357	463,494	125,253	3,888	522	4,644	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	73,541,181	63,589,655	565,531	7,209,705	1,948,327	60,477	8,123	72,240	87,121
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	14,177,408	12,906,629	43,785	531,541	596,218	92,533	3,781	2,922	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	21,156,487	19,260,145	65,338	793,201	889,717	138,083	5,642	4,360	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	45,686,066	39,503,869	351,326	4,478,893	1,210,361	37,570	5,047	44,878	54,123
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
O & M EXPENSES					-	-	-	-	-	-	-	-	-
			DEM		122,464,984	68,966,990	1,672,044	7,186,537	30,513,710	13,611,997	-	210,833	302,873
			CUS		315,866,660	263,903,836	2,176,148	29,878,532	13,029,278	846,263	240,799	306,055	5,485,749
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		438,331,644	332,870,826	3,848,192	37,065,070	43,542,989	14,458,259	240,799	516,888	5,788,621

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Depreciation Expense					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	82,234,162	44,484,153	1,078,479	4,635,363	19,681,540	12,023,283	-	135,989	195,355
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	20,477,135	12,973,887	314,540	1,351,912	5,740,158	-	-	39,661	56,976
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	14,986,803	9,495,327	230,206	989,437	4,201,106	-	-	29,027	41,699
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	61,530,666	53,210,270	473,223	6,032,905	1,630,313	50,606	-	60,449	72,901
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	19,020,045	16,461,625	146,401	1,866,396	504,369	-	-	18,701	22,553
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	8,853,528	7,662,624	68,147	868,777	234,776	-	-	8,705	10,498
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	14,205,730	10,734,227	95,464	1,921,412	1,435,375	-	-	19,252	-
F_METER	CUS	Meters	F_METER_CUS	METERS	30,632,766	19,317,627	192,471	3,508,879	5,370,946	1,454,193	711,936	76,714	-
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	489,136	-	-	-	-	-	-	-	489,136
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	7,397,002	-	-	-	-	-	-	-	7,397,002
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-	-	-	-	-	-	-
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	3,053,487	2,643,423	23,509	299,708	80,992	2,514	338	3,003	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	38,867,976	33,608,396	298,895	3,810,472	1,029,730	31,963	4,293	38,180	46,045
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	22,407,473	19,375,314	172,313	2,196,746	593,641	18,427	2,475	22,011	26,545
F_PRPW	FUL	Purchased Power	F_PRPW_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
Depreciation Expense					-	-	-	-	-	-	-	-	-
			DEM		117,698,100	66,953,367	1,623,225	6,976,713	29,622,804	12,023,283	-	204,677	294,030
			CUS		206,457,808	163,013,507	1,470,423	20,505,295	10,880,140	1,557,704	719,042	247,016	8,064,681
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		324,155,908	229,966,874	3,093,648	27,482,008	40,502,945	13,580,987	719,042	451,693	8,358,711

Allocated Cost of Service Study
Functionalization and Classification of Costs

Allocated Cost of Service Study					Line Ref.	6	7	8	9	10	11	12	13	
Functionalization and Classification of Costs							Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL	
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS								
Taxes Other Than Income Taxes					-	-	-	-	-	-	-	-	-	
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	43,102,629	-	23,316,149	565,279	2,429,603	10,315,982	6,301,944	-	71,278	102,394
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	8,528,526	-	5,403,497	131,003	563,058	2,390,720	-	-	16,519	23,730
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	5,312,001	-	3,365,574	81,595	350,701	1,489,062	-	-	10,289	14,780
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	26,901,531	-	23,263,810	206,895	2,637,618	712,781	22,125	-	26,429	31,873
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	7,943,018	-	6,874,588	61,139	779,431	210,631	-	-	7,810	9,419
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	3,138,091	-	2,715,981	24,154	307,934	83,215	-	-	3,085	3,721
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	10,438,956	-	7,887,952	70,151	1,411,933	1,054,772	-	-	14,147	-
F_METER	CUS	Meters	F_METER_CUS	METERS	5,098,910	-	3,215,474	32,037	584,063	894,009	242,055	118,504	12,769	-
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	165,199	-	-	-	-	-	-	-	-	165,199
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	3,038,787	-	-	-	-	-	-	-	-	3,038,787
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-	-	-	-	-	-	-	-
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	957,253	-	828,700	7,370	93,957	25,391	788	106	941	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	12,184,919	-	10,536,067	93,702	1,194,564	322,815	10,020	1,346	11,969	14,435
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	7,024,633	-	6,074,066	54,019	688,669	186,104	5,777	776	6,900	8,322
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-	-
Taxes Other Than Income Taxes					-	-	-	-	-	-	-	-	-	
			DEM		56,943,155	-	32,085,219	777,878	3,343,362	14,195,763	6,301,944	-	98,085	140,904
			CUS		76,891,298	-	61,396,639	549,469	7,698,169	3,489,718	280,765	120,732	84,052	3,271,755
			FUL		-	-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-	-
			TOTAL		133,834,453	-	93,481,857	1,327,346	11,041,531	17,685,482	6,582,709	120,732	182,137	3,412,659

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Adjustments to Taxable Income					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	(73,228,196)	-	(39,612,421)	(960,368)	(4,127,716)	(17,526,094)	(10,706,540)	(121,096)	(173,960)
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	(14,570,930)	-	(9,231,838)	(223,818)	(961,981)	(4,084,529)	-	(28,222)	(40,542)
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	(7,370,449)	-	(4,669,763)	(113,214)	(486,601)	(2,066,087)	-	(14,276)	(20,508)
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	(45,868,318)	-	(39,665,841)	(352,766)	(4,497,257)	(1,215,324)	(37,724)	(45,062)	(54,344)
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	(13,632,867)	-	(11,799,086)	(104,935)	(1,337,764)	(361,513)	-	(13,404)	(16,165)
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	(4,354,129)	-	(3,768,447)	(33,514)	(427,261)	(115,462)	-	(4,281)	(5,163)
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	(18,318,653)	-	(13,842,060)	(123,104)	(2,477,710)	(1,850,952)	-	(24,826)	-
F_METER	CUS	Meters	F_METER_CUS	METERS	(5,484,019)	-	(3,458,330)	(34,457)	(628,176)	(961,531)	(260,336)	(13,734)	-
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	(225,085)	-	-	-	-	-	(127,454)	-	(225,085)
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	(4,913,422)	-	-	-	-	-	-	-	(4,913,422)
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-	-	-	-	-	-	-
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	(2,200,936)	-	(1,905,365)	(16,945)	(216,028)	(58,379)	(1,812)	(243)	-
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	(28,015,817)	-	(24,224,742)	(215,441)	(2,746,567)	(742,223)	(23,039)	(3,095)	(27,520)
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	(16,151,180)	-	(13,965,617)	(124,202)	(1,583,402)	(427,893)	(13,282)	(15,865)	(19,134)
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
Adjustments to Taxable Income					-	-	-	-	-	-	-	-	-
			DEM		(95,169,574)	-	(53,514,023)	(1,297,400)	(5,576,299)	(23,676,709)	(10,706,540)	(163,593)	(235,010)
			CUS		(139,164,426)	-	(112,629,489)	(1,005,365)	(13,914,164)	(5,733,278)	(336,194)	(132,576)	(146,857)
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		(234,334,000)	(166,143,512)	(2,302,765)	(19,490,463)	(29,409,987)	(11,042,734)	(132,576)	(310,450)	(5,501,513)

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
PA Special Deductions					-	-	-	-	-	-	-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	(9,735,007)	-	(5,266,103)	(127,672)	(548,741)	(2,329,931)	(1,423,335)	-	(23,126)
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	(2,293,159)	-	(1,452,898)	(35,224)	(151,396)	(642,819)	-	-	(6,380)
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	(1,962,968)	-	(1,243,696)	(30,152)	(129,596)	(550,260)	-	-	(5,462)
F_SERVS	DEM	#N/A	F_SERVS_DEM	SRV_DEM	-	-	-	-	-	-	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	(6,972,804)	-	(6,029,917)	(53,627)	(683,663)	(184,751)	(5,735)	-	(8,261)
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	(2,118,954)	-	(1,833,930)	(16,310)	(207,928)	(56,190)	-	-	(2,513)
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	(1,159,633)	-	(1,003,649)	(8,926)	(113,792)	(30,751)	-	-	(1,375)
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SERV	(1,724,505)	-	(1,303,082)	(11,589)	(233,250)	(174,247)	-	-	-
F_METER	CUS	Meters	F_METER_CUS	METERS	(3,672,224)	-	(2,315,777)	(23,073)	(420,641)	(643,863)	(174,327)	(85,346)	(9,196)
F_LIGHT	CUS	Area Lighting	F_LIGHT_CUS	AREALGT	(63,948)	-	-	-	-	-	-	-	(63,948)
F_LIGHT	CUS	Street Lighting	F_LIGHT_CUS	STTRLGT	(880,356)	-	-	-	-	-	-	-	(880,356)
F_DISTR	-	Customer Advances	F_DISTR_0	ADVANCES	-	-	-	-	-	-	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-	-	-	-	-	-	-
F_METRD	CUS	Meter Reading	F_METRD_CUS	MTREAD	(216,185)	-	(187,152)	(1,664)	(21,219)	(5,734)	(178)	(24)	(213)
F_BILLS	CUS	Billing, Records, and Collecting	F_BILLS_CUS	CUST	(2,751,825)	-	(2,379,450)	(21,162)	(269,779)	(72,904)	(2,263)	(304)	(3,260)
F_BILLS	CUS	Collection Expense	F_BILLS_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Uncollectible and MFC	F_CUSSV_CUS	GRSWRTOFF	-	-	-	-	-	-	-	-	-
F_CUSSV	CUS	Customer Service	F_CUSSV_CUS	CUST	(1,586,433)	-	(1,371,758)	(12,200)	(155,528)	(42,029)	(1,305)	(175)	(1,879)
F_PRPW	FUL	Purchased Power	F_PRPW_FUL	FUL_ENRGYSRC	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-	-	-	-	-	-	-
F_REVNU	REV	State Tax Surcharge	F_REVNU_REV	REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Late Payment Fees	F_REVNU_REV	LT_FEES	-	-	-	-	-	-	-	-	-
F_REVNU	REV	Annualization	F_REVNU_REV	REV_ANNL	-	-	-	-	-	-	-	-	-
PA Special Deductions					-	-	-	-	-	-	-	-	-
			DEM		(13,991,133)	-	(7,962,696)	(193,049)	(829,733)	(3,523,010)	(1,423,335)	-	(34,969)
			CUS		(21,146,867)	-	(16,424,715)	(148,550)	(2,105,800)	(1,210,470)	(183,808)	(85,849)	(961,592)
			FUL		-	-	-	-	-	-	-	-	-
			REV		-	-	-	-	-	-	-	-	-
			TOTAL		(35,138,000)	(24,387,411)	(341,599)	(2,935,534)	(4,733,480)	(1,607,142)	(85,849)	(50,424)	(996,561)

Allocated Cost of Service Study
Functionalization and Classification of Costs

					Line Ref.	6	7	8	9	10	11	12	13
Function	Class	Functional Description	Func/Class	Allocator	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Operating Revenues					-	-	-	-	-	-	-	-	-
F_REVNU	REV	DISTRIBUTION REVENUES		REV_DIST	1,004,890,414	722,241,788	7,972,439	78,763,076	129,185,676	38,982,979	1,980,048	1,306,593	24,457,815
F_REVNU	REV	STATE TAX ADJ SURCHARGE		REV_STAS	-	-	-	-	-	-	-	-	-
F_REVNU	REV	LATE PAYMENT CHARGES		LT_FEES	15,305,520	11,428,698	83,895	1,363,531	1,785,597	542,576	81,961	19,262	-
F_REVNU	REV	ANNUALIZATION		REV_ANNL	4,932,874	3,865,736	(91,936)	20,269	891,225	221,023	8,188	(5,140)	23,509
F_REVNU	REV	MISCELLANEOUS SERVICE REVS		REV_TOTDPLT	969,910	650,351	9,996	77,482	145,439	55,636	896	1,377	28,732
F_REVNU	REV	RENT-ELECTRIC PROPERTY - DIST		REV_TOTDPLT	40,829,268	27,377,152	420,791	3,261,693	6,122,392	2,342,040	37,718	57,984	1,209,499
F_REVNU	REV	OTHER ELECTRIC REVENUE - DIST		REV_TOTDPLT	3,024,960	2,028,319	31,176	241,652	453,596	173,517	2,794	4,296	89,609
F_REVNU	REV	RESALE & BL REVENUES		REV_DIST	318,877	229,185	2,530	24,994	40,994	12,370	628	415	7,761
REV	BL REVENUES			REV_DIST	348,811	250,700	2,767	27,340	44,842	13,532	687	454	8,490
REV	LATE PAYMENT CHARGES INCREASE			LT_FEES	1,699,050	1,268,688	9,313	151,364	198,217	60,231	9,098	2,138	-
Total					1,072,319,685	769,340,619	8,440,970	83,931,401	138,867,977	42,403,904	2,122,019	1,387,379	25,825,415
					END								

Allocated Cost of Service Study

External Allocation Factors

Allocated Cost of Service Study					5	6	7	8	9	10	11	12
External Allocation Factors						Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
Name	No.	Description		Total	Residential RS							
DEMAND ALLOCATORS												
PRI_DEM	1	Demand at Primary	DEM	100.00%	54.09%	1.31%	5.64%	23.93%	14.62%	0.00%	0.17%	0.24%
		7,297,925		3,947,776	95,710	411,368	1,746,651	1,067,014	0	12,068	17,337	
		FPFTY		7,297,925	3,947,776	95,710	411,368	1,746,651	1,067,014	-	12,068	17,337
SEC_DEM	2	Demand at Secondary	DEM	100.00%	63.36%	1.54%	6.60%	28.03%	0.00%	0.00%	0.19%	0.28%
		6,076,221		3,849,767	93,334	401,156	1,703,288	0	0	11,769	16,906	
		FPFTY		6,076,221	3,849,767	93,334	401,156	1,703,288	-	-	11,769	16,906
SRV_DEM	3	Demand at Secondary for Services	DEM	100.00%	63.53%	1.54%	6.62%	28.11%	0.00%	0.00%	0.19%	0.00%
		6,059,314		3,849,767	93,334	401,156	1,703,288	0	0	11,769	0	
		FPFTY		6,059,314	3,849,767	93,334	401,156	1,703,288	-	-	11,769	-
BILL_KW	4	Billing Demand	DEM	100.00%	0.00%	0.00%	18.66%	51.49%	29.23%	0.14%	0.47%	0.00%
		48,977,538		0	0	9,138,797	25,219,929	14,316,117	70,926	231,768	0	
		FPFTY		48,977,538	-	-	9,138,797	25,219,929	14,316,117	70,926	231,768	-
CUSTOMER ALLOCATORS												
CUST	5	Total Customers	CUS	100.00%	86.47%	0.77%	9.80%	2.65%	0.08%	0.01%	0.10%	0.12%
		1,503,765		1,300,277	11,564	147,424	39,839	1,237	166	1,477	1,781	
		FPFTY		1,503,765	1,300,277	11,564	147,424	39,839	1,237	166	1,477	1,781
PRI_CUST	6	Primary Customers	CUS	100.00%	86.48%	0.77%	9.80%	2.65%	0.08%	0.00%	0.10%	0.12%
		1,503,599		1,300,277	11,564	147,424	39,839	1,237	0	1,477	1,781	
		FPFTY		1,503,599	1,300,277	11,564	147,424	39,839	1,237	-	1,477	1,781
SEC_CUST	7	Secondary Customers	CUS	100.00%	86.55%	0.77%	9.81%	2.65%	0.00%	0.00%	0.10%	0.12%
		1,502,362		1,300,277	11,564	147,424	39,839	0	0	1,477	1,781	
		FPFTY		1,502,362	1,300,277	11,564	147,424	39,839	-	-	1,477	1,781
METERS	8	Meter Investment	CUS	100.00%	63.06%	0.63%	11.45%	17.53%	4.75%	2.32%	0.25%	0.00%
		2,061,903		1,300,277	12,955	236,184	361,520	97,882	47,921	5,164	0	
		FPFTY		2,061,903	1,300,277	12,955	236,184	361,520	97,882	47,921	5,164	-
SERV	9	Services	CUS	100.00%	75.56%	0.67%	13.53%	10.10%	0.00%	0.00%	0.14%	0.00%
		1,720,793		1,300,277	11,564	232,748	173,872	0	0	2,332	0	
		FPFTY		1,720,793	1,300,277	11,564	232,748	173,872	-	-	2,332	-
GRSWRTOFF	10	Uncollectible Accounts	CUS	100.00%	91.04%	0.31%	3.75%	4.21%	0.65%	0.03%	0.02%	0.00%
		33,659,175		30,642,166	103,951	1,261,953	1,415,506	219,686	8,976	6,937	0	
		FPFTY		33,659,175	30,642,166	103,951	1,261,953	1,415,506	219,686	8,976	6,937	-
DEPOSIT	11	Customer Deposits	CUS	100.00%	30.20%	0.19%	23.38%	43.62%	1.67%	0.00%	0.22%	0.72%
		5,933,674		1,792,042	11,255	1,387,352	2,588,203	98,939	0	13,142	42,741	
		FPFTY		5,933,674	1,792,042	11,255	1,387,352	2,588,203	98,939	-	13,142	42,741
MTREAD	12	Meter Reading	CUS	100.00%	86.57%	0.77%	9.82%	2.65%	0.08%	0.01%	0.10%	0.00%
		1,300,277		11,564	147,424	39,839	1,237	166	1,477	0		
		FPFTY		1,501,984	1,300,277	11,564	147,424	39,839	1,237	166	1,477	-
AREALGT	12	Area Light	CUS	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

Allocated Cost of Service Study

External Allocation Factors

Allocated Cost of Service Study					5	6	7	8	9	10	11	12
External Allocation Factors												
Name	No.	Description		Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
		FPFTY		1	0	0	0	0	0	0	0	1
				1	-	-	-	-	-	-	-	1
STTRLGT	13	Street Light	CUS	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
		FPFTY		1	0	0	0	0	0	0	0	1
				1	-	-	-	-	-	-	-	1
CC_BILDET	14	Customer Charge Billing Determinants	CUS	100.00%	86.47%	0.77%	9.80%	2.65%	0.08%	0.01%	0.10%	0.12%
				18,045,181	15,603,324	138,767	1,769,083	478,071	14,840	1,993	17,726	21,377
		FPFTY		18,045,181	15,603,324	138,767	1,769,083	478,071	14,840	1,993	17,726	21,377

REVENUE ALLOCATORS

REV_DIST	15	DISTRIBUTION REVENUES	REV	100.00%	71.87%	0.79%	7.84%	12.86%	3.88%	0.20%	0.13%	2.43%
				1,004,890,414	722,241,788	7,972,439	78,763,076	129,185,676	38,982,979	1,980,048	1,306,593	24,457,815
		FPFTY		1,004,890,414	722,241,788	7,972,439	78,763,076	129,185,676	38,982,979	1,980,048	1,306,593	24,457,815
REV_STAS	16	STATE TAX ADJ SURCHARGE	REV	100.00%	73.20%	0.89%	6.94%	12.03%	4.05%	0.84%	0.11%	1.94%
				(4,717,995)	-3,453,606	-41,958	-327,401	-567,361	-190,981	-39,687	-5,416	-91,585
		FPFTY		(4,717,995)	(3,453,606)	(41,958)	(327,401)	(567,361)	(190,981)	(39,687)	(5,416)	(91,585)
LT_FEES	16	LATE PAYMENTS	REV	100.00%	74.67%	0.55%	8.91%	11.67%	3.54%	0.54%	0.13%	0.00%
				15,294,546	11,420,504	83,834	1,362,554	1,784,316	542,187	81,903	19,248	0
		FPFTY		15,294,546	11,420,504	83,834	1,362,554	1,784,316	542,187	81,903	19,248	-
REV_ANNL	17	Annualization Adjustments to Revenue	REV	100.00%	78.37%	-1.86%	0.41%	18.07%	4.48%	0.17%	-0.10%	0.48%
				4,929,729	3,863,271	-91,877	20,256	890,656	220,882	8,182	-5,137	23,494
		FPFTY		4,929,729	3,863,271	(91,877)	20,256	890,656	220,882	8,182	(5,137)	23,494
REV_TOTDPLT	17	Distribution Plant in Service - Revenue	REV	100.00%	67.05%	1.03%	7.99%	15.00%	5.74%	0.09%	0.14%	2.96%
				9,139,764,425	6,128,464,497	94,195,400	730,140,527	1,370,517,268	524,273,284	8,443,272	12,979,970	270,750,207
		FPFTY		9,139,764,425	6,128,464,497	94,195,400	730,140,527	1,370,517,268	524,273,284	8,443,272	12,979,970	270,750,207

FUEL ALLOCATORS

FUL_ENRGYSF	18	MWH SALES	FUL	100.00%	33.83%	0.55%	4.40%	19.60%	14.00%	27.36%	0.08%	0.17%
				45,406,935	15,359,919	249,522	1,998,926	8,900,397	6,355,685	12,425,021	38,132	79,334
		FPFTY		45,406,935	15,359,919	249,522	1,998,926	8,900,397	6,355,685	12,425,021	38,132	79,334

OTHER ALLOCATORS

ROR	19	Rate of Return	OTHER		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
		FPFTY	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	
				8.56%	8.56%	8.56%	8.56%	8.56%	8.56%	8.56%		
ROD	20	Cost of Debt	OTHER		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
		FPFTY	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	
				2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%		
ROE	21	Cost of Equity	OTHER		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
		FPFTY	6.33%	6.33%	6.33%	6.33%	6.33%	6.33%	6.33%	6.33%	6.33%	
				6.33%	6.33%	6.33%	6.33%	6.33%	6.33%	6.33%		

Allocated Cost of Service Study
Internal Allocation Factors

			7	15	23	31	39	47	55	63	
Internal Allocation Factors			L	T	AB	AJ	AR	AZ	BH	BP	
Internal Allocators											
	Allocator Name	Description	Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
TRUE	DPLT	Distribution Plant less Internals	9,026,271,329	6,052,364,241	93,025,728	721,074,001	1,353,498,860	517,763,117	8,338,428	12,818,791	267,388,164
			100.00%	67.05%	1.03%	7.99%	15.00%	5.74%	0.09%	0.14%	2.96%
TRUE	PLT_360	Acct 360 Distribution Plant	113,493,096	76,100,256	1,169,672	9,066,526	17,018,409	6,510,168	104,844	161,179	3,362,043
			100.00%	67.05%	1.03%	7.99%	15.00%	5.74%	0.09%	0.14%	2.96%
TRUE	PLT_362	Acct 362 Distribution Plant	1,557,785,071	955,208,683	18,376,977	103,871,738	297,834,890	170,100,138	410,309	2,357,560	9,624,776
			100.00%	61.32%	1.18%	6.67%	19.12%	10.92%	0.03%	0.15%	0.62%
TRUE	PLT_364	Acct 364 Distribution Plant	1,882,353,189	1,430,023,385	18,166,417	158,877,084	189,979,270	79,347,378	-	2,306,392	3,653,263
			100.00%	75.97%	0.97%	8.44%	10.09%	4.22%	0.00%	0.12%	0.19%
TRUE	PLT_365	Acct 365 Distribution Plant	1,947,235,550	1,335,380,337	22,473,713	145,068,723	325,207,640	112,346,431	-	2,843,218	3,915,489
			100.00%	68.58%	1.15%	7.45%	16.70%	5.77%	0.00%	0.15%	0.20%
TRUE	PLT_366	Acct 366 Distribution Plant	377,893,800	244,702,097	4,326,747	26,458,493	65,187,246	35,913,571	-	547,104	758,543
			100.00%	64.75%	1.14%	7.00%	17.25%	9.50%	0.00%	0.14%	0.20%
TRUE	PLT_367	Acct 367 Distribution Plant	994,823,277	644,189,827	11,390,365	69,653,233	171,608,503	94,544,171	-	1,440,276	1,996,901
			100.00%	64.75%	1.14%	7.00%	17.25%	9.50%	0.00%	0.14%	0.20%
TRUE	PLT_360_2	Acct 360 thru 362 Distribution Plant	1,735,006,103	1,065,782,242	20,382,424	116,530,470	330,105,645	185,927,833	515,154	2,624,124	13,138,211
			100.00%	61.43%	1.17%	6.72%	19.03%	10.72%	0.03%	0.15%	0.76%
TRUE	PLT_360_1	Acct 360 & 361 Distribution Plant	177,221,031	110,573,559	2,005,447	12,658,732	32,270,755	15,827,695	104,844	266,564	3,513,434
			100.00%	62.39%	1.13%	7.14%	18.21%	8.93%	0.06%	0.15%	1.98%
TRUE	PLT_364_5	Acct 364 & 365 Distribution Plant	3,829,588,738	2,765,403,721	40,640,130	303,945,807	515,186,910	191,693,809	-	5,149,610	7,568,752
			100.00%	72.21%	1.06%	7.94%	13.45%	5.01%	0.00%	0.13%	0.20%
TRUE	PLT_366_7	Acct 366 & 367 Distribution Plant	1,372,717,077	888,891,924	15,717,112	96,111,727	236,795,748	130,457,742	-	1,987,379	2,755,444
			100.00%	64.75%	1.14%	7.00%	17.25%	9.50%	0.00%	0.14%	0.20%
TRUE	PLT_369	Acct 369 Distribution Plant	846,971,069	639,993,827	5,691,752	114,558,037	85,579,599	-	-	1,147,854	-
			100.00%	75.56%	0.67%	13.53%	10.10%	0.00%	0.00%	0.14%	0.00%
TRUE	TOTDPLT	Distribution Plant	9,139,764,425	6,128,464,497	94,195,400	730,140,527	1,370,517,268	524,273,284	8,443,272	12,979,970	270,750,207
			100.00%	67.05%	1.03%	7.99%	15.00%	5.74%	0.09%	0.14%	2.96%
TRUE	DEPR	Total Depreciation Expense	324,155,908	229,966,874	3,093,648	27,482,008	40,502,945	13,580,987	719,042	451,693	8,358,711
			100.00%	70.94%	0.95%	8.48%	12.49%	4.19%	0.22%	0.14%	2.58%
TRUE	DEPR_DPLT	Distribution Depreciation Expense	264,935,209	184,213,819	2,567,243	22,185,791	35,471,726	11,951,338	669,025	380,399	7,495,868
			100.00%	69.53%	0.97%	8.37%	13.39%	4.51%	0.25%	0.14%	2.83%
TRUE	DEPR_GIPLT	General and Intangible Depreciation Expense	59,220,699	45,753,055	526,405	5,296,217	5,031,219	1,629,649	50,017	71,295	862,843
			100.00%	77.26%	0.89%	8.94%	8.50%	2.75%	0.08%	0.12%	1.46%
TRUE	DISTOPLBR	Distribution Operations Labor Excludes Supervision	18,574,359	13,036,713	184,376	1,604,405	2,628,693	948,026	43,628	27,430	101,089
			100.00%	70.19%	0.99%	8.64%	14.15%	5.10%	0.23%	0.15%	0.54%

Allocated Cost of Service Study
Internal Allocation Factors

Allocated Cost of Service Study			7	15	23	31	39	47	55	63	
Internal Allocation Factors			L	T	AB	AJ	AR	AZ	BH	BP	
Internal Allocators											
	Allocator Name	Description	Total	RS	RTS	GS-1	GS-3	LP-4	LP-5	GH-2	SL/AL
TRUE	DMAINTLBR	Distribution Maintenance Labor	11,964,895	7,960,023	120,568	875,074	1,584,226	637,212	478	15,320	771,994
			100.00%	66.53%	1.01%	7.31%	13.24%	5.33%	0.00%	0.13%	6.45%
TRUE	CUSTACCTLBR	Customer Accounts Exluding Uncollectibles and Services	16,551,405	14,312,920	127,291	1,622,779	438,534	13,612	1,828	16,260	18,180
			100.00%	86.48%	0.77%	9.80%	2.65%	0.08%	0.01%	0.10%	0.11%
TRUE	LABOR	Labor Expense (excluding A&G labor)	63,202,778	48,829,551	561,801	5,652,342	5,369,525	1,739,228	53,381	76,089	920,862
			100.00%	77.26%	0.89%	8.94%	8.50%	2.75%	0.08%	0.12%	1.46%
TRUE	NETTOTPLT	Net Total Plant in Service	6,945,907,524	4,705,984,220	72,380,845	545,419,109	1,022,789,878	403,661,354	4,166,399	9,692,887	181,812,833
			100.00%	67.75%	1.04%	7.85%	14.73%	5.81%	0.06%	0.14%	2.62%
TRUE	TOTPLT	Total Plant in Service	10,201,986,912	6,949,122,208	103,637,354	825,137,052	1,460,760,608	553,503,765	9,340,417	14,258,762	286,226,745
			100.00%	68.12%	1.02%	8.09%	14.32%	5.43%	0.09%	0.14%	2.81%
TRUE	RTBASE	Rate Base	5,820,789,148	3,945,884,998	60,953,083	453,785,827	857,366,617	341,754,581	3,137,688	8,107,041	149,799,315
			100.00%	67.79%	1.05%	7.80%	14.73%	5.87%	0.05%	0.14%	2.57%
TRUE	OMEXCLUNCOL	O&M Expense Excluding Uncollectible	399,064,157	297,123,043	3,726,921	35,592,850	41,891,630	14,201,969	230,328	508,795	5,788,621
			100.00%	74.45%	0.93%	8.92%	10.50%	3.56%	0.06%	0.13%	1.45%
TRUE	DEFRTX	Deferred Income Tax	46,470,000	33,528,527	446,026	3,933,897	5,459,496	1,972,833	41,090	60,974	1,027,156
			100.00%	72.15%	0.96%	8.47%	11.75%	4.25%	0.09%	0.13%	2.21%
TRUE	904INCREASE	Uncollectible Increase	6,421,504	5,845,919	19,832	240,756	270,051	41,912	1,712	1,323	-
			100.00%	91.04%	0.31%	3.75%	4.21%	0.65%	0.03%	0.02%	0.00%
TRUE	GRTINCREASE	GRT Increase	22,406,453	15,262,241	227,617	1,812,235	3,208,244	1,215,651	20,514	31,316	628,635
			100.00%	68.12%	1.02%	8.09%	14.32%	5.43%	0.09%	0.14%	2.81%
TRUE	GRT	GRT @ Present Revenues	56,151,000	38,247,467	570,413	4,541,495	8,039,921	3,046,445	51,409	78,479	1,575,371
			100.00%	68.12%	1.02%	8.09%	14.32%	5.43%	0.09%	0.14%	2.81%
TRUE	ITC	Investment Tax Credit	(15,000)	(10,058)	(155)	(1,198)	(2,249)	(860)	(14)	(21)	(444)
			100.00%	67.05%	1.03%	7.99%	15.00%	5.74%	0.09%	0.14%	2.96%
TRUE	FTC	FEDERAL Tax Credit	(900,000)	(603,475)	(9,275)	(71,898)	(134,956)	(51,626)	(831)	(1,278)	(26,661)
			100.00%	67.05%	1.03%	7.99%	15.00%	5.74%	0.09%	0.14%	2.96%
TRUE	PUC	PUC FEE INCRAESE	1,110,654	752,489	11,574	87,213	163,545	64,546	666	1,550	29,072
			100.00%	67.75%	1.04%	7.85%	14.73%	5.81%	0.06%	0.14%	2.62%

**PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-1R
FULLY PROJECTED FUTURE TEST YEAR ENDED JUNE 30, 2027**

**SECTION V
JURISDICTIONAL – FUNCTIONALIZATION, CLASSIFICATION, AND ALLOCATION**

This section shows the functionalization, classification, and allocation factors for each FERC account that ultimately constitutes the total revenue requirements. The second part of this section, after this description, provides details on the functionalization and classification of each account. In this part each account of the revenue requirement and the amount of dollars therein, is shown in the first column of costs. The other columns show the assignment of function, classification, and allocation factors to each cost item.

Once the costs are functionalized and classified they are then allocated to FERC jurisdictional services and customers and PUC Jurisdictional retail customers. This is shown in the fourth part of this section and is broken into categories, such as rate base, depreciation, O&M expense, and taxes.

Lastly, a summary of the jurisdictional allocation factors, both external and internal, that are utilized to allocate the functions to rate classes is provided.

The primary secondary allocations and minimum system study that support the results presented in this section are provided in Exhibit BR-2.

Jurisdictional Cost of Service Study

Cost Assignment Matrix

Acct. No.	Account Description	Fully Projected Future Year 2024	Fully Projected Future Year 2025	Fully Projected Future Year 2026	Function	Classifier	DEM	CUS	GNR	REV	FUL	Internal
RATE BASE												
Plant-in Service												
Intangible Plant												
301-303	INTANGIBLE PLANT - DISTRIBUTION	670,295		670,295								LABOR_NOTRNL
301-303	INTANGIBLE PLANT - TRANSMISSION	-		-	F_TRANS	GNR			GNR_TRANS			
	Sub-total	670,295		670,295								
Transmission Plant												
350-359	TRANSMISSION PLANT	10,162,924,834		10,162,924,834	F_TRANS	GNR			GNR_TRANS			
	Sub-total	10,162,924,834		10,162,924,834								
Distribution Plant												
360	LAND AND LAND RIGHTS	113,493,096		113,493,096	F_DSTPR	DEM	PRI_DEM					DPLT
361	STRUCTURES & IMPROVEMENTS	63,727,935		63,727,935	F_DSTPR	DEM	PRI_DEM					
362	STATION EQUIPMENT - PRIMARY	1,071,977,540		1,071,977,540								LABOR_NOTRNL
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNI	485,807,532		485,807,532	F_DSTPR	PRI_POLES	PRI_DEM	PRI_CUST				
364	POLES TOWERS & FIXTURES - PRIMARY	1,378,363,819		1,378,363,819	F_DSTSC	SEC_POLES	SEC_DEM	SEC_CUST				
364	POLES TOWERS & FIXTURES - SECONDARY	503,367,775		503,367,775	F_DSTPR	PRI_OH	PRI_DEM	PRI_CUST				
365	OVERHEAD CONDUCTORS - PRIMARY	1,393,796,201		1,393,796,201	F_DSTSC	SEC_OH	SEC_DEM	SEC_CUST				
365	OVERHEAD CONDUCTORS - SECONDARY	553,439,348		553,439,348	F_DSTPR	PRI_UG	PRI_DEM	PRI_CUST				
366	UNDERGROUND CONDUIT - PRIMARY	361,329,048		361,329,048	F_DSTSC	SEC_UG	SEC_DEM	SEC_CUST				
366	UNDERGROUND CONDUIT - SECONDARY	16,564,752		16,564,752	F_DSTPR	PRI_UG	PRI_DEM	PRI_CUST				
367	UNDERGROUND CONDUCTORS - PRIMARY	951,215,784		951,215,784	F_DSTSC	SEC_UG	SEC_DEM	SEC_CUST				
367	UNDERGROUND CONDUCTORS - SECONDARY	43,607,493		43,607,493	F_TRANF	SEC_TRANS	SEC_DEM	SEC_CUST				DPLT
368	LINE TRANSFORMERS	768,750,265		768,750,265	F_SERVS	CUS		SEC_CUST				
369	SERVICES	846,971,069		846,971,069	F_METER	CUS		DIST				
370	METERS	341,126,522		341,126,522	F_LIGHT	CUS		DIST				
371	INSTALLATIONS ON CUST PREMISES	15,029,035		15,029,035	F_LIGHT	CUS		DIST				
373	STREET LIGHTING & SIGNAL SYSTEMS	230,575,615		230,575,615								
387	ENERGY STORAGE EQUIPMENT	621,595		621,595								
	Sub-total	9,139,764,425		9,139,764,425								
General Plant												
389-399	GENERAL PLANT - DISTRIBUTION	1,061,552,192		1,061,552,192								LABOR_NOTRNL
389-399	GENERAL PLANT - TRANSMISSION	7,755,200		7,755,200	F_TRANS	GNR			GNR_TRANS			
	Sub-total	1,069,307,392		1,069,307,392								
	TOTAL PLANT-IN-SERVICE	20,372,666,945		20,372,666,945								
Accumulated Reserve for Depreciation												
Intangible Plant												
301-303	INTANGIBLE PLANT - DISTRIBUTION	-		-								LABOR_NOTRNL
301-303	INTANGIBLE PLANT - TRANSMISSION	-		-	F_TRANS	GNR			GNR_TRANS			
	Sub-total	-		-								
Transmission Plant												
350-359	TRANSMISSION PLANT	1,484,404,073		1,484,404,073	F_TRANS	GNR			GNR_TRANS			
	Sub-total	1,484,404,073		1,484,404,073								
Distribution Plant												
360	LAND AND LAND RIGHTS	41,596,195		41,596,195	F_DSTPR	DEM	PRI_DEM					PLT_360
361	STRUCTURES & IMPROVEMENTS	21,397,940		21,397,940	F_DSTPR	DEM	PRI_DEM					
362	STATION EQUIPMENT - PRIMARY	234,310,665		234,310,665								LABOR_NOTRNL
363	COMPUTER SOFTWARE & HARDWARE AND COMMUNI	136,518,580		136,518,580	F_DSTPR	PRI_POLES	PRI_DEM	PRI_CUST				
364	POLES TOWERS & FIXTURES - PRIMARY	399,016,926		399,016,926	F_DSTSC	SEC_POLES	SEC_DEM	SEC_CUST				
364	POLES TOWERS & FIXTURES - SECONDARY	145,717,886		145,717,886	F_DSTPR	PRI_OH	PRI_DEM	PRI_CUST				
365	OVERHEAD CONDUCTORS - PRIMARY	282,476,603		282,476,603	F_DSTSC	SEC_OH	SEC_DEM	SEC_CUST				
365	OVERHEAD CONDUCTORS - SECONDARY	112,163,935		112,163,935	F_DSTPR	PRI_UG	PRI_DEM	PRI_CUST				
366	UNDERGROUND CONDUIT - PRIMARY	88,182,404		88,182,404	F_DSTSC	SEC_UG	SEC_DEM	SEC_CUST				
366	UNDERGROUND CONDUIT - SECONDARY	4,042,630		4,042,630	F_DSTPR	PRI_UG	PRI_DEM	PRI_CUST				
367	UNDERGROUND CONDUCTORS - PRIMARY	285,835,286		285,835,286	F_DSTSC	SEC_UG	SEC_DEM	SEC_CUST				
367	UNDERGROUND CONDUCTORS - SECONDARY	13,103,820		13,103,820	F_TRANF	SEC_TRANS	SEC_DEM	SEC_CUST				
368	LINE TRANSFORMERS	264,153,503		264,153,503	F_SERVS	CUS		SEC_CUST				
369	SERVICES	430,314,690		430,314,690	F_METER	CUS		DIST				
370	METERS	197,489,696		197,489,696	F_LIGHT	CUS		DIST				
371	INSTALLATIONS ON CUST PREMISES	8,531,974		8,531,974	F_LIGHT	CUS		DIST				
373	STREET LIGHTING & SIGNAL SYSTEMS	81,290,032		81,290,032								
387	ENERGY STORAGE EQUIPMENT	303,119		303,119								DPLT
	Sub-total	2,746,445,884		2,746,445,884								

Jurisdictional Cost of Service Study
Cost Assignment Matrix

Acct. No.	Account Description	Fully Projected Future Test Year		Fully Projected Future Test Year	Function	Classifier	DEM	CUS	GNR	REV	FUL	Internal
General Plant												
389-399	GENERAL PLANT - DISTRIBUTION	509,633,503			509,633,503							LABOR_NOTRN
389-399	GENERAL PLANT - TRANSMISSION	3,219,909			3,219,909	F_TRANS	GNR		GNR_TRANS			
Sub-total		512,853,412			512,853,412							
TOTAL DEPRECIATION ACCRUAL		4,743,703,369			4,743,703,369							
NET PLANT		15,628,963,576			15,628,963,576							
Rate Base Adjustments												
Additions												
RB ADJ	PLANT HELD FOR FUTURE USE - TRANSMISSION	-			-	F_TRANS	GNR		GNR_TRANS			
RB ADJ	PLANT HELD FOR FUTURE USE - DISTRIBUTION	-			-	F_DISTR	DEM	PRI_DEM				
RB ADJ	PLANT HELD FOR FUTURE USE - GENERAL	-			-							LABOR_NOTRN
RB ADJ	CASH WORKING CAPITAL - O&M	6,785,648			6,785,648	F_CWRKC	GNR		OM_CWC			
RB ADJ	CASH WORKING CAPITAL - ACCRUED TAXES	14,309,000			14,309,000	F_CWRKC	GNR		TAX_CWC			
RB ADJ	CASH WORKING CAPITAL - INTEREST PAYMENT	(33,802,525)			(33,802,525)	F_CWRKC	GNR		INTRST_CWC			
RB ADJ	CASH WORKING CAPITAL - PREPAYMENTS - TRANSMISSION	7,163,535			7,163,535	F_TRANS	GNR		GNR_TRANS			
RB ADJ	CASH WORKING CAPITAL - PREPAYMENTS - DISTRIBUTION	6,257,237			6,257,237							TOTDPLT
RB ADJ	MATERIALS AND SUPPLIES - TRANSMISSION	37,144,032			37,144,032	F_TRANS	GNR		GNR_TRANS			
RB ADJ	MATERIALS AND SUPPLIES - DISTRIBUTION	72,145,527			72,145,527							TOTDPLT
Sub-total		110,002,454			110,002,454							
Deductions												
RB ADJ	CIAC - TRANSMISSION	19,034,000			19,034,000	F_TRANS	GNR		GNR_TRANS			
RB ADJ	CIAC - DISTRIBUTION	155,133,000			155,133,000	F_DISTR	GNR		GNR_DIST			
RB ADJ	CIAC - GENERAL	213,000			213,000							LABOR_NOTRN
RB ADJ	ARCS AND MARCS - TRANSMISSION	(1,421,001,000)			(1,421,001,000)	F_TRANS	GNR		GNR_TRANS			
RB ADJ	ARCS AND MARCS - DISTRIBUTION	(778,767,000)			(778,767,000)							TOTDPLT
RB ADJ	ARCS AND MARCS - GENERAL	(96,296,000)			(96,296,000)							LABOR_NOTRN
RB ADJ	OTHER 263A REPAIR ALLOWANCES - TRANSMISSION	(12,609,000)			(12,609,000)							
RB ADJ	OTHER 263A REPAIR ALLOWANCES - DISTRIBUTION	(500,288,000)			(500,288,000)	F_TRANS	GNR		GNR_TRANS			TOTDPLT
RB ADJ	OTHER 263A REPAIR ALLOWANCES - GENERAL	12,833,000			12,833,000							LABOR_NOTRN
RB ADJ	CUSTOMER ADVANCES	-			-	F_DISTR	GNR		GNR_DIST			
RB ADJ	CUSTOMER DEPOSITS	(6,554,000)			(6,554,000)	F_DISTR	CUS	DEPOSIT				
Sub-total		(2,628,302,000)			(2,628,302,000)							
TOTAL RATE BASE ADJ.		(2,518,299,546)			(2,518,299,546)							
TOTAL RATE BASE		13,110,664,031			13,110,664,031							

**Jurisdictional Cost of Service Study
Cost Assignment Matrix**

Acct. No.	Account Description	Fully Projected Future Test Year			Fully Projected Future Test Year	Function	Classifier	DEM	CUS	GNR	REV	FUL	Internal
Administrative and General Expenses													
920-923	A&G SALARIES & OFFICE SUPPLIES - DIST	86,305,572			86,305,572								LABOR_NOTRNR
924	PROPERTY INSURANCE - DIST	2,058,405			2,058,405								DPLT
925	INJURIES & DAMAGES - DIST	6,965,752			6,965,752								LABOR_NOTRNR
926	EMPLOYEE BENEFITS - DIST	2,395,082			2,395,082								LABOR_NOTRNR
927	FRANCHISE REQUIREMENTS - DIST	-			-	F_CUSSV	CUS		DIST				
928P	REGULATORY COMMISSION EXPENSE - PPUC - DIST	6,663,737			6,663,737	F_CUSSV	CUS		DIST				
928F	REGULATORY COMMISSION EXPENSE - FERC - DIST	-			-	F_TRANS	CUS		TRANS				
930	GENERAL ADVERTISING EXPENSE - DIST	(12,885,859)			(12,885,859)								DPLT
931	RENT/FACILITIES - DIST	916,027			916,027								DPLT
935	MAINTENANCE OF GENERAL PLANT - DIST	38,427,748			38,427,748								LABOR_NOTRNR
920-923	A&G SALARIES & OFFICE SUPPLIES - TRAN	26,118,535			26,118,535	F_TRANS	CUS		TRANS				
924	PROPERTY INSURANCE - TRAN	1,896,754			1,896,754	F_TRANS	CUS		TRANS				
925	INJURIES & DAMAGES - TRAN	1,582,030			1,582,030	F_TRANS	CUS		TRANS				
926	EMPLOYEE BENEFITS - TRAN	610,404			610,404	F_TRANS	CUS		TRANS				
927	FRANCHISE REQUIREMENTS - TRAN	-			-	F_TRANS	CUS		TRANS				
928P	REGULATORY COMMISSION EXPENSE - PPUC - TRAN	-			-	F_TRANS	CUS		TRANS				
928F	REGULATORY COMMISSION EXPENSE - FERC - TRAN	-			-	F_TRANS	CUS		TRANS				
930	GENERAL ADVERTISING EXPENSE - TRAN	1,152,787			1,152,787	F_TRANS	CUS		TRANS				
931	RENT/FACILITIES - TRANS	249,285			249,285	F_TRANS	CUS		TRANS				
935	MAINTENANCE OF GENERAL PLANT - TRAN	6,506,316			6,506,316	F_TRANS	CUS		TRANS				
928	PUC FEE INCREASE	1,110,654			1,110,654	F_CUSSV	CUS		DIST				
Sub-total		170,073,229			170,073,229								
TOTAL O & M EXPENSES		511,573,005			511,573,005								
Labor Expense													
Transmission Operation Expenses													
560-567	TRANSMISSION OPERATION EXPENSES	2,746,006			2,746,006	F_TRANS	GNR			GNR_TRANS			
Sub-total		2,746,006			2,746,006								
Transmission Maintenance Expenses													
568-576	TRANSMISSION MAINTENANCE EXPENSES	3,452,973			3,452,973	F_TRANS	GNR			GNR_TRANS			
Sub-total		3,452,973			3,452,973								
Total Transmission		6,198,979			6,198,979								
Distribution Operation Expenses													
580	SUPERVISION AND ENGINEERING	2,531,568			2,531,568								DISTOPLBR
581	LOAD DISPATCHING	205,354			205,354								PLT_360_2
582	STATION EXPENSES	63,106			63,106								PLT_360_2
583	OVERHEAD LINES	11,129,059			11,129,059								PLT_364_5
584	UNDERGROUND LINES	1,412,410			1,412,410								PLT_366_7
585	STREET LIGHTING & SIGNAL SYSTEMS	-			-	F_LIGHT	CUS		DIST				
586	METER EXPENSE	1,774,160			1,774,160								PLT_370
587	CUSTOMER INSTALLATION EXPENSE	1,484,627			1,484,627	F_SERVS	CUS		DIST				
588	MISC. DISTRIBUTION EXPENSE	2,505,643			2,505,643								DPLT
589	RENTS	-			-								DPLT
577-578	ENERGY STORAGE O&M	-			-								DPLT
Sub-total		21,105,928			21,105,928								
Distribution Maintenance Expenses													
590	SUPERVISION AND ENGINEERING	-			-								DMAINTLBR
591	STRUCTURES	-			-								PLT_360_2
592	STATION EQUIPMENT	1,261,242			1,261,242								PLT_360_2
593	OVERHEAD LINES	9,796,738			9,796,738								PLT_364_5
593.5	OVERHEAD LINES - SERVICES	-			-	F_SERVS	SEC_SERVS	SEC_DEM	SEC_CUST				
594	UNDERGROUND LINES	55,053			55,053	F_SERVS	SEC_SERVS	SEC_DEM	SEC_CUST				PLT_366_7
594.3 & 594.6	UNDERGROUND LINES - SERVICES	-			-	F_TRANF	SEC_TRANS	SEC_DEM	SEC_CUST				
595	LINE TRANSFORMERS	-			-	F_LIGHT	CUS		DIST				
596	STREET LIGHT & SIGNAL SYSTEMS	739,646			739,646								
597	METERS	-			-								PLT_370
598	MISCELLANEOUS DISTRIB. PLANT	112,216			112,216								DPLT
Sub-total		11,964,895			11,964,895								
Total Distribution		33,070,822			33,070,822								
Customer Account													
901	SUPERVISION	3,084,792			3,084,792								CUSTACCTLBR
902	METER READING	-			-	F_CUSSV	CUS		CUST				
903CR	CUSTOMER RECORDS	15,198,749			15,198,749	F_CUSSV	CUS		CUST				
903CE	COLLECTION EXPENSES	-			-	F_CUSSV	CUS		DIST				
904 T	UNCOLLECTIBLE ACCOUNTS TRANSMISSION	-			-	F_CUSSV	CUS		TRANS				
904 D	PROPERTY DAMAGE DISTRIBUTION	-			-								DPLT
904 by RATE	UNCOLLECTIBLE ACCOUNTS	-			-	F_CUSSV	CUS		DIST				
905	MISC. CUSTOMER ACCOUNTS EXPENSES	147,080			147,080	F_CUSSV	CUS		CUST				
Sub-total		18,430,621			18,430,621								
Customer Service & Information Expenses													
908-OnTrack	ONTRACK ARREARAGE FORGIVENESS	-			-	F_CUSSV	CUS		DIST				
908 Other - 911	OTHER CUSTOMER SERVICE AND INFORMATION	10,495,759			10,495,759	F_CUSSV	CUS		DIST				
Sub-total		10,495,759			10,495,759								
Sales Expenses													
911-916	SALES EXPENSES	-			-	F_CUSSV	CUS		DIST				
920-935	A&G - TRANSMISSION	650,588			650,588	F_TRANS	CUS		TRANS				
920-935	A&G - DISTRIBUTION	12,941,259			12,941,259	F_CUSSV	CUS		DIST				
Sub-total		13,591,846			13,591,846								
TOTAL O & M LABOR EXP.		81,788,028			81,788,028								
Depreciation Expense													
Intangible Plant													
301-303	INTANGIBLE PLANT - DISTRIBUTION	-			-								LABOR_NOTRNR
301-303	INTANGIBLE PLANT - TRANSMISSION	-			-	F_TRANS	GNR			GNR_TRANS			
301-303	INTANGIBLE PLANT - PRO FORMA	-			-								LABOR
Sub-total		-			-								
Transmission Plant													
350-359	TRANSMISSION PLANT	224,744,340			224,744,340	F_TRANS	GNR			GNR_TRANS			
350-359	TRANSMISSION PLANT - PRO FORMA	-			-	F_TRANS	GNR			GNR_TRANS			
Sub-total		224,744,340			224,744,340								
Distribution Plant													
360	LAND AND LAND RIGHTS	756,214			756,214								PLT_360
361	STRUCTURES & IMPROVEMENTS	814,601			814,601								PLT_360_1
362	STATION EQUIPMENT	20,033,725			20,033,725								PLT_362
363	COMPUTER SOFTWARE & HARDWARE AND COMMUN	66,278,524			66,278,524								LABOR_NOTRNR
364	POLES TOWERS & FIXTURES	42,177,610			42,177,610								PLT_364
365	OVERHEAD CONDUCTORS	45,318,855			45,318,855								PLT_365
366	UNDERGROUND CONDUIT	5,484,850			5,484,850								PLT_366
367	UNDERGROUND CONDUCTORS	17,061,472			17,061,472								PLT_367
368	LINE TRANSFORMERS	23,171,156			23,171,156	F_TRANF	SEC_TRANS	SEC_DEM	SEC_CUST				
369	SERVICES	9,866,936			9,866,936	F_SERVS	CUS		SEC_CUST				
370	METERS	26,031,923			26,031,923								PLT_370
371	INSTALLATIONS ON CUST PREMISES	476,054			476,054	F_LIGHT	CUS		DIST				
373	STREET LIGHTING & SIGNAL SYSTEMS	5,594,971			5,594,971	F_LIGHT	CUS		DIST				

Jurisdictional Cost of Service Study
Cost Assignment Matrix

Acct. No.	Account Description	Fully Projected Future Test Year			Fully Projected Future Test Year	Function	Classifier	DEM	CUS	GNR	REV	FUL	Internal
387	ENERGY STORAGE EQUIPMENT	42,520			42,520								
360-373	DISTRIBUTION PLANT - PRO FORMA	1,826,000			1,826,000	F_DISTR	GNR			GNR_DIST			DPLT
	Sub-total	264,935,209			264,935,209								
General Plant													
389-399	GENERAL PLANT - DISTRIBUTION	59,220,699			59,220,699								
389-399	GENERAL PLANT - TRANSMISSION	500,938			500,938	F_TRANS	GNR			GNR_TRANS			LABOR_NOTRN
389-399	GENERAL PLANT - PRO FORMA	-			-								LABOR
	Sub-total	59,721,637			59,721,637								
	TOTAL DEPRECIATION EXPENSES	549,401,186			549,401,186								
Amortization													
Other													
AMORT	AMORTIZATION - 2005 ICE STORM DEFERRAL	-			-	F_DISTR	GNR			GNR_DIST			
AMORT	AMORTIZATION OF 2010 RATE CASE EXPENSE	-			-	F_DISTR	GNR			GNR_DIST			
AMORT	AMORTIZATION - 2011 STORM DEFERRAL	-			-	F_DISTR	GNR			GNR_DIST			
	Sub-total	-			-								
	TOTAL AMORTIZATION EXPENSES	-			-								
Taxes Other Than Income Taxes													
TAX	DEFERRED TAXES - DISTRIBUTION	(2,515,000)			(2,515,000)	F_DISTR	GNR			GNR_DIST			
TAX	DEFERRED TAXES - ELECTRIC PLANT	(102,000)			(102,000)	F_DISTR	GNR			GNR_DIST			
TAX	DEFERRED TAXES - DISTRIBUTION PLANT	25,863,000			25,863,000								DPLT
TAX	DEFERRED TAXES - GROSS REVENUE TAXES	-			-								TOTPLT
TAX	DEFERRED TAXES - LABOR	23,224,000			23,224,000								LABOR_NOTRN
TAX	DEFERRED TAXES - MATERIALS AND SUPPLIES	-			-								LABOR_NOTRN
TAX	DEFERRED TAXES - TRANSMISSION	90,066,000			90,066,000	F_TRANS	GNR			GNR_TRANS			
TAX	CAPITAL STOCK - TRANSMISSION	-			-								
TAX	PROPERTY TAX - TRANSMISSION	1,818,000			1,818,000	F_TRANS	GNR			GNR_TRANS			
TAX	PROPERTY TAX - DISTRIBUTION	2,460,000			2,460,000	F_DISTR	GNR			GNR_DIST			
TAX	PUBLIC UTILITY REALTY - TRANSMISSION	1,610,000			1,610,000	F_TRANS	GNR			GNR_TRANS			
TAX	PUBLIC UTILITY REALTY - DISTRIBUTION	1,500,000			1,500,000	F_DISTR	GNR			GNR_DIST			
TAX	INVESTMENT TAX CREDIT - TRANSMISSION	(16,000)			(16,000)	F_TRANS	GNR			GNR_TRANS			
TAX	INVESTMENT TAX CREDIT - DISTRIBUTION	(15,000)			(15,000)	F_DISTR	GNR			GNR_DIST			
TAX	OTHER TAXES - DISTRIBUTION	-			-	F_DISTR	GNR			GNR_DIST			
TAX	OTHER TAXES - ELECTRIC PLANT	-			-	F_DISTR	GNR			GNR_DIST			
TAX	OTHER TAXES - DISTRIBUTION PLANT	-			-								
TAX	OTHER TAXES - LABOR	4,862,000			4,862,000								DPLT
TAX	OTHER TAXES - TRANSMISSION	659,000			659,000	F_TRANS	GNR			GNR_TRANS			LABOR_NOTRN
TAX	GROSS RECEIPTS TAX	56,151,000			56,151,000	F_DISTR	GNR			GNR_DIST			
TAX	GROSS RECEIPTS TAX + COMMISSION FEES - INCREA	22,406,453			22,406,453	F_DISTR	GNR			GNR_DIST			
	Sub-total	227,971,453			227,971,453								
	TOTAL TAXES OTHER THAN INCOME TAX	227,971,453			227,971,453								

Jurisdictional Cost of Service Study

Cost Assignment Matrix

Cost Assignment Matrix				Fully Classified		Fully Projected		Fully Projected		Function	Classifier	DEM	CUS	GNR	REV	FUL	Internal
Acct. No.	Account Description	Future Test Year		Future Test Year													
Adjustments to Taxable Income																	
TAX	TAX ADJUSTMENT - TRANS RELATED	(317,092,000)			(317,092,000)	F TRANS	GNR							GNR_TRANS			
TAX	TAX ADJUSTMENT - PA JURISDICTION RELATED	(203,479,000)			(203,479,000)	F DISTR	GNR							GNR_DIST			
TAX	TAX ADJUSTMENT - DEPRECIATION RELATED	5,160,000			5,160,000	F DISTR	GNR							GNR_DIST			DEPR_DPLT
TAX	TAX ADJUSTMENT - DIST DEPRECIATION RELATED	43,234,000			43,234,000												DEPR_GIPLT
TAX	TAX ADJUSTMENT - G&I DEPRECIATION RELATED	(94,877,000)			(94,877,000)												DPLT
TAX	TAX ADJUSTMENT - DISTRIBUTION PLANT RELATED	-			-												
TAX	TAX ADJUSTMENT - ELECTRIC PLANT RELATED	376,000			376,000												
TAX	TAX ADJUSTMENT - GRT RELATED	-			-	F DISTR	GNR							GNR_DIST			LABOR_NOTRNL
TAX	TAX ADJUSTMENT - LABOR RELATED	15,252,000			15,252,000												LABOR
TAX	TAX ADJUSTMENT - M&S RELATED	-			-												
TAX	TAX ADJUSTMENT - PRO FORMA G&I DEPRECIATION R	-			-												
	Sub-total	(551,426,000)			(551,426,000)												
PA Special Deductions																	
TAX	PA SPECIAL DEDUCTIONS - TRANSMISSION RELATED	(90,437,000)			(90,437,000)	F_TRANS	GNR							GNR_TRANS			DEPR_DPLT
TAX	PA SPECIAL DEDUCTIONS - DIST DEPRECIATION RELAT	(33,338,000)			(33,338,000)												DPLT
TAX	PA SPECIAL DEDUCTIONS - ELECTRIC PLANT RELATED	(900,000)			(900,000)												DEPR_GIPLT
TAX	PA SPECIAL DEDUCTIONS - DISTRIBUTION PLANT RELA	-			-												TOTPLT
TAX	PA SPECIAL DEDUCTIONS - G&I DEPRECIATION RELATE	-			-												
TAX	PA SPECIAL DEDUCTIONS - FEDERAL NOL	-			-												
TAX	FEDEARL TAX CREDIT - TRANS	(500,000)			(500,000)	F_TRANS	GNR							GNR_TRANS			DPLT
TAX	FEDEARL TAX CREDIT - DIST	(900,000)			(900,000)												
	TOTAL	(126,075,000)			(126,075,000)												
Net Additions/Deductions to Oper. Inc.																	
		(677,501,000)			(677,501,000)												
Fuel and Purchased Power																	
565	PURCHASED POWER	-			-	F_PRPW	FUL									FUEL	
567	OTHER PURCHASED POWER EXPENSES	323,299			323,299	F_PRPW	FUL									FUEL	
	TOTAL	323,299			323,299												
Income Taxes																	
TAX	INCOME TAXES - STATE - PRESENT	(2,990,874)			(2,990,874)	F_INTAX	GNR							INCTAX			
TAX	INCOME TAXES - FEDERAL - PRESENT	16,330,026			16,330,026	F_INTAX	GNR							INCTAX			
TAX	INCOME TAXES - STATE - INCREASE	25,794,792			25,794,792	F_INTAX	GNR							GNR_DIST			
TAX	INCOME TAXES - FEDERAL - INCREASE	69,402,242			69,402,242	F_INTAX	GNR							GNR_DIST			
	TOTAL	108,536,187			108,536,187												
Operating Revenues																	
REV	TRANSMISSION REVENUES	-			-	F_REVNU	REV									REV_TRANS	
REV	DISTRIBUTION REVENUES	1,004,890,414			1,004,890,414	F_REVNU	REV									REV_DIST	
REV	STATE TAX ADJ SURCHARGE	-			-	F_REVNU	REV									REV_DIST	
REV	LATE PAYMENT CHARGES	15,305,520			15,305,520	F_REVNU	REV									REV_DIST	
REV	ANNUALIZATION	4,932,874			4,932,874	F_REVNU	REV									REV_DIST	
REV	MISCELLANEOUS SERVICE REVS	969,910			969,910	F_REVNU	REV									REV_DIST	
REV	RENT-ELECTRIC PROPERTY - TRAN	2,916,000			2,916,000	F_REVNU	REV									REV_TRANS	
REV	RENT-ELECTRIC PROPERTY - DIST	40,829,268			40,829,268	F_REVNU	REV									REV_TRANS	
REV	OTHER ELECTRIC REVENUE - TRAN	974,520,326			974,520,326	F_REVNU	REV									REV_TRANS	
REV	OTHER ELECTRIC REVENUE - DIST	3,024,960			3,024,960	F_REVNU	REV									REV_DIST	
REV	RESAL REVENUES	318,877			318,877	F_REVNU	REV									REV_DIST	
REV	BL REVENUES	348,811			348,811	F_REVNU	REV									REV_DIST	
REV	LATE PAYMENT CHARGES INCREASE	1,699,050			1,699,050	F_REVNU	REV									REV_DIST	
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Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

Line Ref.

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
RATE BASE							
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	2,206,600,018	-	2,206,600,018
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	412,699,312	-	412,699,312
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	258,469,160	-	258,469,160
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	1,263,306,323	-	1,263,306,323
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	357,014,301	-	357,014,301
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	152,691,932	-	152,691,932
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	313,713,573	-	313,713,573
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	122,609,518	-	122,609,518
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	133,428,398	-	133,428,398
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	17,099,279	-	17,099,279
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	237,559,338	-	237,559,338
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	186,814,138	-	186,814,138
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	7,312,787,619	7,312,787,619	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	6,785,648	1,023,373	5,762,275
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	14,309,000	(5,140,818)	19,449,818
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	(33,802,525)	(18,795,292)	(15,007,233)
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	155,133,000	-	155,133,000
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	(6,554,000)	-	(6,554,000)
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
RATE BASE							
			DEM	-	2,877,768,490	-	2,877,768,490
			CUS	-	2,777,682,799	-	2,777,682,799
			GNR	-	7,455,212,742	7,289,874,882	165,337,860
			REV	-	-	-	-
			FUL	-	-	-	-
		TOTAL		-	13,110,664,031	7,289,874,882	5,820,789,148

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

Line Ref.

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Plant-in Service					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	3,604,991,916	-	3,604,991,916
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	658,967,364	-	658,967,364
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	492,823,258	-	492,823,258
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	2,119,033,515	-	2,119,033,515
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	610,376,381	-	610,376,381
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	291,137,772	-	291,137,772
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	863,729,538	-	863,729,538
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	389,779,298	-	389,779,298
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	265,838,271	-	265,838,271
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	35,064,771	-	35,064,771
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	487,152,937	-	487,152,937
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	383,091,891	-	383,091,891
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	10,170,680,034	10,170,680,034	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Plant-in Service					-	-	-
			DEM	-	4,756,782,537	-	4,756,782,537
			CUS	-	5,445,204,374	-	5,445,204,374
			GNR	-	10,170,680,034	10,170,680,034	-
			REV	-	-	-	-
			FUL	-	-	-	-
			TOTAL	-	20,372,666,945	10,170,680,034	10,201,986,912

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Accumulated Reserve for Depreciation					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	933,311,344	-	933,311,344
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	162,263,768	-	162,263,768
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	169,739,012	-	169,739,012
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	584,716,312	-	584,716,312
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	175,624,948	-	175,624,948
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	100,274,159	-	100,274,159
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	436,770,582	-	436,770,582
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	217,572,038	-	217,572,038
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	98,108,184	-	98,108,184
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	14,629,173	-	14,629,173
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	203,242,291	-	203,242,291
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	159,827,577	-	159,827,577
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	1,487,623,982	1,487,623,982	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Accumulated Reserve for Depreciation					-	-	-
			DEM	-	1,265,314,123	-	1,265,314,123
			CUS	-	1,990,765,264	-	1,990,765,264
			GNR	-	1,487,623,982	1,487,623,982	-
			REV	-	-	-	-
			FUL	-	-	-	-
			TOTAL	-	4,743,703,369	1,487,623,982	3,256,079,387

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Rate Base Adjustments					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	(465,080,554)	-	(465,080,554)
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	(84,004,285)	-	(84,004,285)
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	(64,615,086)	-	(64,615,086)
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	(271,010,881)	-	(271,010,881)
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	(77,737,132)	-	(77,737,132)
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	(38,171,681)	-	(38,171,681)
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	(113,245,382)	-	(113,245,382)
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	(49,597,742)	-	(49,597,742)
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	(34,301,689)	-	(34,301,689)
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	(3,336,320)	-	(3,336,320)
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	(46,351,308)	-	(46,351,308)
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	(36,450,176)	-	(36,450,176)
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	(1,370,268,433)	(1,370,268,433)	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	6,785,648	1,023,373	5,762,275
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	14,309,000	(5,140,818)	19,449,818
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	(33,802,525)	(18,795,292)	(15,007,233)
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	155,133,000	-	155,133,000
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	(6,554,000)	-	(6,554,000)
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Rate Base Adjustments					-	-	-
			DEM	-	(613,699,925)	-	(613,699,925)
			CUS	-	(676,756,311)	-	(676,756,311)
			GNR	-	(1,227,843,310)	(1,393,181,170)	165,337,860
			REV	-	-	-	-
			FUL	-	-	-	-
			TOTAL	-	(2,518,299,546)	(1,393,181,170)	(1,125,118,376)

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

Line Ref.

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
O & M EXPENSES					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	89,127,060	-	89,127,060
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	24,900,739	-	24,900,739
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	1,743,807	-	1,743,807
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	71,466,645	-	71,466,645
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	23,777,531	-	23,777,531
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	1,030,163	-	1,030,163
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	28,192,138	-	28,192,138
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	8,157,383	-	8,157,383
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	4,582,499	-	4,582,499
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	6,888,932	-	6,888,932
F_CUSSV	CUS	Dist. Customer Service	F_CUSSV_CUS	DIST	105,890,861	-	105,890,861
F_CUSSV	CUS	Dist. And Resale Customer Service	F_CUSSV_CUS	CUST	67,150,886	-	67,150,886
F_CUSSV	CUS	Tran. Customer Service	F_CUSSV_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	38,111,992	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	35,129,369	-	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	5,123,000	-	5,123,000
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	300,000	-	300,000
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
O & M EXPENSES					-	-	-
			DEM		115,771,607	-	115,771,607
			CUS		355,549,028	-	317,437,037
			GNR		40,252,369	-	5,123,000
			REV		-	-	-
			FUL		-	-	-
			TOTAL		511,573,005	73,241,361	438,331,644

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Depreciation Expense					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	84,232,897	-	84,232,897
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	18,934,577	-	18,934,577
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	14,915,737	-	14,915,737
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	57,105,853	-	57,105,853
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	17,549,471	-	17,549,471
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	8,811,545	-	8,811,545
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	10,479,649	-	10,479,649
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	29,664,288	-	29,664,288
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	7,490,851	-	7,490,851
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	2,833,080	-	2,833,080
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	39,359,818	-	39,359,818
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	30,952,142	-	30,952,142
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	225,245,278	225,245,278	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	1,826,000	-	1,826,000
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Depreciation Expense					-	-	-
			DEM		118,083,212	-	118,083,212
			CUS		204,246,696	-	204,246,696
			GNR		227,071,278	225,245,278	1,826,000
			REV		-	-	-
			FUL		-	-	-
			TOTAL		549,401,186	225,245,278	324,155,908

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Taxes Other Than Income Taxes					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	13,984,790	-	13,984,790
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	3,005,975	-	3,005,975
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	1,450,258	-	1,450,258
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	9,274,500	-	9,274,500
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	2,816,774	-	2,816,774
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	856,747	-	856,747
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	2,541,744	-	2,541,744
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	1,818,494	-	1,818,494
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	1,028,655	-	1,028,655
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	665,076	-	665,076
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	9,239,860	-	9,239,860
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	7,266,128	-	7,266,128
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	94,137,000	94,137,000	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	79,885,453	-	79,885,453
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Taxes Other Than Income Taxes					-	-	-
			DEM		18,441,024	-	18,441,024
			CUS		35,507,976	-	35,507,976
			GNR		174,022,453	94,137,000	79,885,453
			REV		-	-	-
			FUL		-	-	-
			TOTAL		227,971,453	94,137,000	133,834,453

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Adjustments to Taxable Income					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	417,062	-	417,062
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	(948,118)	-	(948,118)
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	2,255,915	-	2,255,915
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	(2,270,533)	-	(2,270,533)
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	(991,992)	-	(991,992)
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	1,332,693	-	1,332,693
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	1,397,932	-	1,397,932
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	2,308,243	-	2,308,243
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	248,821	-	248,821
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	(1,551,734)	-	(1,551,734)
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	(21,558,161)	-	(21,558,161)
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	(16,953,109)	-	(16,953,109)
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	(317,092,000)	(317,092,000)	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	(198,021,020)	-	(198,021,020)
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Adjustments to Taxable Income					-	-	-
			DEM		1,724,859	-	1,724,859
			CUS		(38,037,839)	-	(38,037,839)
			GNR		(515,113,020)	(317,092,000)	(198,021,020)
			REV		-	-	-
			FUL		-	-	-
			TOTAL		(551,426,000)	(317,092,000)	(234,334,000)

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

Line Ref.

6

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
PA Special Deductions							
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	(10,153,592)	-	(10,153,592)
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	(2,163,777)	-	(2,163,777)
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	(1,956,956)	-	(1,956,956)
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	(6,601,822)	-	(6,601,822)
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	(1,995,707)	-	(1,995,707)
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	(1,156,082)	-	(1,156,082)
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	(1,458,983)	-	(1,458,983)
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	(3,590,985)	-	(3,590,985)
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	(910,529)	-	(910,529)
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	(190,555)	-	(190,555)
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	(2,647,372)	-	(2,647,372)
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	(2,081,865)	-	(2,081,865)
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	(90,937,000)	(90,937,000)	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	(229,774)	-	(229,774)
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
PA Special Deductions							
			DEM		(14,274,326)	-	(14,274,326)
			CUS		(20,633,901)	-	(20,633,901)
			GNR		(91,166,774)	(90,937,000)	(229,774)
			REV		-	-	-
			FUL		-	-	-
			TOTAL		(126,075,000)	(90,937,000)	(35,138,000)

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

Line Ref.

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Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Fuel and Purchased Power						-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	-	-	-
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	-	-	-
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	-	-	-
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	-	-	-
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	-	-	-
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	-	-	-
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	-	-	-
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	-	-	-
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	-	-	-
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	-	-	-
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	-	-	-
F_CUSSF	CUS	Dist. And Resale Customer Service	F_CUSSF_CUS	CUST	-	-	-
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	-	-	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	-	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	-	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	323,299	-	323,299
Fuel and Purchased Power						-	-
			DEM		-	-	-
			CUS		-	-	-
			GNR		-	-	-
			REV		-	-	-
			FUL		323,299	-	323,299
			TOTAL		323,299	-	323,299

Jurisdictional Cost of Service Study
Functionalization and Classification of Costs

Line Ref.

6

7

Function	Class	Functional Description	Func/Class	Allocator	Fully Projected Future Test Year	FERC Transmission	PUC Jurisdiction Distribution
Income Taxes					-	-	-
F_DSTPR	DEM	Dist. Primary Demand	F_DSTPR_DEM	PRI_DEM	-	-	-
F_DSTSC	DEM	Dist. Secondary Demand	F_DSTSC_DEM	SEC_DEM	-	-	-
F_TRANF	DEM	Transformer Demand	F_TRANF_DEM	SEC_DEM	-	-	-
F_DISTR	DEM	Dist. Primary Demand	F_DISTR_DEM	PRI_DEM	-	-	-
F_SERVS	DEM	#N/A	F_SERVS_DEM	SEC_DEM	-	-	-
F_DSTPR	CUS	Dist. Primary Customer	F_DSTPR_CUS	PRI_CUST	-	-	-
F_DSTSC	CUS	Dist. Secondary Customer	F_DSTSC_CUS	SEC_CUST	-	-	-
F_TRANF	CUS	Transformer Customer	F_TRANF_CUS	SEC_CUST	-	-	-
F_SERVS	CUS	Services Customer	F_SERVS_CUS	SEC_CUST	-	-	-
F_METER	CUS	Distribution Meters	F_METER_CUS	DIST	-	-	-
F_LIGHT	CUS	Lights	F_LIGHT_CUS	DIST	-	-	-
F_SERVS	CUS	Distribution Services	F_SERVS_CUS	DIST	-	-	-
F_CUSSF	CUS	Dist. Customer Service	F_CUSSF_CUS	DIST	-	-	-
F_CUSSF	CUS	Dist. And Resale Customer Servi	F_CUSSF_CUS	CUST	-	-	-
F_CUSSF	CUS	Tran. Customer Service	F_CUSSF_CUS	TRANS	-	-	-
F_TRANS	CUS	Tran. Direct Assignment	F_TRANS_CUS	TRANS	-	-	-
F_TRANS	GNR	Tran. Direct Assignment	F_TRANS_GNR	GNR_TRANS	-	-	-
F_CWRKC	GNR	Cash Working Capital - O&M	F_CWRKC_GNR	OM_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Tax	F_CWRKC_GNR	TAX_CWC	-	-	-
F_CWRKC	GNR	Cash Working Capital - Interest	F_CWRKC_GNR	INTRST_CWC	-	-	-
F_DISTR	GNR	Dist. Direct Assignment	F_DISTR_GNR	GNR_DIST	-	-	-
F_DISTR	CUS	Customer Deposits	F_DISTR_CUS	DEPOSIT	-	-	-
F_INTAX	GNR	Income Taxes	F_INTAX_GNR	INCTAX	13,339,152	-	-
F_INTAX	GNR	Income Tax Increase @ Proposer	F_INTAX_GNR	GNR_DIST	95,197,035	-	-
F_REVNU	REV	Transmission Revenue	F_REVNU_REV	REV_TRANS	-	-	-
F_REVNU	REV	Distribution Revenue	F_REVNU_REV	REV_DIST	-	-	-
F_PRPWR	FUL	Purchased Power	F_PRPWR_FUL	FUEL	-	-	-
Income Taxes					108,536,187	46,600,135	61,936,051
					-	-	-
					-	-	-
					108,536,187	46,600,135	61,936,051
					-	-	-
					-	-	-
TOTAL					108,536,187	46,600,135	61,936,051
					-	-	-
Operating Revenues					-	-	-
F_INTAX	REV	TRANSMISSION REVENUES		REV_TRANS	-	-	-
F_INTAX	REV	DISTRIBUTION REVENUES		REV_DIST	1,004,890,414	-	1,004,890,414
F_INTAX	REV	STATE TAX ADJ SURCHARGE		REV_DIST	-	-	-
F_INTAX	REV	LATE PAYMENT CHARGES		REV_DIST	15,305,520	-	15,305,520
F_INTAX	REV	ANNUALIZATION		REV_DIST	4,932,874	-	4,932,874
F_INTAX	REV	MISCELLANEOUS SERVICE REVS		REV_DIST	969,910	-	969,910
F_INTAX	REV	RENT-ELECTRIC PROPERTY - TRAN		REV_TRANS	2,916,000	-	-
F_INTAX	REV	RENT-ELECTRIC PROPERTY - DIST		REV_DIST	40,829,268	-	40,829,268
F_INTAX	REV	OTHER ELECTRIC REVENUE - TRAN		REV_TRANS	974,520,326	-	-
F_INTAX	REV	OTHER ELECTRIC REVENUE - DIST		REV_DIST	3,024,960	-	3,024,960
F_INTAX	REV	RESALE REVENUES		REV_DIST	318,877	-	318,877
##	REV	BL REVENUES		REV_DIST	348,811	-	348,811
##	REV	LATE PAYMENT CHARGES INCREASE		REV_DIST	1,699,050	-	1,699,050
Total					2,049,756,011	977,436,326	1,072,319,685

END

Jurisdictional Cost of Service Study

External Allocation Factors

					5	6
					FERC	PUC
					Transmission	Jurisdiction
Name	No.	Description		Total		Distribution
DEMAND ALLOCATORS						
PRI_DEM	1	Demand at Primary without Resale	DEM	100.00%	0.00%	100.00%
				1	0	1
SEC_DEM	2	Demand at Secondary	DEM	100.00%	0.00%	100.00%
				1	0	1
CUSTOMER ALLOCATORS						
PRI_CUST	3	Primary Customers	CUS	100.00%	0.00%	100.00%
				1	0	1
SEC_CUST	4	Secondary Customers	CUS	100.00%	0.00%	100.00%
				1	0	1
CUST	5	Total Customers	CUS	100.00%	0.00%	100.00%
				1	0	1
TRANS	6	Transmission	CUS	100.00%	100.00%	0.00%
				1	1	0
DIST	7	Distribution	CUS	100.00%	0.00%	100.00%
				1	0	1
DEPOSIT	8	Customer Deposits	CUS	100.00%	0.00%	100.00%
				1	0	1
GENERAL ALLOCATORS - DIRECT						
GNR_TRANS	9	Direct to Transmission	GNR	100.00%	100.00%	0.00%
				1	1	0
GNR_DIST	10	Direct to Distribution	GNR	100.00%	0.00%	100.00%
				1	0	1
GNR_RESALE	11	Direct to Resale	GNR	0.00%	0.00%	0.00%
				0	0	0
OM_CWC	12	Cash Working Capital	GNR	100.00%	15.08%	84.92%
				6,785,643	1,023,372	5,762,271
TAX_CWC	13	Cash Working Capital	GNR	100.00%	-35.93%	135.93%
				14,308,694	-5,140,708	19,449,403
INTRST_CWC	14	Cash Working Capital	GNR	100.00%	55.60%	44.40%
				-33,802,000	-18,795,000	-15,007,000
INCTAX	15	Income Tax	GNR	100.00%	349.35%	-249.35%
				13,339,159	46,600,158	-33,261,000
GRTTAX	16	GRT Tax	GNR	100.00%	0.00%	100.00%
				60,622,237	0	60,622,237

Jurisdictional Cost of Service Study

External Allocation Factors

					5	6
					FERC	PUC
					Transmission	Jurisdiction
Name	No.	Description		Total		Distribution
REVENUE ALLOCATORS						
REV_DIST	17	Distribution Revenue	REV	100.00%	0.00%	100.00%
				1	0	1
REV_TRANS	18	Transmission Revenue	REV	100.00%	100.00%	0.00%
				1	1	0
REV_RESALE	19	Resale Revenue	REV	0.00%	0.00%	0.00%
				0	0	0
FUEL ALLOCATORS						
FUEL	20		FUL	100.00%	0.00%	100.00%
				1	0	1
OTHER ALLOCATORS						
ROR	21	Rate of Return	OTHER	100.00%	100.00%	100.00%
				8.56%	8.56%	8.56%
ROD	22	Weighted Cost of Debt	OTHER	100.00%	100.00%	100.00%
				2.23%	2.23%	2.23%
ROE	23	Weighted Cost of Equity	OTHER	100.00%	100.00%	100.00%
				6.33%	6.33%	6.33%
DEBT_CAP	24	Debt Capitalization	OTHER	100.00%	100.00%	100.00%
				43.95%	43.95%	43.95%
EQUITY_CAP	25	Equity Capitalization	OTHER	100.00%	100.00%	100.00%
				56.05%	56.05%	56.05%

Jurisdictional Cost of Service Study

Internal Allocation Factors

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Internal Allocators						
	Allocator Name	Description	Total	Transmission	Distribution	
TRUE	DPLT	Distribution Plant less Internals	9,026,271,329 100.00%	- 0.00%	9,026,271,329 100.00%	
TRUE	PLT_360	Acct 360 Distribution Plant	113,493,096 100.00%	- 0.00%	113,493,096 100.00%	
TRUE	PLT_362	Acct 362 Distribution Plant	1,071,977,540 100.00%	- 0.00%	1,071,977,540 100.00%	
TRUE	PLT_364	Acct 364 Distribution Plant	1,881,731,594 100.00%	- 0.00%	1,881,731,594 100.00%	
TRUE	PLT_365	Acct 365 Distribution Plant	1,947,235,550 100.00%	- 0.00%	1,947,235,550 100.00%	
TRUE	PLT_365NORSL	Acct 365 Distribution Plant less Resale	1,947,235,550 100.00%	- 0.00%	1,947,235,550 100.00%	
TRUE	PLT_366	Acct 366 Distribution Plant	377,893,800 100.00%	- 0.00%	377,893,800 100.00%	
TRUE	PLT_367	Acct 367 Distribution Plant	994,823,277 100.00%	- 0.00%	994,823,277 100.00%	
TRUE	PLT_360_2	Acct 360 & 362 Distribution Plant	1,249,198,571 100.00%	- 0.00%	1,249,198,571 100.00%	
TRUE	PLT_360_1	Acct 360 & 361 Distribution Plant	177,221,031 100.00%	- 0.00%	177,221,031 100.00%	
TRUE	PLT_364_5	Acct 364 & 365 Distribution Plant	3,828,967,143 100.00%	- 0.00%	3,828,967,143 100.00%	
TRUE	PLT_366_7	Acct 366 & 367 Distribution Plant	1,372,717,077 100.00%	- 0.00%	1,372,717,077 100.00%	
TRUE	PLT_370	Acct 370 Distribution Plant	341,126,522 100.00%	- 0.00%	341,126,522 100.00%	
TRUE	TRNPLT	Transmission Plant	10,162,924,834 100.00%	10,162,924,834 100.00%	- 0.00%	
TRUE	TOTDPLT	Distribution Plant	9,139,764,425 100.00%	- 0.00%	9,139,764,425 100.00%	
TRUE	DEPR	Total Depreciation Expense	549,401,186 100.00%	225,245,278 41.00%	324,155,908 59.00%	
TRUE	DEPR_DPLT	Distribution Depreciation Expense	264,935,209 100.00%	- 0.00%	264,935,209 100.00%	
TRUE	DEPR_GIPLT	General and Intangible Depreciation Expense	59,220,699 100.00%	- 0.00%	59,220,699 100.00%	
TRUE	DISTOPLBR	Distribution Operations Labor	18,574,359	-	18,574,359	

Jurisdictional Cost of Service Study

Internal Allocation Factors

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Internal Allocators					
	Allocator Name	Description	Total	Transmission	Distribution
			100.00%	0.00%	100.00%
TRUE	DMAINTLBR	Distribution Maintenance Labor	11,964,895	-	11,964,895
			100.00%	0.00%	100.00%
TRUE	LABOR_NOTRN	Labor Expense Excluding A&G and Transmission Labor	74,938,461	-	74,938,461
			100.00%	0.00%	100.00%
TRUE	LABOR	Labor Expense	81,788,028	6,849,567	74,938,461
			100.00%	8.37%	91.63%
TRUE	TOTPLT	Total Plant in Service	20,372,666,945	10,170,680,034	10,201,986,912
			100.00%	49.92%	50.08%
TRUE	LBRANDPLT	50% Labor 50% Plant Excluding Account 303	10,227,227,487	5,088,764,800	5,138,462,686
			100.00%	49.76%	50.24%
TRUE	METERS	Meter Plant	341,126,522	-	341,126,522
			100.00%	0.00%	100.00%
TRUE	DEFRTX	Deferred Income Tax	136,536,000	90,066,000	46,470,000
			100.00%	65.97%	34.03%
TRUE	CUSTACCTLBR	Customer Accounts Labor	15,345,829	-	15,345,829
			100.00%	0.00%	100.00%
TRUE	CAPSTCK	Capital Stock Increase	2,460,000	-	2,460,000
			100.00%	0.00%	100.00%
TRUE	PUBREALTY	Public Utility Realty	3,110,000	1,610,000	1,500,000
			100.00%	51.77%	48.23%
TRUE	904INCREASE	Uncollectible Increase	6,421,504	-	6,421,504
			100.00%	0.00%	100.00%
TRUE	GRTINCREASE	GRT Increase	22,406,453	-	22,406,453
			100.00%	0.00%	100.00%
TRUE	ITC	Investment Tax Credit	(31,000)	(16,000)	(15,000)
			100.00%	51.61%	48.39%
TRUE	PUC	PUC FEE INCRAESE	1,110,654	-	1,110,654
			100.00%	0.00%	100.00%

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION
PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-2R
Witness: Bickey Rimal**

Docket No. R-2025-3057164

PPL ELECTRIC UTILITIES CORPORATION
EXHIBIT BR-2R
DISTRIBUTION FUNCTIONALIZATION & CLASSIFICATION STUDIES
FUNCTIONAL AND ALLOCATION STUDIES – INDEX

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PPL ELECTRIC UTILITIES CORPORATION EXHIBIT BR-2R

SECTION I FUNCTIONAL STUDIES

DISTRIBUTION PRIMARY SECONDARY SPLIT & MINIMUM SYSTEM STUDY

The below exhibit provide the results of special studies used to functionalize and classify PPL Electric's distribution plant.

Distribution plant is functionalized into the following categories:

- Substations
- Poles Towers & Fixtures – Primary and Secondary
- Overhead Lines – Primary and Secondary
- Underground Lines – Primary and Secondary
- Underground Conduits – Primary and Secondary
- Line transformers
- Services
- Meters
- Area Lighting
- Street Lighting

In order to split some accounts between primary and secondary, a primary secondary split study is conducted to sub-functionalize distribution plant between those two voltage categories.

The plant balances for both the primary and secondary system are then classified into demand and customer components based on a "minimum size system" study.

Distribution Plant - Functionalization

Land and Land Rights (Account 360)

Land and Land Rights is functionalized based on the total functionalization of distribution plant.

Structures and Improvements & Substations (Accounts 361 and 362)

The costs associated with Structures and Improvements (361) and Substations (362) are functionalized as primary distribution plant and allocated on a demand basis.

Poles, Towers and Fixtures (Account 364)

Account 364 is segmented into primary and secondary functions based on plant account retirement units. However, there are a few poles and associated attachments that cannot be categorized directly as primary or secondary. For example, there are investments in 40-foot poles that are categorized as “split”, which can be assigned to either the primary or secondary function. The assignment for these types of poles is based on the ratio of investment in overhead conductors assigned to the primary and secondary functions. See details regarding the functionalization of Overhead Conductors and Devices (Account 365) for the development of this ratio. The attachments associated with wooden poles are assigned to the primary and secondary functions based on the number of poles assigned to each function. The number of poles used to segment the primary function is doubled to reflect the fact that primary poles require twice the investment in attachments.

The remaining investment in Account 364 (hardware and devices, guys, anchors, etc.) is assigned to the primary and secondary functions based on ratio developed from the steps above.

Overhead Conductors and Devices (Account 365)

Overhead conductors were functionalized between primary and secondary voltages by utilizing length of conductors and the replacement costs of conductors serving primary versus secondary distribution systems. Using PPL Electric’s asset management system, the length of conductors carrying primary versus secondary voltage was obtained. For each conductor type, the length of the conductor was multiplied by the replacement cost of that conductor to obtain the total cost of that conductor type. For conductor types that are no longer used, a replacement conductor was identified, and the cost of that replacement conductor was used in the analysis. Using the total costs of all conductors by voltage, the ratio of primary conductors to secondary conductors was calculated.

Underground Conductors and Devices (Account 367)

Similar to Overhead conductors, underground conductors were functionalized between primary and secondary voltages by utilizing length of conductors and the replacement costs of conductors serving primary versus secondary distribution systems.

Underground Conduit (Account 366)

The functionalization of Underground Conduit (Account 366) is based on the functionalization of underground conductor. Accordingly, the same percentages of primary and secondary was applied to underground conduits.

Line Transformers (Account 368)

The investment in Line Transformers (Account 368) is considered to be a 100% secondary function.

Services (Account 369)

The investment in Services (Account 369) is considered to be a 100% secondary function.

Area Lighting (Account 371)

The investment in area lighting is considered to be a 100% secondary function.

Street Lighting (Account 373)

The investment in street lighting is considered to be a 100% secondary function.

Distribution Plant - Classification Minimum Size System Study

A "minimum size system" study was conducted to determine the demand and customer components of the primary and secondary voltage level distribution plant accounts. The "minimum size" method, which is described in the NARUC Cost Allocation Manual, was used as a guide in the preparation of this study.

The study involved the determination of the current cost of the "minimum size" plant investment (poles, conductors, cables, and line transformers) that is necessary to provide reliable electric service to customers.

Poles, Towers & Fixtures (Account 364)

The Primary and Secondary Analysis for poles described above provided the total cost and total count of primary and secondary poles. This total count of primary poles was multiplied by the embedded cost of a minimum sized primary pole to calculate the minimum system cost of primary poles. This was then compared to the total embedded cost of primary poles to determine the portion of primary poles that is customer related and demand related. A similar analysis was conducted for secondary poles.

Overhead Conductors and Devices (Account 365)

The Primary and Secondary Analysis for overhead conductors described above provided the total cost and total circuit miles of primary and secondary conductors. A hypothetical minimum system replacement cost was calculated by taking the total circuit feet of overhead conductor associated with the primary system and multiplying it by the replacement cost of the minimum sized primary overhead conductor. The minimum system replacement cost was then compared to the total system replacement costs to arrive at the customer related and demand related costs for primary overhead conductors. A similar analysis was conducted for secondary overhead conductors.

Underground Conduit (Account 366)

This account is assigned the same customer/demand ratio as Underground Conductors (Account 367).

Underground Conductors (Account 367)

The Primary and Secondary Analysis for underground conductors described above provided the total cost and total circuit miles of primary and secondary conductors. A hypothetical minimum system replacement cost was calculated by taking the total circuit feet of underground conductor associated with the primary system and multiplying it by

the replacement cost of the minimum sized primary underground conductor. The minimum system replacement cost was then compared to the total system replacement costs to arrive at the customer related and demand related costs for primary underground conductors. A similar analysis was conducted for secondary underground conductors.

Line Transformers (Account 368)

Using PPL Electric's asset management system, the count of line transformer by type (overhead, pad-mounted, sub-surface, etc.) was obtained. For each transformer type, the number of transformers was multiplied by the replacement cost of that transformer type to obtain the total cost associated with that transformer type. For transformer types that are no longer used, a replacement transformer was identified, and the cost of that replacement transformer was used in the analysis. A hypothetical minimum system replacement cost was calculated by multiplying the total count of line transformers by the replacement cost of the minimum sized transformer. The minimum system replacement cost was then compared to the total system replacement costs to arrive at the customer related and demand related costs for line transformers.

Operation & Maintenance Expense

The process of functionalizing distribution operation & maintenance ("O&M") expense begins with the proration of Supervision and Engineering (Accounts 580 and 590) expense to the other distribution O&M accounts based on the ratio of the labor component of each account to the total distribution labor cost. After prorating the Supervision and Engineering expense, the other O&M accounts are functionalized and classified based on the functionalization of the corresponding distribution plant accounts.

The following tables provide details on this process, first showing the split of distribution accounts between primary and secondary and then the development of the minimum system study.

PPL Electric Utilities
Allocated Cost of Service Study
Primary Secondary Sub-Functionalization Study
Pole Analysis

Line No.		
1	<u>Poles - Account 364</u>	
2	Primary Cost	\$ 855,108,408
3	Secondary Cost	\$ 312,278,958
4	Total Cost	\$ 1,167,387,366
5	Primary (%)	73%
6	Secondary (%)	27%

**PPL Electric Utilities
Allocated Cost of Service Study
Primary Secondary Sub-Functionalization Study
Conductor Analysis**

Line No.

1	<u>Overhead Conductors - Account 365</u>		
2	Primary Cost	\$	679,057,269
3	Secondary Cost	\$	269,635,555
4	Total Cost	\$	948,692,824
5	Primary (%)		72%
6	Secondary (%)		28%

7	<u>Underground Conductors & Conduit - Account 367 & 366</u>		
8	Primary Cost	\$	858,088,751
9	Secondary Cost	\$	39,338,181
10	Total Cost	\$	897,426,932
11	Primary (%)		96%
12	Secondary (%)		4%

**PPL Electric Utilities
Allocated Cost of Service Study
Minimum System Study
Pole Minimum System Analysis**

Line No.	Poles - Account 364	
1	Total Pole Cost	\$ 1,167,387,366
2	Primary Poles	\$ 855,108,408
3	Primary Poles (# of poles)	558,055
4	Minimum Cost (Cost of 40 foot pole)	\$ 934
5	Minimum Cost to Provide Primary (line 4 * line 5)	\$ 521,359,795
6	Customer - Poles (line 6 / line 2)	60.97%
7	Demand - Poles	39.03%
8	Secondary Poles	\$ 312,278,958
9	Secondary Poles (# of poles)	346,894
10	Minimum Cost (Cost of 35 foot pole)	\$ 720
11	Minimum Cost to Provide Secondary (line 11 * line 12)	\$ 249,684,941
12	Customer - Poles (line 13 / line 9)	79.96%
13	Demand - Poles	20.04%

**PPL Electric Utilities
Allocated Cost of Service Study
Minimum System Study
Conductor Minimum System Analysis**

Line No.

1	Overhead Conductors - Account 365		
2	Total Cost of Overhead Conductors	\$	948,692,824
3	Primary Conductor	\$	679,057,269
4	Total Circuit Feet of OH Primary Conductors		148,832,142
5	Minimum Conductor Cost Per 100 Feet - OH (1/0 AL + Neutral)	\$	206
6	Minimum Cost to Provide Primary (line 4 * line 5)	\$	306,415,614
7	Customer - O/H		45.1%
8	Demand - O/H		54.9%
9	Secondary Conductor	\$	269,635,555
10	Total Circuit Feet of OH Secondary Conductors		44,308,348
11	Minimum Conductor Cost Per 100 Feet - OH (1/0 TPX)	\$	128
12	Minimum Cost to Provide Secondary (line 10 * line 11)	\$	56,927,365
13	Customer - O/H		21.1%
14	Demand - O/H		78.9%
15	Underground Conductors & Conduit - Account 367 & 366		
16	Total Cost of Underground Conductors	\$	897,426,932
17	Primary Conductor	\$	858,088,751
18	Total Circuit Feet of UG Primary Conductors		43,108,664
19	Minimum Conductor Cost Per 100 Feet - OH (3-#2 AL XLPE)	\$	641
20	Minimum Cost to Provide Primary (line 18 * line 19)	\$	276,309,292
21	Customer - U/G		32.2%
22	Demand - U/G		67.8%
23	Secondary Conductor	\$	39,338,181
24	Total Circuit Feet of UG Secondary Conductors		4,609,962
25	Minimum Conductor Cost Per 100 Feet - OH (4/0 AL TPX)	\$	238
26	Minimum Cost to Provide Secondary (line 24 * line 25)	\$	10,958,340
27	Customer - U/G		27.9%
28	Demand - U/G		72.1%

**PPL Electric Utilities
Allocated Cost of Service Study
Minimum System Study
Transformer Minimum System Analysis**

Line No.	Line Transformer - Account 368	
1	Total Cost	\$ 2,151,238,508
2	Total Count	670,741
3	Minimum Transformer Size	10 KVA
4	Minimum Transformer Cost (per Transformer)	\$ 1,191
5	Minimum Transformer Cost (All Transformers)	\$ 798,900,408
6	Customer	37%
7	Demand	63%

PPL ELECTRIC UTILITIES CORPORATION EXHIBIT BR-2R

SECTION II DEVELOPMENT OF ALLOCATORS FOR PENNSYLVANIA RETAIL CUSTOMERS

The first part of this section provides a listing of all the allocators used in the ACOSS. Details are then provided for the development of the allocation of meter costs, transformers and services. A summary of the methods employed to develop these allocators is provided below.

Meters (Account 370)

A meter study was conducted to develop the meters allocator. Meter weights were developed for each customer class based on the number and type(s) of meters installed for each rate class and the associated costs of each type of meter. The analysis also accounted for the incremental cost associated with transformer rated meters. The total meter cost along with necessary equipment provided an estimate of the relative cost of providing metering service for each rate class. The relative-weight factor was then multiplied by the number of customers in the class to develop the meter allocation factors for each test year.

Services (Account 369)

The service allocator is used to allocate the service-related cost contained in FERC Account 369. The service allocator was developed based on a sample of recent service installations. For each rate class, the length and type of service installed using recent installation data was obtained from the Company. The total cost of service installation for each rate class was calculated by multiplying the length of each service installation by the replacement cost of that service type. A cost per installation was calculated by each class and this information was used to develop a weighting factor for each class. This weighting factor was ultimately used to develop the service allocator for each of the three test years.

Demand Allocators

The non-coincident peak (NCP) demand method was utilized to allocate demand-related distribution system costs. NCP refers to the highest level of demand that an individual class experienced during the year or month. The NCP information was based on the AMI meter reading for each customer class for the historical test year. The historical NCP was divided by the number of customers to calculate the NCP per customer for each class. This value was then multiplied by the forecasted number of customers in

FPFTY to estimate the NCP for FPFTY. For the LP-5 class, which is forecasted to have significant growth in load, NCP per MWh was used to estimate the NCP for FPFTY.

An Average and Excess (A&E) demand allocator was also calculated and is provided for reference within this Exhibit.

Other Allocators

This section also provides summary of other allocators used with the study:

- Customer Counts by Class
- Revenue by Class
- Usage by Class
- Uncollectible Expense by Class
- Customer Deposits by Class
- Late Payments by Class
- System Loss Factors

PPL Electric Utilities
Class Allocation Factors
For the Twelve Month Period Ending June 30, 2027

Line
No.

Name	Description	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL

DEMAND ALLOCATORS

1	FPFTY	<u>NCPs @ Primary</u> PRI_DEM_FPFTY NCP @ Primary 7,297,925										
		3,947,776	95,710	411,368	1,746,651	1,067,014	-	12,068	17,337			
2	FPFTY	<u>NCPs @ Secondary</u> SEC_DEM_FPFTY NCP @ Secondary 6,076,221										
		3,849,767	93,334	401,156	1,703,288	-	-	11,769	16,906			
3	FPFTY	<u>NCPs @ Secondary for Services</u> Adjustment Factor										
		1.00	1.00	1.00	1.00	1.00	1.00	1.00	-			
		SRV_DEM_FPFTY NCP @ Secondary for Services 6,059,314	3,849,767	93,334	401,156	1,703,288	-	-	11,769	-		
4	FPFTY	<u>Billing Demand</u> BILL_KW_FPFTY KW Billing Determinants 48,977,538										
		-	-	9,138,797	25,219,929	14,316,117	70,926	231,768	-			

PPL Electric Utilities
Class Allocation Factors
For the Twelve Month Period Ending June 30, 2027

Line No.	Name	Description	Total	Residential RS	Residential- Thermal Storage RTS	Small General Service - Sec. Voltage GS-1	Large General Service - Sec. Voltage GS-3	Large General Service - 12 KV LP-4	Large General Service - 69 KV or Higher LP-5	Separate Meter General Space Heating Service GH-2	Street Lighting/Area Lighting SL/AL
CUSTOMER ALLOCATORS											
<u>Average Customer Count</u>											
5	FPFTY	CUST_FPFTY No. of Customers	1,503,765	1,300,277	11,564	147,424	39,839	1,237	166	1,477	1,781
<u>Number of Customers Using Primary System</u>											
6	FPFTY	PRI_CUST_FPFTY No. of Customers	1,503,599	1,300,277	11,564	147,424	39,839	1,237	-	1,477	1,781
<u>Number of Customers Using Secondary System</u>											
7	FPFTY	SEC_CUST_FPFTY No. of Customers	1,502,362	1,300,277	11,564	147,424	39,839	-	-	1,477	1,781
<u>Allocation of Meter Investments</u>											
8		Meter Costs Per Customer		144	161	230	1,304	11,377	41,467	502	-
9		Weighting Factor		1.00	1.12	1.60	9.07	79.15	288.49	3.50	-
10	FPFTY	METERS_FPFTY Meters (Wtd Cust)	2,061,903	1,300,277	12,955	236,184	361,520	97,882	47,921	5,164	-
<u>Allocation of Services</u>											
11	FPFTY	SERV_FPFTY Weighting Factor		1	1	2	4	-	-	2	-
		Services (Wtd Cust)	1,720,793	1,300,277	11,564	232,748	173,872	-	-	2,332	-
<u>Gross Write-Offs</u>											
12	FPFTY	GRSWRTOFF_FPFTY Uncollectibles (Account 904)	33,659,175	30,642,166	103,951	1,261,953	1,415,506	219,686	8,976	6,937	-
<u>Customer Deposits</u>											
13	FPFTY	DEPOSIT_FPFTY Customer Deposits	5,933,674	1,792,042	11,255	1,387,352	2,588,203	98,939	-	13,142	42,741
<u>Meter Reading</u>											
14		Adjustment Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00	-
15	FPFTY	MTREAD_FPFTY Customer Count w/o SL/AL	1,501,984	1,300,277	11,564	147,424	39,839	1,237	166	1,477	-
<u>Direct Assignment of Area Lighting</u>											
16	FPFTY	AREALGT_FPFTY	1	-	-	-	-	-	-	-	1
<u>Direct Assignment of Street Lighting</u>											
17	FPFTY	STTRLGT_FPFTY	1	-	-	-	-	-	-	-	1
<u>Customer Charge Billing Determinants</u>											
18	FPFTY	CC_BILLDET_FPFTY	18,045,181	15,603,324	138,767	1,769,083	478,071	14,840	1,993	17,726	21,377

Demand Allocators

FPFTY						
Demand at Primary and Secondary Voltage (KW)						
Rate Class	NCP @ Meter	Measured at	NCP@ Generation	NCP@ Primary	NCP@ Secondary	Served At
RS	3,849,767	Meter	4,159,567	3,947,776	3,849,767	Secondary
RTS	93,334	Meter	100,845	95,710	93,334	Secondary
GS-1	401,156	Meter	433,438	411,368	401,156	Secondary
GS-3	1,703,288	Meter	1,840,356	1,746,651	1,703,288	Secondary
LP-4	1,067,014	Meter	1,124,258	1,067,014		Primary
LP-5	1,932,014	Meter	1,983,838			Transmission
GH-2	11,769	Meter	12,716	12,068	11,769	Secondary
SL/AL	16,906	Meter	18,267	17,337	16,906	Secondary

	Transmission	Primary	Secondary
Loss Factors from Generation	1.02682410	1.05364821	1.08047231
Loss from Primary to Secondary		1.02545831	

Average And Excess Demand Allocators

FPFTY

Rate Class	Energy @ Generation (KWH)	Average Demand @ Generation (KW)	Class Maximum Demand @ Generation (KW)	Class Excess	Average Allocator Component	Excess Allocator Component	Average & Excess Allocator
RS	15,359,918,501	1,753,415	4,159,567	2,406,151	21.40%	19.69%	41.09%
RTS	249,522,147	28,484	100,845	72,361	0.35%	0.59%	0.94%
GS-1	1,998,925,951	228,188	433,438	205,250	2.78%	1.68%	4.46%
GS-3	8,900,396,977	1,016,027	1,840,356	824,329	12.40%	6.75%	19.15%
LP-4	6,355,685,370	725,535	1,124,258	398,723	8.85%	3.26%	12.12%
LP-5	12,425,021,008	1,418,381	1,983,838	565,457	17.31%	4.63%	21.94%
GH-2	38,131,548	4,353	12,716	8,363	0.05%	0.07%	0.12%
SL/AL	79,333,594	9,056	18,267	9,211	0.11%	0.08%	0.19%
Total	45,406,935,096	5,183,440	9,673,284	4,489,844	63.25%	36.75%	100.00%

Meters Allocator

Meter Costs by Rate Class

	Total Costs	Customers	Cost Per Customer	Scaling
RS	185,140,893	1,288,046	143.74	1.00
RTS	1,876,116	11,651	161.03	1.12
GS-1	34,024,939	147,755	230.28	1.60
GS-3	51,205,122	39,257	1,304.35	9.07
LP-4	13,862,147	1,218	11,377.18	79.15
LP-5	6,728,042	162	41,467.13	288.49
GH-2	761,857	1,516	502.46	3.50
SL/AL	-	1,764	0.00	0.00
Total	293,599,116	1,491,370		

Services Allocator

Estimated Service Costs by Rate Class

	Total Installations	Total Cost (\$)	Avg Cost (\$/per Service)	Scaling
RS				1.00
RTS	10,577	14,062,462	1,329.53	1.00
GS-1	2,430	5,100,631	2,099.02	1.58
GS-3	1,122	6,510,445	5,802.54	4.36
LP-4	-	-		0.00
LP-5	-	-		0.00
GH-2	-	-	2,099.02	1.58
SL/AL	-	-		0.00

Customer Count by Rate Class

Total Customer Count by Rate Class

	FPFTY	Voltage
RS	1,300,277	Secondary
RTS	11,564	Secondary
GS-1	147,424	Secondary
GS-3	39,839	Secondary
LP-4	1,237	Primary
LP-5	166	Transmission
GH-2	1,477	Secondary
SL/AL	1,781	Secondary
Grand Total	1,503,765	
Total	1,503,765	

Primary/Secondary Customer Count by Rate Class

	FPFTY
RS	1,300,277
RTS	11,564
GS-1	147,424
GS-3	39,839
LP-4	1,237
LP-5	-
GH-2	1,477
SL/AL	1,781
Total	1,503,599

Secondary Customer Count by Rate Class

	FPFTY
RS	1,300,277
RTS	11,564
GS-1	147,424
GS-3	39,839
LP-4	-
LP-5	-
GH-2	1,477
SL/AL	1,781
Total	1,502,362

Annual Revenue (\$) By Rate Code

FPFTY		
Rate Code	Unadjusted Revenue (\$)	Annualization Adjustments
RS	723,522,983	3,863,271
RTS	7,210,947	(91,877)
GS-1	77,988,150	20,256
GS-3	126,302,233	890,656
LP-4	40,702,597	220,882
LP-5	1,892,576	8,182
LPEP	-	-
GH-2	1,351,205	(5,137)
SL/AL	24,741,294	23,494
Total	\$1,003,711,985	\$4,929,729

Distribution Revenue By Rate Class

Rate Code	FPFTY (w/ Riders)	FPFTY (Rider)	FPFTY
RS	762,996,323	40,754,535	722,241,788
RTS	8,448,674	476,235	7,972,439
GS-1	84,595,764	5,832,688	78,763,076
GS-3	133,293,534	4,107,858	129,185,676
LP-4	40,988,303	2,005,324	38,982,979
LP-5	1,959,078	(20,970)	1,980,048
GH-2	1,373,487	66,894	1,306,593
SL/AL	24,698,899	241,084	24,457,815
Total	1,058,354,062	53,463,648	1,004,890,414

Annual Sales (MWh) By Rate Class

Rate Code	FPFTY	Voltage Level	Loss Factor Adjustment	FPFTY
				Annualized Sales @ Generation (MWh) By Rate Class
RS	14,215,930	Secondary	1.08	15,359,919
RTS	230,938	Secondary	1.08	249,522
GS-1	1,850,048	Secondary	1.08	1,998,926
GS-3	8,237,506	Secondary	1.08	8,900,397
LP-4	6,032,075	Primary	1.05	6,355,685
LP-5	12,100,438	Transmission	1.03	12,425,021
GH-2	35,292	Secondary	1.08	38,132
SL/AL	73,425	Secondary	1.08	79,334
Total	42,775,651			45,406,935

Uncollectibles (Account 904) By Rate Class

Rate Code	FPFTY
RS	30,642,166
RTS	103,951
GS-1	1,261,953
GS-3	1,415,506
LP-4	219,686
LP-5	8,976
GH-2	6,937
SL/AL	-
Total	33,659,175

Customer Deposits By Rate Class

Rate Code	FPFTY
GH-2	13,142
GS-1	1,387,352
GS-3	2,588,203
LP-4	98,939
LP-5	-
RS	1,792,042
RTS	11,255
SL/AL	42,741
Total	5,933,674

Late Payments By Rate Class

Rate Code	FPFTY
GH-2	19,248
GS-1	1,362,554
GS-3	1,784,316
LP-4	542,187
LP-5	81,903
RS	11,420,504
RTS	83,834
SL/AL	-
Total	15,294,546

System Loss Factors

VOLTAGE LEVEL	LOSS FACTOR
SECONDARY	1.08047231
PRIMARY	1.05364821
TRANSMISSION	1.02682410
Loss from Primary to Secondary	1.02545831

WITNESS: Bickey Rimal

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Office of Small Business Advocate (OSBA)
Dated December 10, 2025
Docket No. R-2025-3057164

OSBA II-2

Reference Statement No. 1, page 19, response to OCA-I-1, Attachment 165 (Retail External Allocators), and response to OCA-I-1, Attachment 168 (Wire Installation Data):

- a. Statement No. 1 states that the Company developed the weighting factors for the services allocator by calculating a cost per installation for each class. However, based on the referenced workpapers, the Company appears to calculate the weighting factor based on the average cost per foot of service line within each class. Please clarify this discrepancy and provide an updated analysis if necessary.
- b. Please explain the logic for applying the weighting factor to the customer count for each class.

PPL Electric
Response

- a. The weighting factors calculated in the “OCA I-1 Attachment 168 Rimal: Service_Wire_Installation_Data - Updated by MDH Rev 2 (Service Costs)” are not correct. The weighting factor should have been based on cost per installation and not cost per foot of service line. The updated weighting factor calculation is provided as OSBA II-2 Attachment 1. Please note that making this correction will change the results of the Allocated Cost of Service Study (“ACOSS”). A comparison of the Index Rate of Return after making this correction is provided as OSBA II-2 Attachment 2. This attachment also compares the change in ACOSS revenue requirement by class, as well as mitigated revenue requirement by class. As shown in the attachment, this correction will shift revenue requirements from residential classes to some of the general service classes (GS-1, GS-3, and GH-2). The Company will provide the full package (i.e., updated ACOSS and updated exhibits) incorporating this correction as part of the Company’s rebuttal testimony and exhibits.

WITNESS: Bickey Rimal

- b. As explained in subpart (a) of this response, the weighting factor should have been based on cost per service installation instead of cost per foot. If the weighting factor is based on cost per installation, it is reasonable to apply the weighting factor to the customer counts for each service class.

Service Wire Installation Cost

	Total Installations	Total Cost (\$)	Avg Cost (\$/per Service)	Weight
Residential	10,577	\$ 14,062,462	\$ 1,329.53	1.00
GS1	2,430	\$ 5,100,631	\$ 2,099.02	1.58
GS3	1,122	\$ 6,510,445	\$ 5,802.54	4.36

Correction made on 12/15/2025

Wire Type	Wire Type Description	Discipline (Count of Installation)	CU Quantity (Average Length)	Configuration	Configuration	Rate Class	Price per foot	Total Length	Total Cost
C1-0TX-FTST-1	Overhead 1/0 Triplex from pole	70	59	Overhead	DSXO	Residential	\$ 12.12	4,130	\$ 50,056
CTX4-0ALST-1	Underground 4/0 Triplex - Connected to overhead transformer	59	124	Overhead	DSXO	Residential	\$ 12.97	7,316	\$ 94,889
C4TX-FTST-1	OH SER-4 TRIPLEX FROM POLE	34	73	Overhead	DSXO	Residential	\$ 11.50	2,482	\$ 28,543
C4-0TX-FTST-1	Overhead 4/0 Triplex from pole	30	45	Overhead	DSXO	Residential	\$ 12.87	1,350	\$ 17,375
CTX350ALST-1	UG SER TX-CBL+CONN-3C-2 350+4/0N	29	145	Overhead	DSXO	Residential	\$ 14.06	4,205	\$ 59,122
CTX1-0ALST-1	UG SER TX-CBL+CONN-3C-2 1/0+2N	21	83	Overhead	DSXO	Residential	\$ 12.10	1,743	\$ 21,090
C4-0TRANSST-1	Underground Aluminum Service 4/0 + 2/0 Neutral from pad mounted transformer	6,744	141	Underground	DSXU	Residential	\$ 12.97	950,904	\$ 12,333,225
C1-0TRANSST-1	Underground Aluminum Service 1/0 + #2 Neutral from pad mounted transformer	2,050	41	Underground	DSXU	Residential	\$ 12.10	84,050	\$ 1,017,005
C350TRANSST-1	Underground Aluminum Service 350 + 4/0 Neutral from pad mounted transformer	1,310	23	Underground	DSXU	Residential	\$ 14.06	30,130	\$ 423,628
C500TRANSST-1	Underground Aluminum Service 500 + 350 Neutral from pad mounted transformer	170	5	Underground	DSXU	Residential	\$ 15.49	850	\$ 13,167
C1-0TX-FTST-1	Overhead 1/0 Triplex from pole	60	6	Underground	DSXU	Residential	\$ 12.12	360	\$ 4,363
C4-0TRANSST-1	Underground Aluminum Service 4/0 + 2/0 Neutral from pad mounted transformer	385	146	Overhead	C1PO	GS1	\$ 12.97	56,210	\$ 729,044
C350TRANSST-1	Underground Aluminum Service 350 + 4/0 Neutral from pad mounted transformer	235	165	Overhead	C1PO	GS1	\$ 14.06	38,775	\$ 545,177
C1-0TRANSST-1	Underground Aluminum Service 1/0 + #2 Neutral from pad mounted transformer	165	125	Overhead	C1PO	GS1	\$ 12.10	20,625	\$ 249,563
C500TRANSST-1	Underground Aluminum Service 500 + 350 Neutral from pad mounted transformer	70	135	Overhead	C1PO	GS1	\$ 15.49	9,450	\$ 146,381
C1-0TX-FTST-1	Overhead 1/0 Triplex from pole	45	105	Overhead	C1PO	GS1	\$ 12.12	4,725	\$ 57,267
C4-0TX-FTST-1	Overhead 4/0 Triplex from pole	15	100	Overhead	C1PO	GS1	\$ 12.87	1,500	\$ 19,305
CTX4-0ALST-1	Underground 4/0 Triplex - Connected to overhead transformer	772	170	Underground	C1PU	GS1	\$ 12.97	131,240	\$ 1,702,183
CTX1-0ALST-1	UG SER TX-CBL+CONN-3C-2 1/0+2N	350	122	Underground	C1PU	GS1	\$ 12.10	42,700	\$ 516,670
CTX350ALST-1	UG SER TX-CBL+CONN-3C-2 350+4/0N	272	194	Underground	C1PU	GS1	\$ 14.06	52,768	\$ 741,918
CTX500ALST-1	UG SER TX-CBL+CONN-3C-2 500+350N	70	213	Underground	C1PU	GS1	\$ 15.49	14,910	\$ 230,956
CTX750ALST-1	UG SER TX-CBL+CONN-3C-2 750+500N	44	201	Underground	C1PU	GS1	\$ 16.34	8,844	\$ 144,511
CTX2-350ALST-1	UG SER TX-CBL+CONN-2 3C-350+4/0N	7	147	Underground	C1PU	GS1	\$ 17.16	1,029	\$ 17,658
C4-0QX-FTST-1	Overhead 4-0 Quadplex from pole	107	66	Overhead	C3PO	GS3	\$ 13.56	7,062	\$ 95,761
C2-4-0QX-FTST-1	Overhead 4-0 Quadplex from pole - 2 sets	32	67	Overhead	C3PO	GS3	\$ 16.16	2,144	\$ 34,647
4CC750AL	Underground 750 kcmil Quad - 1 SET	278	159	Underground	C3PU	GS3	\$ 20.33	44,202	\$ 898,627
4CC750AL-3	Underground 750 kcmil Quad - 3 SET	225	170	Underground	C3PU	GS3	\$ 37.80	38,250	\$ 1,445,850
4CC750AL-4	Underground 750 kcmil Quad - 4 SET	95	200	Underground	C3PU	GS3	\$ 46.64	19,000	\$ 886,160
4CC750AL-6	Underground 750 kcmil Quad - 6 SET	90	140	Underground	C3PU	GS3	\$ 65.75	12,600	\$ 828,450
4CC750AL-5	Underground 750 kcmil Quad - 5 SET	85	125	Underground	C3PU	GS3	\$ 55.34	10,625	\$ 587,988
4CC750AL-7	Underground 750 kcmil Quad - 7 SET	75	115	Underground	C3PU	GS3	\$ 73.12	8,625	\$ 630,660
4CC4-0AL	Underground 4/0 Quad	60	180	Underground	C3PU	GS3	\$ 15.32	10,800	\$ 165,456
4CC500CUS-6	Underground Copper 500 kcmil Quad 6 SET	25	105	Underground	C3PU	GS3	\$ 190.81	2,625	\$ 500,876
4CC500CUS	Underground Copper 500 kcmil Quad 1 SET	20	100	Underground	C3PU	GS3	\$ 41.17	2,000	\$ 82,340
4CC500CUS-3	Underground Copper 500 kcmil Quad 3 SET	15	120	Underground	C3PU	GS3	\$ 100.33	1,800	\$ 180,594
4CC500CUS-4	Underground Copper 500 kcmil Quad 4 SET	10	110	Underground	C3PU	GS3	\$ 130.01	1,100	\$ 143,011
4CC500CUS-2	Underground Copper 500 kcmil Quad 2 SET	5	85	Underground	C3PU	GS3	\$ 70.65	425	\$ 30,026

Wire Type	Description	Installed Cost (\$/ft)	Cost / 100'
C4-0TRANSST-1	Underground Aluminum Service 4/0 + 2/0 Neutral from pad mounted transformer	\$ 12.97	\$ 1,297.00
C1-0TRANSST-1	Underground Aluminum Service 1/0 + #2 Neutral from pad mounted transformer	\$ 12.10	\$ 1,210.00
C350TRANSST-1	Underground Aluminum Service 350 + 4/0 Neutral from pad mounted transformer	\$ 14.06	\$ 1,406.00
C500TRANSST-1	Underground Aluminum Service 500 + 350 Neutral from pad mounted transformer	\$ 15.49	\$ 1,549.00
C1-0TX-FTST-1	Overhead 1/0 Triplex from pole	\$ 12.12	\$ 1,212.00
C4-0TX-FTST-1	Overhead 4/0 Triplex from pole	\$ 12.87	\$ 1,287.00
CTX4-0ALST-1	Underground 4/0 Triplex - Connected to overhead transformer	\$ 12.97	\$ 1,297.00
C4-0QX-FTST-1	Overhead 4-0 Quadplex from pole	\$ 13.56	\$ 1,356.00
C2-4-0QX-FTST-1	Overhead 4-0 Quadplex from pole - 2 sets	\$ 16.16	\$ 1,616.00
4CC750AL	Underground 750 kcmil Quad - 1 SET	\$ 20.33	\$ 2,033.00
4CC750AL-3	Underground 750 kcmil Quad - 3 SET	\$ 37.80	\$ 3,780.00
4CC750AL-4	Underground 750 kcmil Quad - 4 SET	\$ 46.64	\$ 4,664.00
4CC750AL-6	Underground 750 kcmil Quad - 6 SET	\$ 65.75	\$ 6,575.00
4CC750AL-5	Underground 750 kcmil Quad - 5 SET	\$ 55.34	\$ 5,534.00
4CC750AL-7	Underground 750 kcmil Quad - 7 SET	\$ 73.12	\$ 7,312.00
4CC4-0AL	Underground 4/0 Quad	\$ 15.32	\$ 1,532.00
4CC500CUS-6	Underground Copper 500 kcmil Quad 6 SET	\$ 190.81	\$ 19,081.00
4CC500CUS	Underground Copper 500 kcmil Quad 1 SET	\$ 41.17	\$ 4,117.00
4CC500CUS-3	Underground Copper 500 kcmil Quad 3 SET	\$ 100.33	\$ 10,033.00
4CC500CUS-4	Underground Copper 500 kcmil Quad 4 SET	\$ 130.01	\$ 13,001.00
4CC500CUS-2	Underground Copper 500 kcmil Quad 2 SET	\$ 70.65	\$ 7,065.00
CTX1-0ALST-1	UG SER TX-CBL+CONN-3C-2 1/0+#2N	\$ 12.10	\$ 1,210.00
CTX350ALST-1	UG SER TX-CBL+CONN-3C-2 350+4/0N	\$ 14.06	\$ 1,406.00
CTX500ALST-1	UG SER TX-CBL+CONN-3C-2-500+350N	\$ 15.49	\$ 1,549.00
CTX750ALST-1	UG SER TX-CBL+CONN-3C-2-750+500N	\$ 16.34	\$ 1,634.00
CTX2-350ALST-1	UG SER TX-CBL+CONN-2 3C-350+4/0N	\$ 17.16	\$ 1,716.00
C4TX-FTST-1	OH SER-4 TRIPLEX FROM POLE	\$ 11.50	\$ 1,150.00

		Current Base Rate Revenues			Index Rate of Return	
		OCA I-1 (SUPPLEMENTAL)	Service Correction (OSBA II-2)	Difference	OCA I-1 (SUPPLEMENTAL)	Service Correction (OSBA II-2)
Residential	RS	\$722,478,068	\$722,478,068	\$0	0.97	0.99
Residential-Thermal Storage	RTS	\$7,975,047	\$7,975,047	\$0	0.47	0.48
Small General Service - Sec. Voltage	GS-1	\$78,788,843	\$78,788,843	\$0	0.89	0.79
Large General Service - Sec. Voltage	GS-3	\$129,227,939	\$129,227,939	\$0	1.23	1.20
Large General Service - 12 KV	LP-4	\$38,995,732	\$38,995,732	\$0	0.81	0.81
Large General Service - 69 KV or Higher	LP-5	\$1,980,696	\$1,980,696	\$0	5.96	5.96
Separate Meter General Space Heating Service	GH-2	\$1,307,020	\$1,307,020	\$0	1.02	0.96
Street Lighting/Area Lighting	SL/AL	\$24,465,816	\$24,465,816	\$0	1.43	1.43
System		\$1,005,219,161	\$1,005,219,161	\$0	1.00	1.00

		ACOSS - Proposed Base Rate Revenues			Mitigated - Proposed Base Rate Revenues		
		OCA I-1 (SUPPLEMENTAL)	Service Correction (OSBA II-2)	Difference	OCA I-1 (SUPPLEMENTAL)	Service Correction (OSBA II-2)	Difference
Residential	RS	\$996,896,465	\$991,430,580	-\$5,465,884	\$1,000,028,588	\$994,644,472	-\$5,384,117
Residential-Thermal Storage	RTS	\$13,734,067	\$13,685,456	-\$48,611	\$12,510,013	\$12,509,942	-\$72
Small General Service - Sec. Voltage	GS-1	\$110,517,597	\$113,998,154	\$3,480,557	\$110,820,313	\$114,223,319	\$3,403,005
Large General Service - Sec. Voltage	GS-3	\$174,539,344	\$176,538,407	\$1,999,063	\$175,180,913	\$177,130,246	\$1,949,333
Large General Service - 12 KV	LP-4	\$64,812,768	\$64,812,768	\$0	\$61,170,438	\$61,170,088	-\$351
Large General Service - 69 KV or Higher	LP-5	\$1,364,702	\$1,364,702	\$0	\$1,980,696	\$1,980,696	\$0
Separate Meter General Space Heating Service	GH-2	\$1,823,155	\$1,858,029	\$34,875	\$1,828,397	\$1,862,470	\$34,073
Street Lighting/Area Lighting	SL/AL	\$30,851,168	\$30,851,168	\$0	\$31,019,906	\$31,018,034	-\$1,872
System		\$1,394,539,265	\$1,394,539,265	\$0	\$1,394,539,265	\$1,394,539,265	\$0

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
STEVEN W. WISHART
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Affordability**
 Rate Design
 Standby Service

Dated: January 23, 2026

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Steven W. Wishart. I am an Assistant Vice President with Concentric Energy Advisors, Inc. (“Concentric”). My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Did you previously submit testimony in this proceeding?

A. Yes, I previously submitted rebuttal testimony on behalf of PPL Electric Utilities Corporation (“PPL Electric,” “PPL,” or the “Company”), which was marked as PPL Electric Statement No. 8.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to specific issues raised by intervenors regarding PPL Electric’s proposed rate design, including claims related to affordability, residential customer charges, Universal Service Rider (“USR”) cost allocation, the elimination of Rate Schedule RTS, and the design of certain non-residential rates.

In this testimony, I clarify the factual and analytical record where intervenor testimony mischaracterizes the magnitude or effects of the Company’s proposed rates, and I explain why PPL Electric’s proposed rate design remains reasonable, consistent with cost-of-service principles, and aligned with long-standing Commission ratemaking practices.

In addition, this rebuttal testimony reflects the Company’s updated revenue requirement presented in rebuttal by other Company witnesses. Using the same rate design

1 framework and methodology applied in my direct testimony, I update the resulting bill
2 impacts and revenue impacts to reflect those revisions, without independently recalculating
3 the Company's revenue requirement.

4
5 **Q. How is your testimony organized?**

6 A. My testimony proceeds as follows:

7 **Section II** addresses the affordability framework and bill impact issues raised by
8 intervenors, including claims regarding the overall magnitude and drivers of residential and
9 low-income customer bill impacts.

10 **Section III** addresses other parties' testimony regarding the proposed residential fixed
11 monthly customer charge, including claims related to affordability, conservation
12 incentives, and the alleged regressive nature of fixed charges.

13 **Section IV** addresses the elimination of Rate Schedule RTS and the proposed transition of
14 RTS customers to Rate Schedule RS.

15 **Section V** addresses other parties' proposals and testimony regarding the Universal Service
16 Rider ("USR"), including claims that USR costs should be expanded or reallocated to
17 additional customer classes.

18 **Section VI** addresses issues raised regarding the Rate GS-3 rate design, including
19 testimony submitted by Walmart Inc. ("Walmart")

20 **Section VII** addresses issues related to large load customers, including proposed rate
21 structures and cost-allocation considerations raised by intervenors.

1 **Section VIII** addresses issues related to the proposed Electric Vehicle (“EV”) DC Fast
2 Charging (“DCFC”) rate.

3 **Section IX** addresses proposed changes to Rule 6 governing auxiliary and standby service
4 for customers with on-site generation.

5 **Section X** addresses updates to rate impacts reflecting the Company’s revised revenue
6 requirement presented in rebuttal.

7
8 **Q. Are you sponsoring any exhibits with your rebuttal testimony?**

9 A. Yes, I am sponsoring PPL Electric Exhibit SWW-1R, which presents updated rates
10 proposed by the Company as well as bill impacts for each rate class. I am also sponsoring
11 PPL Electric Exhibits SWW-2R and SWW-3R, which are updates to Exhibit Regs. § 53.53
12 parts IV-C and IV-D respectively.

13
14 **II. AFFORDABILITY FRAMEWORK AND BILL IMPACTS**

15 **Q. What affordability concerns have been raised by other parties in this proceeding?**

16 A. Multiple intervenors raise concerns regarding the affordability of electric service for
17 residential and low-income customers, though they do so from differing perspectives and
18 with differing proposed remedies.

19 Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania
20 (“CAUSE-PA”) witness Patrick Cicero argues that PPL’s proposed residential rate design,
21 including increases to the fixed monthly customer charge and the transition of customers

1 from Rate RTS to Rate RS, would disproportionately impact low-income customers and
2 undermine the effectiveness of low-income assistance programs. Mr. Cicero further
3 contends that a substantial portion of PPL’s requested revenue increase is functionally
4 borne by low-income households and recommends modifications to rate design and the
5 allocation of Universal Service Rider (“USR”) costs to mitigate those impacts.¹

6 Office of Consumer Advocate (“OCA”) witness Roger Colton similarly asserts that
7 PPL’s proposed rate design would exacerbate affordability challenges for residential
8 customers and recommends the creation of new, non-bypassable charges on large load
9 customers to offset what he characterizes as increased universal service costs associated
10 with data center development. Mr. Colton further claims a direct causal relationship
11 between large load growth and the need for increased universal service funding.²

12 Energy Justice Advocates (“EJA”) witness Karl Rabago raises concerns regarding
13 the proposed increase in the residential customer charge and argues that higher fixed
14 charges are regressive and inconsistent with affordability and economic efficiency
15 principles. Mr. Rabago recommends both a lower residential customer charge and the
16 expansion of USR cost recovery to non-residential customers, including large load
17 customers.³

18 In addition, CEO witness Jennifer Warabak expresses concern that increases in
19 fixed customer charges reduce low-income customers’ ability to manage their bills and

¹ CAUSE-PA Statement No. 1, pp. 22–32, 48, 85–97.

² OCA Statement 8, pp. 6, 87–98.

³ EJA Statement No. 1, pp. 6, 17–18, 31–45.

1 asserts that the Commission should not approve rate increases without a corresponding
2 increase in funding for universal service programs.⁴

3 Collectively, these witnesses frame affordability concerns around residential rate
4 design, fixed customer charges, the treatment of low-income customers, and the
5 appropriate scope and funding of universal service programs, while offering differing
6 views as to the causes of affordability challenges and the appropriate regulatory responses.

7
8 **Q. Based on your review of the record, how should the affordability implications of the**
9 **proposed distribution rate changes be evaluated?**

10 A. Based on my review of the record and my analysis of long-term electricity price trends,
11 household energy burden, and consumer expenditure data, the proposed distribution rate
12 changes represent a modest adjustment to one component of the overall electric bill and
13 should be evaluated in the context of broader household spending trends.

14 As discussed below, electric distribution charges account for a limited share of
15 customer bills, have remained relatively stable over time, and are well below national
16 benchmarks. In addition, long-term data show that electricity expenditures represent a
17 relatively small portion of total household spending and have grown more slowly than other
18 essential cost categories such as housing, transportation, food, and health care.

19 In my professional judgment, when considered in this broader context, the
20 affordability concerns raised by some intervenors are not commensurate with the

⁴ CEO Statement No. 1, pp. 4–6.

1 magnitude of the changes at issue and do not support fundamental changes to rate design
2 or cost recovery mechanisms.

3
4 **Q. Why is it important to distinguish between total bill impacts and the distribution rates**
5 **at issue in this proceeding when evaluating affordability?**

6 A. Customers experience affordability at the level of the total electric bill, but this proceeding
7 addresses only PPL Electric's distribution rates. Recent increases in customer bills have
8 been driven largely by generation-related charges established through PJM wholesale
9 markets, which are outside the Company's control. Both generation-related and
10 transmission-related charges are outside the scope of this case as discussed in other PPL
11 Electric rebuttal testimony. As a result, changes to distribution rates represent only one
12 component of overall bill impacts. Based on the Company's proposed Residential rates, the
13 distribution component, which PPL Electric can propose to change subject to the approval
14 of the Pennsylvania Public Utility Commission ("PUC" or the "Commission"), represents
15 only 35 percent of the average customer's monthly bill. Evaluating affordability without
16 distinguishing between distribution charges and other bill components can attribute the
17 forces driving higher bills to the wrong causes and lead to decisions that do not address the
18 underlying cost drivers.

1 **Q. How have PPL Electric's distribution rates trended over time, and how do they**
2 **compare to national benchmarks?**

3 A. As discussed in my direct testimony, PPL Electric's residential distribution rates have
4 remained relatively stable over the past decade and have grown at a much slower pace than
5 overall customer bills. Based on publicly available data, PPL Electric's average residential
6 delivery rates increased at an average annual rate of approximately 0.6 percent between
7 2016 and 2024 and, when adjusted for inflation, have declined over that period.

8 In addition, PPL Electric's residential delivery rates are substantially below the
9 national average. Over time, the gap between PPL Electric's delivery rates and the national
10 average has widened, such that PPL Electric's delivery rates remain well below national
11 benchmarks even before consideration of the Company's proposed increases in this
12 proceeding. These trends provide important context for evaluating affordability concerns
13 related specifically to distribution rates.⁵
14

15 **Q. How has the inflation-adjusted cost of electricity in the United States changed over**
16 **time?**

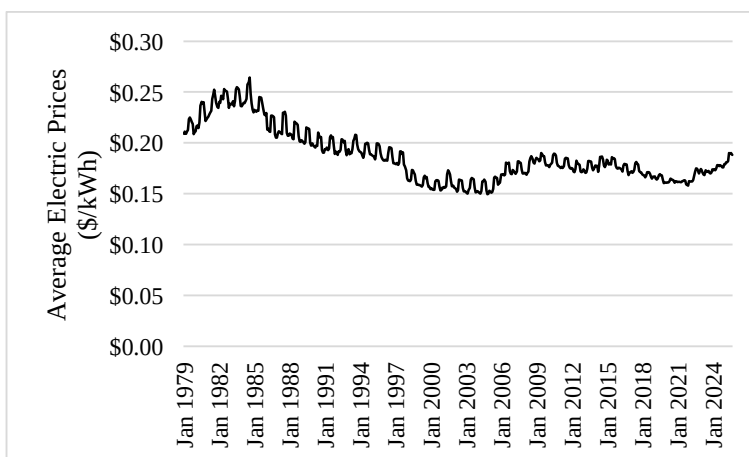
17 A. As discussed in my direct testimony, long-term data show that the real, inflation-adjusted
18 cost of electricity in the United States has declined substantially over time. Although
19 customers have experienced increases in recent years, particularly driven by wholesale

⁵ PPL Electric Statement No. 8, pp. 8–10.

market conditions, the real price of electricity today remains approximately 20 percent lower than its peak in the early 1980s.

Figure 1 presents the inflation-adjusted average U.S. price of electricity from 1978 through 2025. The data are derived from the U.S. Bureau of Labor Statistics (“BLS”) electricity price series, adjusted using the Consumer Price Index. The figure shows that electricity prices peaked around 1980 and declined steadily in real terms for several decades thereafter. While recent increases are evident, current prices remain well below historical peak levels.⁶

Figure 1 – U.S. Inflation Adjusted Average Price of Electricity



⁶ The inflation-adjusted price of electricity was calculated by the witness using publicly available data from the U.S. Bureau of Labor Statistics (“BLS”). Nominal average U.S. electricity prices are from the BLS Average Price of Electricity per Kilowatt-Hour for U.S. City Average series (Series ID: APU000072610), as published by the Federal Reserve Bank of St. Louis FRED database. Inflation adjustments were performed using the BLS Consumer Price Index for All Urban Consumers (“CPI-U”), All Items, U.S. City Average (Series ID: CUUR0000SA0), with prices converted to constant dollars using the CPI-U annual average values.

Q. What do long-term trends in household energy burden indicate about affordability?

A. Long-term trends in household energy burden show a similar pattern. Energy burden, commonly defined as the share of household income spent on electricity and natural gas service, peaked around 1980, when energy prices rose sharply relative to household income, and has declined significantly since that time.

Figure 2 shows average U.S. household energy burden from 1959 through 2024, based on Federal Reserve Economic Data (“FRED”) national income data and historical electricity and natural gas expenditures. Despite periodic volatility, including increases in recent years, average household energy burden today remains well below historical peak levels, indicating that growth in household income has outpaced growth in energy costs over the long term.

Figure 2 – U.S. Average Energy Burden



Q. How does spending on electricity compare to other essential household expenses?

A. Data from the BLS Consumer Expenditure Survey (“CES”) show that electricity represents a relatively small share of total household expenditures compared to other essential categories such as housing, transportation, food, and health care.

Table 1 illustrates the average share of household expenditures by major category using CES data for consumer units in the lowest 10 percent income decile, which is used here to reflect the spending patterns most relevant to low-income households. As shown, electricity accounts for a modest portion of total household spending relative to housing, food, transportation, and health care. This comparison provides important context for evaluating claims that electricity costs are a primary driver of household affordability challenges.

Table 1 – Household Spending, Lowest 10 Percent Income Decile

Housing	\$12,114	62.0%
Food	\$5,311	27.2%
Transportation	\$4,341	22.2%
Healthcare	\$2,755	14.1%
Electricity	\$1,181	6.0%

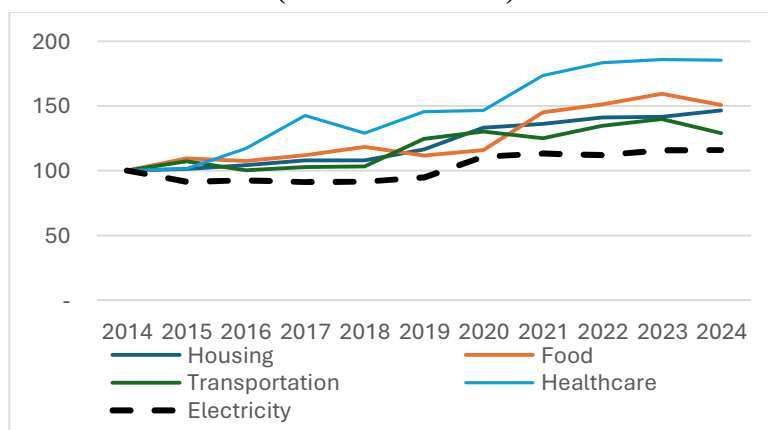
Q. How have electricity costs grown over time relative to other essential household expenses?

A. In addition to representing a smaller share of household expenditures, electricity costs have grown more slowly over time than many other essential household expense categories.

Figure 3 presents indexed expenditure trends for electricity, housing, transportation, food, and health care based on CES data for consumer units in the lowest 10 percent income decile, with all categories normalized to a common base year. As shown, expenditures on housing, health care, and transportation have increased at substantially faster rates than electricity over time. While electricity costs have risen in nominal terms, the growth has been comparatively modest relative to other necessities.

Taken together, these data indicate that broader cost-of-living pressures faced by low-income households are driven primarily by non-electric expenses, and that electricity costs, while important, are not the dominant contributor to long-term affordability challenges.⁷

**Figure 3 – Growth in Household Spending Categories,
Lowest 10 Percent Income Decile**
(2014 Indexed to 100)



⁷ Household expenditure shares and growth trends were calculated by the witness using data from the U.S. Bureau of Labor Statistics' Consumer Expenditure Survey ("CES"). Expenditure data reflect calendar-year average spending by consumer units in the lowest income decile, based on income before taxes, as published in the CES demographic tables. This income group was selected to reflect the spending patterns most relevant to low-income households.

1 **III. RESIDENTIAL FIXED MONTHLY CUSTOMER CHARGE**

2 **Q. What concerns have other parties raised regarding the proposed residential fixed**
3 **monthly customer charge?**

4 A. Several intervenors raise concerns regarding PPL Electric's proposed residential fixed
5 monthly customer charge. CAUSE-PA witness Patrick Cicero, EJA witness Karl Rabago,
6 and CEO witness Jennifer Warabak generally argue that higher fixed charges reduce
7 customers' ability to control their bills through conservation and disproportionately affect
8 low-income customers.⁸ These witnesses also characterize the proposed increase in the
9 residential customer charge as significant when compared to the current tariffed charge.

10 OCA witness Roger Colton similarly criticizes the proposed customer charge,
11 asserting that fixed charges undermine affordability and conservation and should be offset
12 through greater reliance on volumetric charges or additional charges assessed to large load
13 customers.⁹ Collectively, these witnesses frame the customer charge primarily as an
14 affordability and behavioral issue, rather than in terms of its magnitude within the overall
15 bill or its relationship to underlying cost recovery.

16
17 **Q. Have any parties supported the proposed residential customer charge?**

18 A. Yes. I&E witness Ethan Cline supports the Company's proposed residential customer
19 charge, explaining that it reasonably reflects customer-related costs and represents an

⁸ CAUSE-PA Statement No. 1, pp. 25–33; EJA Statement No. 1, pp. 42–46; CEO Statement No. 1, pp. 4–12.

⁹ OCA Statement 8, pp. 87–98, particularly pp. 95–96.

1 appropriate balance between fixed and volumetric recovery.¹⁰ Mr. Cline further notes that
2 the proposed customer charge is consistent with accepted ratemaking principles and is not
3 excessive when evaluated in the context of the overall residential rate design.
4

5 **Q. Are arguments regarding minimum system studies addressed in this section?**

6 A. No. I do not address arguments regarding the use of minimum system studies in the
7 Company's cost-of-service analysis. Those issues are addressed separately by the
8 testimony of PPL Electric witness Bickey Rimal.
9

10 **Q. Is the proposed residential customer charge a 20 percent increase, as some intervenors**
11 **suggest?**

12 A. No. Several intervenors characterize the proposed residential customer charge as an
13 increase of approximately 20 percent, but that characterization is based on an incomplete
14 comparison that excludes existing riders and surcharges currently recovered outside base
15 rates.

16 Specifically, CAUSE-PA witness Patrick Cicero and OCA witness Clarence
17 Johnson describe the proposed increase by comparing the proposed \$17.00 customer
18 charge to the current base customer charge of \$14.09, which excludes the SMR-2, DSIC,
19 and other applicable riders.¹¹ Using that narrow comparison, these witnesses assert that the
20 proposal represents an increase of approximately 20 percent.

¹⁰ I&E Statement No. 4, pp. 6–8.

¹¹ CAUSE-PA Statement No. 1, pp. 7–8; OCA Statement 4, p. 31.

When the existing riders that are being rolled into base rates in this proceeding are properly accounted for, the effective residential customer charge increases from approximately \$15.49 per month to \$17.00 per month, representing an increase of approximately 9.1 percent, not 20 percent. Table III-1 illustrates the current and proposed customer charge with and without riders and demonstrates that the intervenors' characterization materially overstates the magnitude of the proposed change.

Correctly accounting for the roll-in of existing riders is necessary to evaluate the actual customer experience and to assess the reasonableness of the proposed residential customer charge. The following table presents the change in the customer and volumetric charge based on the updated revenue requirements and cost allocation that I discuss at the end of my testimony.

Table 2 – Current and Proposed Residential Customer Charge

	Current Rates	Proposed Rates	Change
Customer Charge	\$15.58/Bill	\$17.00/Bill	9.1%
Energy Charge	\$0.05049/kW	\$0.05102/kWh	44.4%

Q. How significant is the residential customer charge within a typical residential customer's bill?

A. The residential customer charge represents a relatively small portion of a typical residential customer's total electric bill. For an average residential customer, the proposed \$17.00 monthly customer charge accounts for approximately 8.9 percent of the total bill. The remaining portion of the bill reflects volumetric distribution charges, riders, and energy supply costs.

1 Given its limited share of the total bill, changes to the residential customer charge
2 cannot reasonably be characterized as a primary driver of affordability outcomes,
3 particularly when compared to other bill components that vary substantially with usage and
4 wholesale market conditions.

5
6 **Q. Would reducing the residential customer charge meaningfully increase customers’**
7 **ability to control their bills through conservation?**

8 A. No. Multiple witnesses, including Mr. Cicero and Mr. Rabago, argue that reducing the
9 residential customer charge and shifting recovery to volumetric charges would materially
10 enhance customers’ ability to manage their bills through conservation.¹²

11 However, the actual impact of reducing the customer charge would be very small.
12 Table 3 compares the monthly bill for an average residential customer under the proposed
13 \$17.00 customer charge and under a hypothetical \$10.00 customer charge, which is lower
14 than any customer charge proposed by any party in this proceeding. Because rates are
15 designed to hit a specific revenue target, the monthly bill is the same for the average
16 customer with 918kWh of monthly usage. The table then illustrates the impact of a 25
17 percent reduction in usage, reflecting a substantial conservation investment.

18 Table 3 illustrates that the difference in monthly bill savings, from the hypothetical
19 conservation investment, between the proposed \$17.00 charge and the hypothetical \$10.00
20 charge is approximately \$1.75 per month, or 4.0 percent. This demonstrates that the

¹² CAUSE-PA Statement No. 1, p. 10; EJA Statement No. 1, pp. 42–43.

incremental bill-control benefits associated with reducing the customer charge are limited when the customer charge represents a small share of the overall bill.

Table 3 – Impact of Lower Customer Charge on Conservation

	Proposed Rates	Hypothetical Rates
Customer Charge	\$17.00/Bill	\$10.00/Bill
Energy Charge	\$0.05102/kWh	\$0.05864/kWh
ACR 4	\$0.00220/kWh	\$0.00220/kWh
USR	\$0.01111/kWh	\$0.01111/kWh
GSC-1	\$0.09166/kWh	\$0.09166/kWh
TSC	\$0.03324/kWh	\$0.03324/kWh

Baseline Volume	918 kWh	
Customer Charge	\$17.00	\$10.00
<u>Energy Charge</u>	<u>\$46.82</u>	<u>\$53.82</u>
Base Rate Subtotal	\$63.82	\$63.82
<u>Distribution Riders</u>	<u>\$12.21</u>	<u>\$12.21</u>
Total Distribution	\$76.04	\$76.03
<u>Energy Supply</u>	<u>\$114.62</u>	<u>\$114.62</u>
Total Bill	\$190.66	\$190.65

25% Reduced Vol.	688 kWh	
Customer Charge	\$17.00	\$10.00
<u>Energy Charge</u>	<u>\$35.12</u>	<u>\$40.36</u>
Base Rate Subtotal	\$52.12	\$50.36
<u>Distribution Riders</u>	<u>\$9.16</u>	<u>\$9.16</u>
Total Distribution	\$61.28	\$59.52
<u>Energy Supply</u>	<u>\$85.97</u>	<u>\$85.97</u>
Total Bill	\$147.25	\$145.49

Monthly Savings	-\$43.42	-\$45.16
Change In Monthly Savings	-\$1.75	4.0%

1 **Q. How should claims regarding economically efficient price signals be evaluated in this**
2 **context?**

3 A. Some witnesses, including Mr. Rabago, assert that increasing reliance on volumetric
4 charges produces more economically efficient price signals by encouraging conservation.¹³
5 From an economic perspective, however, an efficient price signal exists when variable
6 charges reflect the marginal system cost savings associated with reduced usage.

7 If volumetric charges exceed marginal system costs, customers receive bill savings
8 that exceed the system cost reductions actually realized. The resulting revenue shortfall
9 must then be recovered from other customers in future rate proceeding, creating cross-
10 subsidies rather than improving economic efficiency. Accordingly, increasing volumetric
11 charges beyond marginal cost does not necessarily improve efficiency and may instead
12 distort cost recovery over time.

13
14 **Q. Are low-income customers necessarily low-usage customers?**

15 A. No. Discovery responses in this proceeding demonstrate that low-income customers are
16 not synonymous with low-usage customers. Data provided by PPL Electric in response to
17 CAUSE-PA's discovery show that confirmed low-income customers, including CAP
18 participants, generally use as much electricity as, and often more electricity than, the

¹³ EJA Statement No. 1, pp. 35–36, 42–43.

1 average residential customer, for both electric-heating and non-electric-heating
2 households.¹⁴

3 This point is also acknowledged by Sustainable Energy Fund (“SEF”) witness John
4 M. Costlow, who recognizes that many low-income customers, particularly those with
5 electric heat or older housing stock, have higher electricity usage.¹⁵ As a result,
6 affordability challenges for low-income customers are driven primarily by income and
7 housing characteristics, not by unusually low consumption levels. This undermines the
8 assumption that reducing fixed charges inherently provides targeted affordability benefits
9 to low-income households.

10
11 **Q. What conclusions can be drawn regarding the proposed residential customer**
12 **charge?**

13 A. When evaluated in context, the proposed residential customer charge represents a modest
14 and reasonable adjustment. The charge constitutes a small portion of the overall bill, does
15 not materially limit customers’ ability to manage usage, and does not drive affordability
16 outcomes in the manner suggested by intervenors.

17 Moreover, claims that reducing the customer charge would materially improve
18 conservation outcomes or affordability are not supported by quantitative evidence. For

¹⁴ See the Response to Interrogatory CAUSE-PA I-20 and its Attachment 1, which are attached to PPL Electric Witness Norden’s rebuttal testimony as PPL Electric Exhibit LN-12R.

¹⁵ SEF Statement No. 1, pp. 20–22.

these reasons, the proposed residential customer charge is reasonable and consistent with sound rate design principles.

IV. ELIMINATION OF RATE SCHEDULE RTS AND TRANSFER TO RATE SCHEDULE RS

Q. What is PPL Electric's proposal with respect to Rate Schedule RTS, and which parties addressed this issue?

A. PPL Electric proposes to eliminate Rate Schedule RTS, Residential Thermal Service, and transition existing RTS customers to Rate Schedule RS. Rate Schedule RTS has been closed to new customers since 1995 and currently applies only to a limited and declining population of legacy customers.

Certain parties addressed this proposal in their testimony. CAUSE-PA witness Patrick Cicero and OCA witness Roger Colton oppose elimination of RTS, primarily citing customer bill impact concerns.¹⁶ No party asserts that RTS customers continue to receive distinct load management services that would justify maintaining RTS as a separate rate schedule.

Q. What was the original basis for maintaining a separate RTS rate schedule?

A. Rate Schedule RTS was originally designed to serve residential customers with electric thermal storage systems that provided load management benefits. The RTS tariff expressly

¹⁶ CAUSE-PA Statement No. 1, pp. 34-36; OCA Statement 8, pp. 101-103.

1 conditions eligibility on the existence of load management capabilities, defined as the
2 positive automatic control of thermal storage systems that limit on-peak electric usage.¹⁷
3

4 **Q. How do bill impact considerations factor into the proposal to eliminate RTS?**

5 A. Opposition to eliminating RTS focuses primarily on customer bill impacts. Mr. Cicero and
6 Mr. Colton argue that transferring RTS customers to Rate Schedule RS would result in
7 higher distribution bill increases for RTS customers than for customers currently taking
8 service under Rate Schedule RS.¹⁸

9 It is important, however, to distinguish between the incremental impact of moving
10 RTS customers to RS and the bill impacts RTS customers would experience even if RTS
11 were retained as a separate rate schedule.

12 Based on my analysis, moving RTS customers to Rate Schedule RS results in an
13 increase in total distribution charges of approximately 45.1 percent. If RTS were instead
14 retained as a separate rate class, RTS customers would still experience an increase of
15 approximately 30.8 percent, which is materially higher than the 21.5 percent increase
16 experienced by RS customers.

17 Accordingly, while the bill impact associated with transferring RTS customers to
18 RS is larger than the increase that would occur if RTS were retained, RTS customers would
19 face significantly higher distribution rate increases than RS customers under either
20 outcome. Retaining RTS would moderate, but not eliminate, the differential in bill impacts.

¹⁷ PPL Electric Tariff, Rate Schedule RTS, Electric Pa. P.U.C. No. 201, Revised Page Nos. 21 and 21A.

¹⁸ CAUSE-PA Statement No. 1, pp. 34-36; OCA Statement 8, pp. 101-103.

Table 4 – Change in Average Bills

	RS		Migrate RTS to RS	Continue RTS as Stand- Alone Schedule
Base Rates	\$17.30 37.2%	\$41.60 69.0%		\$29.45 48.8%
Total Distribution	\$13.48 21.5%	\$38.53 45.1%		\$26.38 30.8%
Total Bill	\$13.65 7.7%	\$38.77 13.2%		\$26.62 9.1%

Q. Do bill impact differences justify maintaining RTS as a separate rate schedule?

A. In my professional judgment, bill impact differences alone do not justify maintaining a separate residential rate schedule where the original justification for that schedule no longer exists. RTS is a legacy tariff that has been closed to new customers for nearly three decades and no longer reflects distinct service characteristics or system benefits.

Preserving RTS solely to mitigate bill impacts would maintain a rate structure that lacks a current operational or cost-based rationale and would perpetuate administrative complexity associated with serving a shrinking customer population.

Q. What conclusions can be drawn regarding the proposal to eliminate RTS?

A. Rate Schedule RTS no longer serves a distinct operational purpose and does not reflect materially different service characteristics from those of Rate Schedule RS. While RTS customers experience higher bill impacts than RS customers under the proposed rate changes, that outcome would occur even if RTS were retained as a separate rate schedule.

1 Eliminating RTS and transitioning customers to Rate Schedule RS is reasonable,
2 simplifies residential rate design, and aligns rate treatment with current service conditions.

3
4 **V. UNIVERSAL SERVICE RIDER (USR)**

5 **Q. What issues regarding the USR have been raised by other parties in this proceeding?**

6 **A.** Several intervenors raise issues regarding the scope and application of the USR. While
7 some witnesses raise concerns regarding the adequacy of universal service support, other
8 parties propose expanding USR cost recovery beyond residential customers to include
9 additional non-residential customer classes, including large commercial and industrial
10 customers.

11 The USR is a program-specific rider designed to recover the costs of low-income
12 assistance and universal service programs that are available exclusively to residential
13 customers. Consistent with that design, USR costs are primarily recovered from residential
14 customers under PPL Electric's tariff. The tariff also applies USR charges to certain limited
15 non-residential customer categories, including service to volunteer fire companies, non-
16 profit senior citizen centers, non-profit rescue squads, and non-profit ambulance services
17 served under specified GS-1 and GS-3 sub-schedules.

18 Although I do not address the appropriate level of USR funding in this testimony, I
19 did review PPL Electric's 2025 Universal Service Rider Reconciliation Report. That report
20 indicates that total 2025 universal service program expenditures were approximately \$136
21 million. For context, this level of spending is on the order of two-thirds of total distribution

1 operation and maintenance expenses reflected elsewhere in this proceeding, which is
2 notable given the targeted purpose of the USR and reinforces the importance of carefully
3 defining who should bear responsibility for these costs.¹⁹

4 Certain intervenors nonetheless propose expanding the USR to other customer
5 classes based on claims regarding system cost drivers and residential affordability
6 impacts.²⁰

7
8 **Q. Why do some intervenors propose expanding the USR to other customer classes?**

9 A. Intervenors proposing to expand the USR to additional customer classes generally argue
10 that large commercial and industrial customers contribute to increases in overall system
11 costs, including wholesale market costs, which in turn increase residential bills and energy
12 burdens. In particular, CAUSE-PA witness Patrick Cicero, OCA witness Roger Colton, and
13 EJA witness Karl R. Rabago each advance variations of this argument by asserting that
14 large customers, including high-load or data center customers, contribute to broader system
15 cost increases that ultimately affect residential customers. Based on this reasoning, these
16 witnesses assert that large customers should contribute to funding universal service
17 programs.²¹

¹⁹ PPL Electric Utilities Corporation, Universal Service Rider Reconciliation Report for the Period Ended December 31, 2025, Docket No. M-2025-3059311.

²⁰ CAUSE-PA Statement No. 1, pp. 37-40; OCA Statement 8, pp. 95-103.

²¹ CAUSE-PA Statement No. 1, pp. 38-40; OCA Statement 8, pp. 95-103; EJA Statement No. 1, pp. 48-50.

1 These arguments rely on an indirect chain of causation between large customer load
2 growth, wholesale market outcomes, and residential affordability rather than on direct
3 eligibility for universal service program benefits.

4
5 **Q. Is it appropriate to allocate USR costs based on claims regarding indirect bill impacts**
6 **or system-wide cost trends?**

7 A. In my professional judgment, allocating USR costs to non-residential customer classes
8 based solely on indirect bill impacts or system-wide cost trends is not appropriate, as the
9 USR is a targeted mechanism designed to fund specific residential assistance programs
10 rather than a general affordability surcharge. The Company's explanation regarding a
11 limited allocation of USR costs to the LP-6 rate class reflects a discrete policy
12 determination associated with the creation of a new rate class and Commission guidance
13 and is materially narrower than the broader reallocation of USR responsibility proposed by
14 intervenors.

15
16 **Q. What conclusions can be drawn regarding proposals to expand the USR to additional**
17 **customer classes?**

18 A. Broad proposals to expand the USR to additional customer classes are not supported by the
19 purpose or design of the universal service programs, traditional principles of cost
20 responsibility, or long-standing Pennsylvania electric utility practice. At the same time, the
21 Company's explanation regarding a limited allocation of USR costs to the LP-6 rate class
22 is materially narrower than the intervenor proposals addressed above.

1 Accordingly, while broader reallocation of USR costs remains unwarranted, the
2 Commission may evaluate the Company's proposed LP-6-specific USR allocation on its
3 own merits, consistent with applicable Commission guidance.

4
5 **VI. GS-3 RATE DESIGN**

6 **Q. What GS-3 rate design issues have been raised in this proceeding?**

7 A. The only party to raise concerns regarding the proposed GS-3 rate design is Walmart. No
8 other intervenor challenges the structure of the GS-3 rate or asserts that the proposed GS-
9 3 rate design is unreasonable for the class as a whole.²²

10 Walmart's testimony focuses on the bill impacts associated with the proposed GS-
11 3 distribution rate changes and asserts that those impacts are significant for its stores served
12 under GS-3.

13
14 **Q. How does Walmart characterize the impacts of the proposed GS-3 rate design?**

15 A. Walmart asserts that the proposed GS-3 rate design results in higher distribution charges
16 for its facilities and expresses concern regarding the magnitude of those increases. Walmart
17 characterizes these impacts as evidence that the proposed GS-3 rate design is unreasonable
18 or inconsistent with cost causation.²³

²² Walmart Statement No. 1, pp. 3–4.

²³ Walmart Statement No. 1, pp. 6–9.

1 Walmart's testimony focuses on the effect of the proposed rate changes on its
2 individual facilities and does not present evidence that the proposed GS-3 rate design
3 results in over-recovery from the GS-3 class as a whole.
4

5 **Q. Are Walmart's concerns indicative of broader GS-3 rate design problems?**

6 A. No. Walmart's testimony reflects the experience of a specific customer with unique usage
7 characteristics and does not establish that the proposed GS-3 rate design is unreasonable
8 for the GS-3 customer class overall. The fact that a particular customer experiences higher
9 bill impacts under a revised rate design does not, by itself, indicate a flaw in the underlying
10 rate structure.

11 No other GS-3 customer presented testimony indicating that the proposed GS-3 rate
12 design is inconsistent with cost responsibility or produces unjust or unreasonable results
13 for the GS-3 class.
14

15 **Q. Is the proposed GS-3 rate design reasonable from a cost and rate design perspective?**

16 A. Yes. The proposed GS-3 rate design reflects the cost characteristics of serving medium and
17 large commercial customers and is consistent with established rate design principles,
18 including cost causation and class responsibility. As shown by the Company's cost of
19 service study, both the proposed GS-3 customer charge and the proposed GS-3 demand
20 charge are closely aligned with cost-based levels, which indicates that the proposed rate
21 design reflects underlying cost responsibility rather than arbitrary reallocation.

1 Nothing in the record demonstrates that the proposed GS-3 rate design departs from
2 Commission precedent or produces unjust or unreasonable results for the GS-3 customer
3 class.

4
5 **Q. What conclusions can be drawn regarding GS-3 rate design?**

6 A. The GS-3 rate design issues raised in this proceeding are limited to concerns expressed by
7 a single customer and do not reflect a broader problem with the proposed GS-3 rate
8 structure. Walmart's testimony does not establish that the proposed GS-3 rate design is
9 inconsistent with cost causation, unreasonable, or inappropriate for the GS-3 class.
10 Accordingly, the proposed GS-3 rate design is reasonable and should be approved.

11
12 **VII. LARGE LOAD CUSTOMER ISSUES**

13 **Q. What large load customer issues have been raised in this proceeding?**

14 A. Several intervenors raise concerns related to large load customers, including customers
15 served under Rate Schedule LP-5. In particular, the OCA, through the testimony of Mr.
16 Colton, and CAUSE-PA, through the testimony of Mr. Cicero, raise issues related to the
17 Company's treatment of large load customers. These concerns generally fall into two
18 categories. First, these parties comment on changes to the LP-5 customer charge. Second,
19 they assert that large load customers, including data centers, are driving increases in costs

1 for other customers and therefore should be subject to different rate structures or
2 surcharges, including the creation of a new customer class.²⁴

3
4 **Q. What distribution service does PPL Electric provide to LP-5 customers?**

5 A. Customers served under Rate Schedule LP-5 take service at 69 kV or higher and therefore
6 do not utilize PPL Electric's distribution system in the manner of lower-voltage customers.
7 As a result, the distribution services provided to LP-5 customers are limited to basic
8 customer-related functions, including the provision of a meter, meter reading, billing, and
9 related customer service activities. Consistent with this service arrangement, LP-5
10 customers are not assessed volumetric or demand-based distribution charges, and the only
11 distribution charge applicable under the LP-5 tariff is the fixed monthly customer charge.

12
13 **Q. Have any parties raised concerns regarding the LP-5 customer charge?**

14 A. Yes. OCA and CAUSE-PA comment on the LP-5 customer charge reflected in the
15 Company's proposed rates. However, the proposed LP-5 customer charge changes only
16 from \$994.00 per month to \$993.68 per month, which represents a de minimis change.

17
18 **Q. Why did the LP-5 customer charge change slightly under the proposed rates?**

19 A. The small change in the LP-5 customer charge does not reflect a policy decision or a
20 material change in cost responsibility, as suggested by OCA and CAUSE-PA. Instead, it

²⁴ OCA Statement 8, pp. 87–98; CAUSE-PA Statement No. 1, pp. 7–9.

1 results from routine test-year mechanics, including changes in customer counts and minor
2 adjustments to class-level other revenues. These routine adjustments flow through the class
3 revenue requirement and rate design calculations and do not reflect a substantive shift in
4 rate design or cost allocation.

5
6 **Q. Have any parties proposed creating a separate rate schedule, such as an “LP-6,”**
7 **specifically for data center customers?**

8 A. Yes. OCA, through the testimony of Mr. Colton, proposes the creation of a new rate
9 schedule specifically for data center customers, sometimes referred to as an “LP-6” rate.
10 That proposal would define a customer class based on industry type, rather than on load
11 characteristics or cost causation.

12
13 **Q. Has the Company indicated a willingness to create a separate LP-6 rate schedule for**
14 **certain large load customers?**

15 A. Yes. In rebuttal testimony, Company witness Joe Lookup states that PPL Electric is not
16 opposed to creating a new LP-6 rate class for customers with peak demands of 100 MW²⁵
17 or greater, and explains that such a rate class could be used to address certain policy
18 considerations raised by other parties, including the allocation of a portion of Universal
19 Service Rider costs, without altering the Company’s distribution revenue requirement or
20 underlying cost allocation methodologies.²⁶

²⁶ See PPL Electric Statement No. 16-R.

1
2 **Q. What customer charge do you recommend for the proposed LP-6 rate schedule at this**
3 **time?**

4 A. At this time, I recommend that the customer charge for the proposed LP-6 rate schedule be
5 set equal to the customer charge proposed for Rate Schedule LP-5. Because LP-6 is a newly
6 proposed rate schedule and there is currently limited information regarding the number of
7 customers that will ultimately take service under LP-6 or their specific cost characteristics,
8 there is not yet a sufficient basis to develop a distinct, cost-based customer charge for that
9 class.

10
11 **Q. Why is it reasonable to use the LP-5 customer charge for LP-6 on an interim basis?**

12 A. Using the LP-5 customer charge for LP-6 on an interim basis is reasonable because both
13 rate schedules serve very large, high-voltage customers that receive limited distribution
14 services. As customers are added to the LP-6 rate schedule over time and additional
15 information becomes available regarding their cost of service, the appropriate customer
16 charge for LP-6 can be evaluated and updated in future PPL rate cases using a more
17 complete cost record.

18
19 **Q. Does this recommendation preclude future adjustments to the LP-6 customer charge?**

20 A. No. This recommendation is intended as a practical and reasonable starting point given the
21 limited information currently available. The LP-6 customer charge should be revisited and

1 refined in subsequent PPL rate cases as the LP-6 customer base develops and more detailed
2 cost-of-service information is available to support a class-specific customer charge.

3
4 **Q. Some parties argue that large load customers are driving increases in costs for other**
5 **customers. What sources do they rely on for that claim?**

6 A. In this proceeding, OCA, through Mr. Colton's testimony, relies on statements from the
7 PJM Independent Market Monitor and a study prepared by Synapse Energy Economics for
8 Sierra Club to support claims that large load customers, including data centers, are
9 materially contributing to higher wholesale market costs and, by extension, higher
10 customer bills.

11
12 **Q. Does PJM load data support the conclusion that large load customers are the primary**
13 **driver of recent wholesale cost increases?**

14 A. No. PJM's historical load data provide important context that is not reflected in the
15 intervenors' narrative. PJM reports that its all-time summer peak load of approximately
16 165,500 MW occurred in 2006. In contrast, more recent summer peaks have been
17 materially lower, including approximately 147,000 MW in 2023 and approximately
18 153,000 MW in 2024. This data indicates that PJM peak load has not increased steadily
19 over the past decade.²⁷

²⁷ PJM Interconnection, 2024 Load Forecast Report, at pp. 3–5 (reporting historical annual coincident peak loads, including a PJM all-time summer peak of approximately 165,500 MW in 2006, compared to summer peaks of approximately 147,000 MW in 2023 and 153,000 MW in 2024).

1 While PJM’s long-term load forecasts project significant growth in future peak
2 demand, those projections extend over a multi-decade horizon and are driven by a
3 combination of factors, including electrification, economic growth, and population trends.
4 PJM has also emphasized that current reliability and price pressures reflect the combined
5 effects of generator retirements, delays in new resource entry, interconnection constraints,
6 and market design features, rather than load growth alone.²⁸

7
8 **Q. If PJM load growth is not the sole driver, what is a primary reason wholesale capacity**
9 **and energy costs have increased in recent years?**

10 A. A primary driver of recent increases in wholesale capacity and energy costs is the structure
11 of PJM’s competitive wholesale market following electric industry restructuring, under
12 which generation investment decisions are made by competitive suppliers rather than
13 through state-regulated, long-term integrated resource planning by vertically integrated
14 utilities. In this framework, PJM’s capacity market is intended to provide the long-run price
15 signal necessary to support new generation investment. However, multiple analyses have
16 found that, for extended periods, capacity prices in PJM were well below levels needed to
17 incent new entry, followed by a sharp price response once resource margins tightened.²⁹
18 While customers benefited from relatively low capacity prices in prior years, current price

²⁸ PJM Interconnection, 2024 Resource Adequacy Analysis and State of the Market Report, Vol. II, at pp. 6–12, 45–52 (explaining that recent reliability and wholesale price pressures reflect generator retirements, delays in new resource entry, interconnection backlogs, and market design factors, rather than load growth alone).

²⁹ Severin Borenstein, *The U.S. Electricity Industry After 20 Years of Restructuring*, National Bureau of Economic Research Working Paper No. 21113 (2015), pp. 1–6, 23–27; John Wilson, “*Missing Money*” *Revisited: Evolution of PJM’s Reliability Pricing Model*, American Public Power Association (2018), pp. 3–7.

1 levels reflect a market reaction to resource scarcity driven by generator retirements,
2 delayed new entry, and market design features, rather than load growth alone.³⁰
3

4 **VIII. EV DCFC RATE**

5 **Q. What issue has Walmart raised regarding electric vehicle charging rates in this**
6 **proceeding?**

7 A. Walmart raises concerns regarding the rate treatment applicable to public direct current fast
8 charging (“DCFC”) electric vehicle charging stations. In its testimony, Walmart asserts that
9 existing commercial and industrial distribution rates that include demand charges may
10 create economic barriers to the deployment of public DCFC infrastructure, particularly
11 during early stages of EV adoption when charger utilization is relatively low. Based on
12 these concerns, Walmart recommends that the Commission direct PPL Electric to work
13 with stakeholders to develop a DCFC-specific distribution rate that relies primarily on
14 volumetric charges rather than demand-based charges.³¹
15

16 **Q. Do demand-based distribution charges inappropriately penalize DC fast charging**
17 **facilities?**

18 A. No. In my professional judgment, demand charges serve an important cost-causation
19 function for loads such as DC fast charging facilities that are characterized by low load

³⁰ *PJM’s Electric Capacity Market: Background and Current Issues*, Congressional Research Service, R48553 (June 2, 2025), pp. 7–13, 19–22; *Drivers of PJM’s Capacity Market Price Surge and Its Impact on DC Electric Customers*, Synapse Energy Economics (May 21, 2025), pp. 1–4, 14–20.

³¹ Walmart Statement No. 1, pp. 22-25.

1 factors and highly intermittent usage. DCFC stations are designed to deliver very high
2 power over short periods of time, and those charging events can contribute to distribution
3 system peak demand. Demand charges reflect the capacity and infrastructure costs
4 associated with standing ready to serve that type of “peaky” load, even when total energy
5 consumption is relatively modest. Eliminating demand charges for DCFC customers would
6 shift those capacity-related costs to other customers who do not impose similar peak
7 demands on the distribution system.

8
9 **Q. Does PPL Electric’s existing rate structure already mitigate some of the concerns**
10 **raised by Walmart?**

11 A. Yes. PPL Electric’s distribution demand charges are relatively modest and are limited to
12 recovering distribution-related capacity costs. At the same time, generation supply charges
13 applicable to DCFC customers are already assessed on a volumetric (\$/kWh) basis,
14 meaning that DCFC customers pay generation and energy costs in direct proportion to their
15 usage. As a result, the existing rate design already combines volumetric pricing for energy-
16 related costs with demand-based pricing for distribution capacity costs. Taken together, this
17 structure appropriately reflects cost causation and provides balanced price signals without
18 foreclosing the development of DC fast charging infrastructure.

19

1 **IX. RULE-6 CHANGES**

2 **Q. What issues have parties raised regarding the Company's proposed modifications to**
3 **Rule 6?**

4 A. Two intervenors comment on the Company's proposed revisions to Rule 6, which governs
5 auxiliary service for customers with on-site generation. In particular, the PP&L Industrial
6 Customer Alliance ("PPLICA"), through the testimony of Ms. LaConte, addresses the
7 scope and application of the proposed Rule 6 capacity reservation charge and recommends
8 clarification regarding how that charge would be applied. In addition, SEF, through the
9 testimony of Mr. Costlow, discusses standby service and raises broader concerns regarding
10 rate design for customers with on-site generation.³²

11
12 **Q. What is the purpose of Rule 6 as proposed by the Company?**

13 A. Rule 6 is intended to ensure that customers with on-site generation who rely on PPL
14 Electric to provide auxiliary or backup service pay appropriately for the distribution
15 capacity that must be reserved to serve them when their on-site generation is unavailable.
16 The rule is a planning and cost-allocation mechanism designed to reflect the distribution
17 system resources required to stand ready to serve those customers, rather than a rate design
18 change intended to increase revenues or alter underlying cost responsibility principles.

19

³² PPLICA Statement No. 1, pp. 9–10; SEF Statement No. 1, pp. 27–28.

1 **Q. Do intervenors oppose the concept of Rule 6 as proposed by the Company?**

2 A. No intervenor opposes the general concept of Rule 6 or disputes the appropriateness of
3 requiring customers with on-site generation to contribute to the cost of distribution capacity
4 that must be reserved to serve them. Rather, intervenor testimony focuses on clarifying
5 how the proposed Rule 6 provisions would be applied and ensuring that the resulting
6 charges are limited to distribution-related costs.

7
8 **Q. What clarification does PPLICA recommend regarding the proposed Rule 6 capacity**
9 **reservation charge?**

10 A. PPLICA recommends that the Company clarify that the Rule 6 capacity reservation charge
11 applies only to distribution demand charges and does not affect generation or transmission
12 charges. This clarification is intended to ensure that Rule 6 operates consistently with its
13 stated purpose, recovering distribution system capacity costs, without expanding its
14 application beyond distribution service or creating ambiguity regarding cost responsibility.

15
16 **Q. Is that clarification reasonable?**

17 A. Yes. Clarifying that the Rule 6 capacity reservation charge is limited to distribution demand
18 charges is reasonable and appropriate. Rule 6 addresses the need for distribution facilities
19 to be available to serve customers when on-site generation is not operating. It does not alter
20 wholesale power supply arrangements or transmission service, which are governed by
21 separate tariffs and regulatory frameworks. Limiting Rule 6 to distribution demand charges

1 ensures that customers pay for the specific costs they cause while avoiding unintended
2 overlap with generation or transmission cost recovery.
3

4 **Q. Does the proposed Rule 6 modification change the Company's overall revenue**
5 **requirement or class cost responsibility?**

6 A. No. Rule 6 is a tariff provision that affects how certain distribution costs are assigned to
7 individual customers with on-site generation based on their service characteristics. It does
8 not change the Company's overall revenue requirement, nor does it reallocate costs among
9 customer classes. Instead, it improves the alignment between cost causation and cost
10 recovery for a specific subset of customers.
11

12 **Q. What conclusions can be drawn regarding the proposed Rule 6 modifications?**

13 A. The proposed Rule 6 modifications represent a reasonable and targeted refinement to the
14 Company's Rules for Electric Service that support sound distribution system planning and
15 cost responsibility. Intervenor testimony does not challenge the underlying rationale for
16 Rule 6 and instead seeks clarification to ensure its proper application. With appropriate
17 clarification that the capacity reservation charge applies only to distribution demand
18 charges, the proposed Rule 6 modifications are consistent with cost-of-service principles
19 and do not raise broader rate design or policy concerns.
20

1 **Q. Does your direct testimony require clarification regarding the calculation of the Rule**
2 **6 back-up power reservation charge?**

3 A. Yes. I note a calculation error in the illustrative rates associated with the Rule 6 back-up
4 power reservation charge. As set forth in the Company's proposed tariff (PPL Electric
5 Exhibit GEO-1), the back-up power reservation charge is defined as 30 percent of the
6 applicable standard distribution demand charges under the customer's otherwise applicable
7 rate schedule. However, in preparing the illustrative rate calculations included with the
8 tariff, I inadvertently applied a 20 percent factor rather than the 30 percent factor specified
9 in Rule 6. This was a clerical error in the calculation of the illustrative charges and does
10 not reflect a change in policy intent or the design of Rule 6 itself.

11
12 **Q. Does this error affect the underlying structure or purpose of Rule 6?**

13 A. No. The tariff language governing Rule 6 is clear that the back-up power reservation charge
14 is calculated as 30 percent of standard distribution demand charges, and that tariff language
15 controls. The purpose of Rule 6 remains to recover a discounted portion of distribution
16 capacity costs associated with reserving back-up service for customers with on-site
17 generation. Correcting the calculation to reflect the 30 percent factor specified in the tariff
18 simply aligns the illustrative rates with the filed tariff language and does not alter cost
19 responsibility, rate design principles, or the application of Rule 6.

20

Q. How are the Rule 6 back-up power reservation charges calculated under the proposed tariff?

A. Table 5 presents the monthly back-up power reservation charges calculated in accordance with Rule 6 of the Company's proposed tariff, using the updated distribution demand charges reflected in the Company's rebuttal revenue requirement, as discussed later in this testimony. As specified in the tariff, the back-up power reservation charge is equal to 30 percent of the applicable standard distribution demand charge under Rate Schedule GS-3, LP-4, or LP-5, and the table applies that factor to the updated rates to show the resulting discounted reservation charges on a per-kilowatt basis.

Table 5 – Back-Up Power Reservation Charges

Back-Up Demand Charge

GS-3	\$1.659/kW
LP-4	\$1.204/kW
LP-5	\$0.000/kW

X. UPDATED RATE DESIGN

Q. Has the Company modified its proposed revenue requirement in rebuttal?

A. Yes. In rebuttal testimony, the Company has updated its proposed revenue requirement and class cost allocation as discussed by Company's revenue requirement witnesses (see, e.g., PPL Electric St. No. 6-R) and the Company's cost-of-service witness Bickey Rimal (PPL

1 Electric St. No. 7-R). These witnesses explain the basis for the revised revenue requirement
2 and the specific cost-related changes and the modifications to the class cost allocation.
3

4 **Q. Does your rebuttal testimony revise the Company's revenue requirement?**

5 A. No, I do not independently recalculate or revise the Company's proposed revenue
6 requirement. Instead, my rebuttal testimony reflects the updated revenue requirement as
7 presented by the Company in rebuttal and applies that updated revenue requirement using
8 the same rate design methodology and analytical framework I used in my direct testimony.
9

10 **Q. What updated exhibits are you sponsoring in rebuttal to reflect these changes?**

11 A. I am sponsoring three updated exhibits in rebuttal:

- 12 • **Exhibit SWW-1R:** Expected bill impacts for the average customer on each rate
13 schedule, reflecting the Company's updated revenue requirement;
- 14 • **Exhibit SWW-2R - Response to Filing Requirement IV-C:** Revenue impact of
15 proposed rates, showing how the revised revenue requirement is recovered across rate
16 schedules; and
- 17 • **Exhibit SWW-3R - Response to Filing Requirement IV-D:** Bill impacts by usage
18 interval, illustrating how impacts vary across different levels of customer usage.

19 Together, these exhibits provide a transparent and consistent view of the rate impacts
20 associated with the Company's rebuttal revenue requirement using the same analytical
21 framework applied in my direct testimony.

1

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

3 A. Yes, it does.

PPL Electric Utilities Corporation
Bill Impact Summary

	Direct Testimony	November Correction	Rebuttal	Change from Nov to Rebuttal
Residential	7.00%	7.99%	7.71%	(0.28%)
GS-1	6.75%	7.78%	8.78%	0.99%
GS-3	6.75%	3.22%	3.36%	0.14%
LP-4	2.55%	2.88%	2.84%	(0.04%)
LP-5	-0.006%	-0.004%	-0.004%	0.00%
SA - LED	17.53%	18.71%	18.50%	(0.21%)
SM(R) MV, OH, Wood- 3,350 Lumens	13.12%	14.01%	13.85%	(0.16%)
SHS HPS, UG, Low- 9,500 Lumens	15.80%	16.87%	16.67%	(0.19%)
SLE LED, OH, Wood- 4,900 Lumens	16.19%	17.28%	17.08%	(0.20%)
SE Customer Owned Poles	6.55%	6.99%	6.91%	(0.08%)
TS (R)	9.10%	9.71%	9.60%	(0.11%)

**PPL Electric Utilities Corporation
Rate Schedule: RS Residential Service
FPFTY Impact of Proposed Rates On Average Bills**

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$14.09/Bill	1 Month	\$14.09	\$17.00/Bill	1 Month	\$17.00	\$2.91	20.7%
Energy Charge	\$0.03534/kWh	918 kWh	\$32.43	\$0.05102/kWh	918 kWh	\$46.82	\$14.39	44.4%
Demand Charge								
TCJA	-8.0%		-\$3.72				\$3.72	-100.0%
SMR 2	\$1.50/Bill	1 Month	\$1.50				-\$1.50	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00220/kWh	918 kWh	\$2.02	\$0.00220/kWh	918 kWh	\$2.02	\$0.00	0.0%
USR	\$0.01111/kWh	918 kWh	\$10.20	\$0.01111/kWh	918 kWh	\$10.20	\$0.00	0.0%
SDER	\$0.00184/kWh	918 kWh	\$1.69				-\$1.69	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$4.36</u>				-\$4.36	-100.0%
Distribution Subtotal			\$62.56			\$76.04	\$13.48	21.5%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.18</u>				<u>\$0.18</u>	<u>-100.0%</u>
Total Distribution Charges			\$62.38			\$76.04	\$13.65	21.9%
GSC-1	\$0.09166/kWh	918 kWh	\$84.12	\$0.09166/kWh	918 kWh	\$84.12	\$0.00	0.0%
TSC	<u>\$0.03324/kWh</u>	<u>918 kWh</u>	<u>\$30.51</u>	<u>\$0.03324/kWh</u>	<u>918 kWh</u>	<u>\$30.51</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$114.62			\$114.62	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$114.62			\$114.62	\$0.00	0.0%
Total Average Monthly Bill			\$177.01			\$190.66	\$13.65	7.7%

PPL Electric Utilities Corporation
Rate Schedule: RTS Residential Thermal Storage
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$18.06/Bill	1 Month	\$18.06	\$17.00/Bill	1 Month	\$17.00	-\$1.06	-5.9%
Energy Charge	\$0.02367/kWh	1,664 kWh	\$39.39	\$0.05102/kWh	1,664 kWh	\$84.91	\$45.52	115.5%
Demand Charge								
TCJA	-8.0%		-\$4.60				\$4.60	-100.0%
SMR 2	\$1.50/Bill	1 Month	\$1.50				-\$1.50	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00220/kWh	1,664 kWh	\$3.66	\$0.00220/kWh	1,664 kWh	\$3.66	\$0.00	0.0%
USR	\$0.01111/kWh	1,664 kWh	\$18.49	\$0.01111/kWh	1,664 kWh	\$18.49	\$0.00	0.0%
SDER	\$0.00184/kWh	1,664 kWh	\$3.06				-\$3.06	-100.0%
DSIC	7.5%		\$5.97				-\$5.97	-100.0%
Distribution Subtotal			\$85.53			\$124.06	\$38.53	45.1%
State Tax Adjustment	-0.28%		-\$0.239				\$0.24	-100.0%
Total Distribution Charges			\$85.29			\$124.06	\$38.77	45.5%
GSC-1	\$0.09166/kWh	1,664 kWh	\$152.54	\$0.09166/kWh	1,664 kWh	\$152.54	\$0.00	0.0%
TSC	\$0.03324/kWh	1,664 kWh	\$55.32	\$0.03324/kWh	1,664 kWh	\$55.32	\$0.00	0.0%
Energy & Transmission Subtotal			\$207.86			\$207.86	\$0.00	0.0%
State Tax Adjustment	0.001%		\$0.00	0.001%		\$0.00	\$0.00	0.0%
Total Energy & Transmission Charges			\$207.86			\$207.86	\$0.00	0.0%
Total Average Monthly Bill			\$293.15			\$331.92	\$38.77	13.2%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Single Phase General Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$22.00/Bill	1 Month	\$22.00	\$30.00/Bill	1 Month	\$30.00	\$8.00	36.4%
Energy Charge								
Demand Charge	\$4.361/kW	5.25 kW	\$22.88	\$6.532/kW	5.25 kW	\$34.27	\$11.39	49.8%
TCJA	-8.0%		-\$3.59				\$3.59	-100.0%
SMR 2	\$3.03/Bill	1 Month	\$3.03				-\$3.03	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00166/kWh	1,051 kWh	\$1.75	\$0.00166/kWh	1,051 kWh	\$1.75	\$0.00	0.0%
USR								
SDER	\$0.00092/kWh	1,051 kWh	\$0.97				-\$0.97	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$3.53</u>				-\$3.53	-100.0%
Distribution Subtotal			\$50.55			\$66.01	\$15.47	30.6%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.142</u>				<u>\$0.14</u>	<u>-100.0%</u>
Total Distribution Charges			\$50.40			\$66.01	\$15.61	31.0%
GSC-1	\$0.08956/kWh	1,051 kWh	\$94.16	\$0.08956/kWh	1,051 kWh	\$94.16	\$0.00	0.0%
<u>TSC</u>	<u>\$0.03158/kWh</u>	<u>1,051 kWh</u>	<u>\$33.20</u>	<u>\$0.03158/kWh</u>	<u>1,051 kWh</u>	<u>\$33.20</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$127.36			\$127.36	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$127.36			\$127.36	\$0.00	0.0%
Total Average Monthly Bill			\$177.77			\$193.37	\$15.61	8.8%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Volunteer & Non-Profit Organizations
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$14.09/Bill	1 Month	\$14.09	\$17.00/Bill	1 Month	\$17.00	\$2.91	20.7%
Energy Charge	\$0.03534/kWh	2,533 kWh	\$89.52	\$0.05102/kWh	2,533 kWh	\$129.24	\$39.72	44.4%
Demand Charge								
TCJA	-8.0%		-\$8.29				\$8.29	-100.0%
SMR 2	\$1.50/Bill	1 Month	\$1.50				-\$1.50	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00220/kWh	2,533 kWh	\$5.57	\$0.00220/kWh	2,533 kWh	\$5.57	\$0.00	0.0%
USR	\$0.01111/kWh	2,533 kWh	\$28.14	\$0.01111/kWh	2,533 kWh	\$28.14	\$0.00	0.0%
SDER	\$0.00184/kWh	2,533 kWh	\$4.66				-\$4.66	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$10.14</u>				<u>-\$10.14</u>	<u>-100.0%</u>
Distribution Subtotal			\$145.33			\$179.96	\$34.63	23.8%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.41</u>				<u>\$0.41</u>	<u>-100.0%</u>
Total Distribution Charges			\$144.92			\$179.96	\$35.04	24.2%
GSC-1	\$0.08956/kWh	2,533 kWh	\$226.87	\$0.08956/kWh	2,533 kWh	\$226.87	\$0.00	0.0%
<u>TSC</u>	<u>\$0.03158/kWh</u>	<u>2,533 kWh</u>	<u>\$80.00</u>	<u>\$0.03158/kWh</u>	<u>2,533 kWh</u>	<u>\$80.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$306.87			\$306.87	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$306.87			\$306.87	\$0.00	0.0%
Total Average Monthly Bill			\$451.79			\$486.83	\$35.04	7.8%

**PPL Electric Utilities Corporation
Rate Schedule: GH-2(R) Space Heating
FPFTY Impact of Proposed Rates On Average Bills**

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$22.00/Bill	1 Month	\$22.00	\$30.00/Bill	1 Month	\$30.00	\$8.00	36.4%
Energy Charge								
Demand Charge	\$3.955/kW	13.08 kW	\$51.71	\$6.532/kW	13.08 kW	\$85.41	\$33.69	65.2%
TCJA	-8.0%		-\$5.90				\$5.90	-100.0%
SMR 2	\$3.03/Bill	1 Month	\$3.03				-\$3.03	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00166/kWh	1,991 kWh	\$3.30	\$0.00166/kWh	1,991 kWh	\$3.30	\$0.00	0.0%
USR								
SDER	\$0.00092/kWh	1,991 kWh	\$1.83				-\$1.83	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$5.70</u>				<u>-\$5.70</u>	<u>-100.0%</u>
Distribution Subtotal			\$81.67			\$118.71	\$37.04	45.4%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.229</u>				<u>\$0.23</u>	<u>-100.0%</u>
Total Distribution Charges			\$81.44			\$118.71	\$37.27	45.8%
GSC-1	\$0.08956/kWh	1,991 kWh	\$178.31	\$0.08956/kWh	1,991 kWh	\$178.31	\$0.00	0.0%
<u>TSC</u>	<u>\$0.03158/kWh</u>	<u>1,991 kWh</u>	<u>\$62.87</u>	<u>\$0.03158/kWh</u>	<u>1,991 kWh</u>	<u>\$62.87</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$241.18			\$241.18	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$241.19			\$241.19	\$0.00	0.0%
Total Average Monthly Bill			\$322.63			\$359.90	\$37.27	11.6%

**PPL Electric Utilities Corporation
Rate Schedule: BL Borderline Service
FPFTY Impact of Proposed Rates On Average Bills**

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge								
Energy Charge	\$0.04795/kWh	14,512 kWh	\$695.85	\$0.06739/kWh	14,512 kWh	\$977.89	\$282.05	40.5%
Demand Charge								
TCJA	-8.0%		-\$55.67				\$55.67	-100.0%
SMR 2	\$3.03/Bill	1 Month	\$3.03				-\$3.03	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00166/kWh	14,512 kWh	\$24.09	\$0.00166/kWh	14,512 kWh	\$24.09	\$0.00	0.0%
USR								
SDER	\$0.00092/kWh	14,512 kWh	\$13.35				-\$13.35	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$51.05</u>				<u>-\$51.05</u>	<u>-100.0%</u>
Distribution Subtotal			\$731.69			\$1,001.98	\$270.29	36.9%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$2.05</u>				<u>\$2.05</u>	<u>-100.0%</u>
Total Distribution Charges			\$729.64			\$1,001.98	\$272.34	37.3%
GSC-1	\$0.08956/kWh	14,512 kWh	\$1,299.69	\$0.08956/kWh	14,512 kWh	\$1,299.69	\$0.00	0.0%
<u>TSC</u>	<u>\$0.03158/kWh</u>	<u>14,512 kWh</u>	<u>\$458.29</u>	<u>\$0.03158/kWh</u>	<u>14,512 kWh</u>	<u>\$458.29</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$1,757.98			\$1,757.98	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.02</u>	<u>0.001%</u>		<u>\$0.02</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$1,758.00			\$1,758.00	\$0.00	0.0%
Total Average Monthly Bill			\$2,487.64			\$2,759.98	\$272.34	10.9%

**PPL Electric Utilities Corporation
Rate Schedule: GS-3 Three Phase General Service
FPFTY Impact of Proposed Rates On Average Bills**

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$60.00/Bill	1 Month	\$60.00	\$78.00/Bill	1 Month	\$78.00	\$18.00	30.0%
Energy Charge								
Demand Charge	\$3.985/kW	52.75 kW	\$210.22	\$5.529/kW	52.75 kW	\$291.67	\$81.45	38.7%
TCJA	-8.0%		-\$21.62				\$21.62	-100.0%
SMR 2	\$3.03/Bill	1 Month	\$3.03				-\$3.03	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00166/kWh	17,231 kWh	\$28.60	\$0.00166/kWh	17,231 kWh	\$28.60	\$0.00	0.0%
USR								
SDER	\$0.00092/kWh	17,231 kWh	\$15.85				-\$15.85	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$22.21</u>				-\$22.21	-100.0%
Distribution Subtotal			\$318.29			\$398.28	\$79.99	25.1%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.891</u>				<u>\$0.89</u>	<u>-100.0%</u>
Total Distribution Charges			\$317.39			\$398.28	\$80.88	25.5%
GSC-1	\$0.08956/kWh	17,231 kWh	\$1,543.18	\$0.08956/kWh	17,231 kWh	\$1,543.18	\$0.00	0.0%
<u>TSC</u>	<u>\$0.03158/kWh</u>	<u>17,231 kWh</u>	<u>\$544.15</u>	<u>\$0.03158/kWh</u>	<u>17,231 kWh</u>	<u>\$544.15</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$2,087.33			\$2,087.33	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.02</u>	<u>0.001%</u>		<u>\$0.02</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$2,087.35			\$2,087.35	\$0.00	0.0%
Total Average Monthly Bill			\$2,404.74			\$2,485.63	\$80.88	3.4%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Volunteer & Non-Profit Organizations
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$14.09/Bill	1 Month	\$14.09	\$17.00/Bill	1 Month	\$17.00	\$2.91	20.7%
Energy Charge	\$0.03534/kWh	5,867 kWh	\$207.33	\$0.05102/kWh	5,867 kWh	\$299.32	\$91.99	44.4%
Demand Charge								
TCJA	-8.0%		-\$17.71				\$17.71	-100.0%
SMR 2	\$1.50/Bill	1 Month	\$1.50				-\$1.50	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00220/kWh	5,867 kWh	\$12.91	\$0.00220/kWh	5,867 kWh	\$12.91	\$0.00	0.0%
USR	\$0.01111/kWh	5,867 kWh	\$65.18	\$0.01111/kWh	5,867 kWh	\$65.18	\$0.00	0.0%
SDER	\$0.00184/kWh	5,867 kWh	\$10.79				-\$10.79	-100.0%
DSIC	7.5%		\$22.06				-\$22.06	-100.0%
Distribution Subtotal			\$316.14			\$394.41	\$78.27	24.8%
State Tax Adjustment	-0.28%		-\$0.89				\$0.89	-100.0%
Total Distribution Charges			\$315.25			\$394.41	\$79.16	25.1%
GSC-1	\$0.08956/kWh	5,867 kWh	\$525.43	\$0.08956/kWh	5,867 kWh	\$525.43	\$0.00	0.0%
TSC	\$0.03158/kWh	5,867 kWh	\$185.27	\$0.03158/kWh	5,867 kWh	\$185.27	\$0.00	0.0%
Energy & Transmission Subtotal			\$710.70			\$710.70	\$0.00	0.0%
State Tax Adjustment	0.001%		\$0.01	0.001%		\$0.01	\$0.00	0.0%
Total Energy & Transmission Charges			\$710.71			\$710.71	\$0.00	0.0%
Total Average Monthly Bill			\$1,025.96			\$1,105.12	\$79.16	7.7%

PPL Electric Utilities Corporation
Rate Schedule: LP-4 Large General Service at 12,470 Voltes
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$169.80/Bill	1 Month	\$169.80	\$235.00/Bill	1 Month	\$235.00	\$65.20	38.4%
Energy Charge								
Demand Charge	\$2.547/kW	965 kW	\$2,457.15	\$4.012/kW	965 kW	\$3,870.47	\$1,413.32	57.5%
TCJA	-8.0%		-\$210.16				\$210.16	-100.0%
SMR 2	\$63.12/Bill	1 Month	\$63.12				-\$63.12	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$1.057/kW	965 kW	\$1,019.71	\$1.057/kW	965 kW	\$1,019.71	\$0.00	0.0%
USR								
SDER	\$123.10/Bill	1 Month	\$123.10				-\$123.10	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$271.70</u>				-\$271.70	-100.0%
Distribution Subtotal			\$3,894.42			\$5,125.19	\$1,230.76	31.6%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$10.904</u>				<u>\$10.90</u>	<u>-100.0%</u>
Total Distribution Charges			\$3,883.52			\$5,125.19	\$1,241.67	32.0%
GSC-1	\$0.04734/kWh	406,485 kWh	\$19,243.01	\$0.04734/kWh	406,485 kWh	\$19,243.01	\$0.00	0.0%
TSC	<u>\$21.350/kW</u>	<u>965 kW</u>	<u>\$20,596.87</u>	<u>\$21.350/kW</u>	<u>965 kW</u>	<u>\$20,596.87</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$39,839.88			\$39,839.88	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.40</u>	<u>0.001%</u>		<u>\$0.40</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$39,840.28			\$39,840.28	\$0.00	0.0%
Total Average Monthly Bill			\$43,723.80			\$44,965.47	\$1,241.67	2.8%

PPL Electric Utilities Corporation
Rate Schedule: LP-5 Large General Service at 69,000 Volts or Higher
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$994.00/Bill	1 Month	\$994.00	\$997.92/Bill	1 Month	\$997.92	\$3.92	0.4%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-\$79.52				\$79.52	-100.0%
SMR 2	\$63.12/Bill	1 Month	\$63.12				-\$63.12	-100.0%
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$1.057/kW	12,794 kW	\$13,522.86	\$1.057/kW	12,794 kW	\$13,522.86	\$0.00	0.0%
USR								
SDER	\$101.50/Bill	1 Month	\$101.50				-\$101.50	-100.0%
<u>DSIC</u>								
Distribution Subtotal			\$14,601.95			\$14,520.78	-\$81.17	-0.6%
<u>State Tax Adjustment</u>	-0.28%		-\$40.885				<u>\$40.89</u>	<u>-100.0%</u>
Total Distribution Charges			\$14,561.06			\$14,520.78	-\$40.28	-0.3%
GSC-1	\$0.04734/kWh	6,070,574 kWh	\$287,380.99	\$0.04734/kWh	6,070,574 kWh	\$287,380.99	\$0.00	0.0%
TSC	<u>\$56.378/kW</u>	<u>12,794 kW</u>	<u>\$721,278.91</u>	<u>\$56.378/kW</u>	<u>12,794 kW</u>	<u>\$721,278.91</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$1,008,659.91			\$1,008,659.91	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$10.09</u>	<u>0.001%</u>		<u>\$10.09</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$1,008,669.99			\$1,008,669.99	\$0.00	0.0%
Total Average Monthly Bill			\$1,023,231.06			\$1,023,190.77	-\$40.28	-0.004%

PPL Electric Utilities Corporation
Rate Schedule: SA Private Area Lighting (LED)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$13.400/Fixture	1 Fixture	\$13.40	\$16.018/Fixture	1 Fixture	\$16.02	\$2.62	19.5%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-\$1.07				\$1.07	-100.0%
SMR 2								
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.026/Fixture	1 Fixture	\$0.03	\$0.026/Fixture	1 kW	\$0.03	\$0.00	0.0%
USR								
SDER	\$0.014/Fixture	1 Fixture	\$0.01				-\$0.01	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$0.93</u>					
Distribution Subtotal			\$13.28			\$16.04	\$2.76	20.8%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.037</u>			<u>\$0.000</u>	<u>\$0.04</u>	<u>-100.0%</u>
Total Distribution Charges			\$13.25			\$16.04	\$2.80	21.1%
GSC-1	\$1.380/Fixture	1 Fixture	\$1.38	\$1.380/Fixture	1 Fixture	\$1.38	\$0.00	0.0%
TSC	<u>\$0.487/Fixture</u>	<u>1 Fixture</u>	<u>\$0.49</u>	<u>\$0.487/Fixture</u>	<u>1 Fixture</u>	<u>\$0.49</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$1.87			\$1.87	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$1.87			\$1.87	\$0.00	0.0%
Total Average Monthly Bill			\$15.11			\$17.91	\$2.80	18.5%

* Sample bill based on the most common lighting type

PPL Electric Utilities Corporation
Rate Schedule: SM(R) Mercury Vapor Street Lighting Service (Overhead, Wood Pole, 3,350 Lumens)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$12.225/Lamp	1 Lamp	\$12.23	\$14.612/Lamp	1 Lamp	\$14.61	\$2.39	19.5%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-\$0.98				\$0.98	-100.0%
SMR 2								
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.082/Lamp	1 Lamp	\$0.08	\$0.082/Lamp	1 Lamp	\$0.08	\$0.00	0.0%
USR								
SDER	\$0.045/Lamp	1 Lamp	\$0.05				-\$0.05	-100.0%
DSIC	7.5%		<u>\$0.85</u>					
Distribution Subtotal			\$12.22			\$14.69	\$2.48	20.3%
State Tax Adjustment	-0.28%		<u>-\$0.034</u>			<u>\$0.000</u>	<u>\$0.03</u>	<u>-100.0%</u>
Total Distribution Charges			\$12.18			\$14.69	\$2.51	20.6%
GSC-1	\$4.397/Lamp	1 Lamp	\$4.40	\$4.397/Lamp	1 Lamp	\$4.40	\$0.00	0.0%
TSC	<u>\$1.551/Lamp</u>	<u>1 Lamp</u>	<u>\$1.55</u>	<u>\$1.551/Lamp</u>	<u>1 Lamp</u>	<u>\$1.55</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$5.95			\$5.95	\$0.00	0.0%
State Tax Adjustment	0.001%		<u>\$0.00</u>	0.001%		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$5.95			\$5.95	\$0.00	0.0%
Total Average Monthly Bill			\$18.13			\$20.64	\$2.51	13.9%

* Sample bill based on the most common lighting type

PPL Electric Utilities Corporation
Rate Schedule: SHS High Pressure Sodium Street Light Service (Underground, Low Mount, =9,500 Lumens)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$20.360/Lamp	1 Lamp	\$20.36	\$24.344/Lamp	1 Lamp	\$24.34	\$3.98	19.6%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-\$1.63				\$1.63	-100.0%
SMR 2								
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.071/Lamp	1 Lamp	\$0.07	\$0.071/Lamp	1 Lamp	\$0.07	\$0.00	0.0%
USR								
SDER	\$0.039/Lamp	1 Lamp	\$0.04				-\$0.04	-100.0%
DSIC	7.5%		\$1.41					
Distribution Subtotal			\$20.24			\$24.42	\$4.17	20.6%
State Tax Adjustment	-0.28%		-\$0.057			\$0.000	\$0.06	-100.0%
Total Distribution Charges			\$20.19			\$24.42	\$4.23	20.9%
GSC-1	\$3.824/Lamp	1 Lamp	\$3.82	\$3.824/Lamp	1 Lamp	\$3.82	\$0.00	0.0%
TSC	\$1.348/Lamp	1 Lamp	\$1.35	\$1.348/Lamp	1 Lamp	\$1.35	\$0.00	0.0%
Energy & Transmission Subtotal			\$5.17			\$5.17	\$0.00	0.0%
State Tax Adjustment	0.001%		\$0.00	0.001%		\$0.00	\$0.00	0.0%
Total Energy & Transmission Charges			\$5.17			\$5.17	\$0.00	0.0%
Total Average Monthly Bill			\$25.36			\$29.59	\$4.23	16.7%

* Sample bill based on the most common lighting type

PPL Electric Utilities Corporation
Rate Schedule: SLE Light Emitting Diode (LED) Street Light Service (Overhead, Wood Pole, =4,900 Lumens)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge	\$14.240/Lamp	1 Lamp	\$14.24	\$17.009/Lamp	1 Lamp	\$17.01	\$2.77	19.4%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-\$1.14				\$1.14	-100.0%
SMR 2								
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.043/Lamp	1 Lamp	\$0.04	\$0.043/Lamp	1 Lamp	\$0.04	\$0.00	0.0%
USR								
SDER	\$0.024/Lamp	1 Lamp	\$0.02				-\$0.02	-100.0%
DSIC	7.5%		\$0.99					
Distribution Subtotal			\$14.14			\$17.05	\$2.91	20.6%
State Tax Adjustment	-0.28%		-\$0.040			\$0.000	\$0.04	-100.0%
Total Distribution Charges			\$14.11			\$17.05	\$2.95	20.9%
GSC-1	\$2.325/Lamp	1 Lamp	\$2.33	\$2.325/Lamp	1 Lamp	\$2.33	\$0.00	0.0%
TSC	\$0.820/Lamp	1 Lamp	\$0.82	\$0.820/Lamp	1 Lamp	\$0.82	\$0.00	0.0%
Energy & Transmission Subtotal			\$3.15			\$3.15	\$0.00	0.0%
State Tax Adjustment	0.001%		\$0.00	0.001%		\$0.00	\$0.00	0.0%
Total Energy & Transmission Charges			\$3.15			\$3.15	\$0.00	0.0%
Total Average Monthly Bill			\$17.25			\$20.20	\$2.95	17.1%

* Sample bill based on the most common lighting type

PPL Electric Utilities Corporation
Rate Schedule: SE Energy Only Street Lighting (Customer Owned Poles)*
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Customer Charge								
Energy Charge	\$0.06026/kWh	19,885 kWh	\$1,198.25	\$0.07320/kWh	19,885 kWh	\$1,455.56	\$257.31	21.5%
Demand Charge								
TCJA	-8.0%		-\$95.86				\$95.86	-100.0%
SMR 2								
CER	-\$0.01/Bill	1 Month	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00166/kWh	19,885 kWh	\$33.01	\$0.00166/kWh	19,885 kWh	\$33.01	\$0.00	0.0%
USR								
SDER	\$0.00092/kWh	19,885 kWh	\$18.29				-\$18.29	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$86.53</u>				-\$86.53	-100.0%
Distribution Subtotal			\$1,240.21			\$1,488.57	\$248.36	20.0%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$3.47</u>			<u>\$0.00</u>	<u>\$3.47</u>	<u>-100.0%</u>
Total Distribution Charges			\$1,236.74			\$1,488.57	\$251.83	20.4%
GSC-1	\$0.08956/kWh	19,885 kWh	\$1,780.87	\$0.08956/kWh	19,885 kWh	\$1,780.87	\$0.00	0.0%
<u>TSC</u>	<u>\$0.03158/kWh</u>	<u>19,885 kWh</u>	<u>\$627.96</u>	<u>\$0.03158/kWh</u>	<u>19,885 kWh</u>	<u>\$627.96</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$2,408.83			\$2,408.83	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.02</u>	<u>0.001%</u>		<u>\$0.02</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$2,408.85			\$2,408.85	\$0.00	0.0%
Total Average Monthly Bill			\$3,645.59			\$3,897.42	\$251.83	6.9%

* Sample bill based on the most common lighting type

PPL Electric Utilities Corporation
Rate Schedule: TS (R) Municipal Traffic Signal Lighting Service
FPFTY Impact of Proposed Rates On Average Bills

	Current Rates	Volumes	Current Average Bills	Proposed Rates	Volumes	Proposed Average Bills	Change in Average Bills	
Per Watt Charge	\$0.07496/watt	403 Watts	\$30.18	\$0.09049/watt	403 Watts	\$36.43	\$6.25	20.7%
Energy Charge								
Demand Charge								
TCJA	-8.0%		-\$2.41				\$2.41	-100.0%
SMR 2								
CER	-\$0.01/Bill	1 Watts	-\$0.01				\$0.01	-100.0%
ACR 4	\$0.00121/watt	403 Watts	\$0.49	\$0.00121/watt	403 Watts	\$0.49	\$0.00	0.0%
USR								
SDER	\$0.00067/watt	403 Watts	\$0.27				-\$0.27	-100.0%
<u>DSIC</u>	<u>7.5%</u>		<u>\$2.14</u>					
Distribution Subtotal			\$30.65			\$36.92	\$6.27	20.5%
<u>State Tax Adjustment</u>	<u>-0.28%</u>		<u>-\$0.086</u>			<u>\$0.000</u>	<u>\$0.09</u>	<u>-100.0%</u>
Total Distribution Charges			\$30.56			\$36.92	\$6.35	20.8%
GSC-1	\$0.06543/watt	403 Watts	\$26.34	\$0.06543/watt	403 Watts	\$26.34	\$0.00	0.0%
TSC	<u>\$0.02307/watt</u>	<u>403 Watts</u>	<u>\$9.29</u>	<u>\$0.02307/watt</u>	<u>403 Watts</u>	<u>\$9.29</u>	<u>\$0.00</u>	<u>0.0%</u>
Energy & Transmission Subtotal			\$35.63			\$35.63	\$0.00	0.0%
<u>State Tax Adjustment</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>0.001%</u>		<u>\$0.00</u>	<u>\$0.00</u>	<u>0.0%</u>
Total Energy & Transmission Charges			\$35.63			\$35.63	\$0.00	0.0%
Total Average Monthly Bill			\$66.19			\$72.54	\$6.35	9.6%

**PPL Electric Utilities Corporation
Rate Schedule: RS Residential Service
Impact of Proposed Rates On Total Revenues**

Billing Volumes

Customer Months
Annual Energy
Annual Demand

HTY	FTY	FPFTY
15,596,355	15,672,111	15,742,091
14,611,786,546	14,367,424,180	14,446,867,822

Rate Design

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Current Rates Without Riders	Proposed Rates Without Riders	Proposed Rates With Riders (ACR 4 & USR)
\$15.58/Bill	\$14.09/Bill	\$17.00/Bill	\$17.00/Bill
\$0.05049/kWh	\$0.03534/kWh	\$0.05102/kWh	\$0.06433/kWh
-8.0%	-8.0%		
	\$1.50/Bill		
	-\$0.01/Bill		
	\$0.00184/kWh		
7.5%	7.5%		
-0.28%	-0.28%		

Revenue Impacts

Current Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$219,752,642	\$220,820,047	\$221,806,061
\$516,380,537	\$507,744,771	\$510,552,309
(\$58,890,654)	(\$58,285,185)	(\$58,588,670)
\$23,394,533	\$23,508,167	\$23,613,136
(\$155,964)	(\$156,721)	(\$157,421)
\$26,885,687	\$26,436,060	\$26,582,237
\$69,138,724	\$68,347,317	\$68,707,160
(\$2,774,767)	(\$2,774,767)	(\$2,774,767)
\$793,730,737	\$785,671,449	\$789,757,365

Proposed Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$265,138,035	\$266,425,891	\$267,615,546
\$745,493,350	\$733,025,982	\$737,079,196
\$1,010,631,385	\$999,451,872	\$1,004,694,742

Change

\$216,900,647	\$213,780,423	\$214,937,377
27.3%	27.2%	27.2%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Single Phase General Service
Impact of Proposed Rates On Total Revenues

Billing Volumes	HTY	FTY	FPFTY
Customer Months	1,783,303	1,778,262	1,778,853
Annual Energy	1,916,436,485	1,866,108,102	1,859,181,867
Annual Demand	9,608,372	9,380,888	9,370,565

Rate Design	Current Rates	Proposed Rates
Customer Charge	\$22.00/Bill	\$30.00/Bill
Energy Charge		
Demand Charge	\$4.361/kW	\$6.532/kW
TCJA	-8.0%	
SMR 2	\$3.03/Bill	
CER	-\$0.01/Bill	
SDER	\$0.00092/kWh	
DSIC	7.5%	
STAS-D	-0.28%	

Revenue Impacts

Current Rates	HTY	FTY	FPFTY
Customer Charge	\$39,232,657	\$39,121,761	\$39,134,763
Energy Charge			
Demand Charge	\$41,902,110	\$40,910,053	\$40,865,035
TCJA	(\$6,490,781)	(\$6,402,545)	(\$6,399,984)
SMR 2	\$5,403,407	\$5,388,134	\$5,389,924
CER	(\$17,833)	(\$17,783)	(\$17,789)
SDER	\$1,763,122	\$1,716,819	\$1,710,447
DSIC	\$6,373,047	\$6,286,063	\$6,282,648
STAS-D	(\$255,772)	(\$252,281)	(\$252,144)
Total	\$87,909,958	\$86,750,223	\$86,712,902

Proposed Rates	HTY	FTY	FPFTY
Customer Charge	\$53,499,078	\$53,347,856	\$53,365,586
Energy Charge			
Demand Charge	\$62,761,886	\$61,275,962	\$61,208,533
TCJA			
SMR 2			
CER			
SDER			
DSIC			
STAS-D			
Total	\$116,260,964	\$114,623,818	\$114,574,119

Change	\$28,351,007	\$27,873,595	\$27,861,217
	32.3%	32.1%	32.1%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Volunteer / Non-Profit
Impact of Proposed Rates On Total Revenues

Billing Volumes
Customer Months
Annual Energy
Annual Demand

HTY	FTY	FPFTY
7,471	7,451	7,455
19,476,412	18,948,588	18,883,515

Rate Design

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Current Rates Without Riders	Proposed Rates Without Riders	Proposed Rates With Riders (ACR 4 & USR)
\$15.58/Bill \$0.05049/kWh	\$14.09/Bill \$0.03534/kWh	\$17.00/Bill \$0.05102/kWh	\$17.00/Bill \$0.06433/kWh
-8.0%	-8.0%		
	\$1.50/Bill		
	-\$0.01/Bill		
	\$0.00184/kWh		
7.5%	7.5%		
-0.28%	-0.28%		

Revenue Impacts

Current Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$105,272	\$104,986	\$105,034
\$688,296	\$669,643	\$667,343
(\$63,485)	(\$61,970)	(\$61,790)
\$11,207	\$11,177	\$11,182
(\$75)	(\$75)	(\$75)
\$35,837	\$34,865	\$34,746
\$77,721	\$75,812	\$75,583
(\$3,119)	(\$3,043)	(\$3,033)
\$851,654	\$831,397	\$828,990

Proposed Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$127,014	\$126,669	\$126,727
\$993,687	\$966,757	\$963,437
\$1,120,700	\$1,093,426	\$1,090,164

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\$269,046	\$262,030	\$261,173
31.6%	31.5%	31.5%

PPL Electric Utilities Corporation
Rate Schedule: BL Borderline Service
Impact of Proposed Rates On Total Revenues

Billing Volumes
Customer Months
Annual Energy
Annual Demand

HTY	FTY	FPFTY
483	502	501
7,302,079	7,295,573	7,274,464

Rate Design
Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Proposed Rates
\$0.00/Bill	\$0.00/Bill
\$0.04795/kWh	\$0.06739/kWh
-8.0%	
\$3.03/Bill	
-\$0.01/Bill	
\$0.00092/kWh	
7.5%	
-0.28%	

Revenue Impacts
Current Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$350,135	\$349,823	\$348,811
(\$28,011)	(\$27,986)	(\$27,905)
\$1,463	\$1,521	\$1,519
(\$5)	(\$5)	(\$5)
\$6,718	\$6,712	\$6,693
\$25,682	\$25,663	\$25,589
(\$1,031)	(\$1,030)	(\$1,027)
\$354,951	\$354,698	\$353,674

Proposed Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$492,053	\$491,615	\$490,192
\$492,053	\$491,615	\$490,192

Change

\$137,102	\$136,916	\$136,518
38.6%	38.6%	38.6%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Three Phase General Service
Impact of Proposed Rates On Total Revenues

Billing Volumes	HTY	FTY	FPFTY
Customer Months	470,677	474,416	477,654
Annual Energy	8,233,632,568	8,211,077,559	8,235,059,145
Annual Demand	25,323,203	25,093,254	25,219,929

Rate Design	Current Rates	Proposed Rates
Customer Charge	\$60.00/Bill	\$78.00/Bill
Energy Charge		
Demand Charge	\$3.985/kW	\$5.529/kW
TCJA	-8.0%	
SMR 2	\$3.03/Bill	
CER	-\$0.01/Bill	
SDER	\$0.00092/kWh	
DSIC	7.5%	
STAS-D	0.28%	

Revenue Impacts

Current Rates	HTY	FTY	FPFTY
Customer Charge	\$28,240,623	\$28,464,951	\$28,659,249
Energy Charge			
Demand Charge	\$100,912,964	\$99,996,617	\$100,501,417
TCJA	(\$10,332,287)	(\$10,276,925)	(\$10,332,853)
SMR 2	\$1,426,151	\$1,437,480	\$1,447,292
CER	(\$4,707)	(\$4,744)	(\$4,777)
SDER	\$7,574,942	\$7,554,191	\$7,576,254
DSIC	\$10,611,414	\$10,560,147	\$10,613,759
STAS-D	(\$425,871)	(\$423,814)	(\$425,966)
Total	\$138,003,229	\$137,307,903	\$138,034,376

Proposed Rates	HTY	FTY	FPFTY
Customer Charge	\$36,712,810	\$37,004,436	\$37,257,024
Energy Charge			
Demand Charge	\$140,011,989	\$138,740,601	\$139,440,987
TCJA			
SMR 2			
CER			
SDER			
DSIC			
STAS-D			
Total	\$176,724,799	\$175,745,037	\$176,698,011

Change	\$38,721,570	\$38,437,135	\$38,663,635
	28.1%	28.0%	28.0%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Volunteer / Non-Profit
Impact of Proposed Rates On Total Revenues

Billing Volumes
Customer Months
Annual Energy
Annual Demand

HTY	FTY	FPFTY
411	414	417
2,446,171	2,439,470	2,446,708

Rate Design

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Current Rates Without Riders	Proposed Rates Without Riders	Proposed Rates With Riders (ACR 4 & USR)
\$15.58/Bill	\$14.09/Bill	\$17.00/Bill	\$17.00/Bill
\$0.05049/kWh	\$0.03534/kWh	\$0.05102/kWh	\$0.06433/kWh
-8.0%	-8.0%		
	\$1.50/Bill		
	-\$0.01/Bill		
	\$0.00184/kWh		
	7.5%		
-0.28%	-0.28%		

Revenue Impacts

Current Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$5,790	\$5,836	\$5,876
\$86,448	\$86,211	\$86,467
(\$7,379)	(\$7,364)	(\$7,387)
\$616	\$621	\$626
(\$4)	(\$4)	(\$4)
\$4,501	\$4,489	\$4,502
\$9,190	\$9,169	\$9,198
(\$369)	(\$368)	(\$369)
\$98,793	\$98,591	\$98,908

Proposed Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$6,986	\$7,042	\$7,090
\$124,804	\$124,462	\$124,831
\$131,790	\$131,503	\$131,921

Change

\$32,997	\$32,913	\$33,013
33.4%	33.4%	33.4%

PPL Electric Utilities Corporation
Rate Schedule: LP-4 Large General Service at 12,470 Volts
Impact of Proposed Rates On Total Revenues

Billing Volumes

Customer Months
Annual Energy
Annual Demand

HTY	FTY	FPFTY
14,621	14,771	14,840
6,082,854,450	6,039,278,455	6,032,075,326
14,284,876	14,305,089	14,316,117

Rate Design

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Proposed Rates
\$169.80/Bill	\$235.00/Bill
\$2.547/kW	\$4.012/kW
-8.0%	
\$63.12/Bill	
-\$0.01/Bill	
\$123.10/Bill	
7.5%	
-0.28%	

Revenue Impacts

Current Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$2,482,646	\$2,508,168	\$2,519,763
\$36,383,579	\$36,435,060	\$36,463,150
(\$3,109,298)	(\$3,115,458)	(\$3,118,633)
\$922,878	\$932,365	\$936,675
(\$146)	(\$148)	(\$148)
\$4,018,396	\$4,027,411	\$4,031,977
\$42,336,628	\$42,444,112	\$42,497,721

Proposed Rates

Customer Charge
Energy Charge
Demand Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$3,435,935	\$3,471,257	\$3,487,304
\$57,310,923	\$57,392,015	\$57,436,262
\$60,746,858	\$60,863,272	\$60,923,566

Change

\$18,410,229	\$18,419,160	\$18,425,845
43.5%	43.4%	43.4%

PPL Electric Utilities Corporation
Rate Schedule: LP-5 Large General Service at 69,000 Volts or Higher
Impact of Proposed Rates On Total Revenues

Billing Volumes	HTY	FTY	FPFTY
Customer Months	1,947	1,913	1,993
Annual Energy	6,068,124,552	6,447,545,100	12,100,437,658
Annual Demand	12,788,461	13,588,082	25,501,449

Rate Design	Current Rates	Proposed Rates
Customer Charge	\$994.00/Bill	\$997.92/Bill
Energy Charge		
Demand Charge		
TCJA	-8.0%	
SMR 2	\$63.12/Bill	
CER	-\$0.01/Bill	
SDER	\$101.50/Bill	
DSIC		
STAS-D	-0.28%	

Revenue Impacts

Current Rates	HTY	FTY	FPFTY
Customer Charge	\$1,935,318	\$1,901,136	\$1,981,334
Energy Charge			
Demand Charge			
TCJA	(\$154,825)	(\$152,091)	(\$158,507)
SMR 2	\$122,895	\$120,724	\$125,817
CER	(\$19)	(\$19)	(\$20)
SDER	\$197,621	\$194,130	\$202,319
DSIC			
STAS-D	(\$43,731)	(\$45,994)	(\$81,497)
Total	\$2,057,257	\$2,017,886	\$2,069,447
SDER			

Proposed Rates	HTY	FTY	FPFTY
Customer Charge	\$1,942,950	\$1,908,633	\$1,989,148
Energy Charge			
Demand Charge			
TCJA			
SMR 2			
CER			
SDER			
DSIC			
STAS-D			
Total	\$1,942,950	\$1,908,633	\$1,989,148

Change	(\$114,306)	(\$109,253)	(\$80,299)
	-5.6%	-5.4%	-3.9%

PPL Electric Utilities Corporation
Rate Schedule: SA Private Area Lighting Service
Impact of Proposed Rates On Total Revenues

Billing Volumes	HTY	FTY	FPFTY
HPS	32,397	32,335	32,172
LED	256,587	256,091	254,801

Rate Design	Current Rates	Proposed Rates
HPS	\$13.400/Lamp	\$16.018/Lamp
LED	\$13.400/Fixture	\$16.018/Fixture
TCJA	-8.0%	
SMR 2	\$0.00/Bill	
CER	-\$0.01/Bill	
SDER	\$0.60/Lamp (HSP) & \$014/Fixture (LED)	
DSIC	7.5%	
STAS-D	-0.28%	

Revenue Impacts

Current Rates	HTY	FTY	FPFTY
Charge per Light - HPS	\$434,123	\$433,283	\$431,101
Charge per Light - LED	\$3,438,263	\$3,431,617	\$3,414,333
TCJA	(\$309,791)	(\$309,192)	(\$307,635)
SMR 2			
CER	(\$2,890)	(\$2,884)	(\$2,870)
SDER	\$5,536	\$5,525	\$5,498
DSIC	\$268,158	\$267,640	\$266,292
STAS-D	(\$10,762)	(\$10,741)	(\$10,687)
Total	\$3,822,637	\$3,815,248	\$3,796,032

Proposed Rates	HTY	FTY	FPFTY
Charge per Light - HPS	\$518,938	\$517,935	\$515,327
Charge per Light - LED	\$4,110,007	\$4,102,063	\$4,081,402
TCJA			
SMR 2			
CER			
SDER			
DSIC			
STAS-D			
Total	\$4,628,946	\$4,619,998	\$4,596,728

Change	\$806,309	\$804,750	\$800,697
	21.1%	21.1%	21.1%

PPL Electric Utilities Corporation
Rate Schedule: SM(R) Mercury Vapor Street Lighting Service
Impact of Proposed Rates On Total Revenues

Billing Volumes	HTY	FTY	FPFTY
MV, OH, Wood- 3,350	6,492	5,794	5,353
MV, OH, Wood- 6,650	3,624	3,235	2,988
MV, OH, Wood- 10,500	96	86	79
MV, OH, Wood- 20,000	456	407	376
MV, OH, Wood- 34,000	36	32	30
MV, OH, Wood - 51,000	36	32	30
MV, OH, Metal- 3,350			
MV, OH, Metal- 6,650	36	32	30
MV, OH, Metal- 10,500	60	54	49
MV, OH, Metal- 20,000	60	54	49
MV, OH, Metal- 34,000	-	-	-
MV, OH, Metal - 51,000	-	-	-
MV, UG, Wood- 3,350	156	139	129
MV, UG, Wood- 6,650	1,512	1,350	1,247
MV, UG, Wood- 10,500			
MV, UG, Wood- 20,000			
MV, UG, Wood- 34,000			
MV, UG, Wood - 51,000			
MV, UG, Low- 3,350	2,496	2,228	2,058
MV, UG, Low- 6,650	1,980	1,767	1,633
MV, UG, Low- 10,500			
MV, UG, Low- 20,000			
MV, UG, Low- 34,000			
MV, UG, Low - 51,000			
MV, UG, High- 3,350			
MV, UG, High- 6,650	144	129	119
MV, UG, High- 10,500	-	-	-
MV, UG, High- 20,000	120	107	99
MV, UG, High- 34,000	72	64	59
MV, UG, High - 51,000	48	43	40
MV, Multiple- 3,350			
MV, Multiple- 6,650	60	54	49
MV, Multiple- 10,500	-	-	-
MV, Multiple- 20,000	36	32	30
MV, Multiple- 34,000	-	-	-
MV, Multiple - 51,000	-	-	-
Cust Owned - 3,350	1,140	1,018	940
Cust Owned - 6,650	276	246	228
Cust Owned - 10,500	-	-	-
Cust Owned - 20,000	48	43	40

PPL Electric Utilities Corporation
Rate Schedule: SM(R) Mercury Vapor Street Lighting Service
Impact of Proposed Rates On Total Revenues

Rate Design	Current Rates	Proposed Rates
MV, OH, Wood- 3,350	\$12.225/Lamp	\$14.612/Lamp
MV, OH, Wood- 6,650	\$14.641/Lamp	\$17.502/Lamp
MV, OH, Wood- 10,500	\$18.244/Lamp	\$21.813/Lamp
MV, OH, Wood- 20,000	\$22.788/Lamp	\$27.249/Lamp
MV, OH, Wood- 34,000	\$36.032/Lamp	\$43.093/Lamp
MV, OH, Wood - 51,000	\$45.252/Lamp	\$54.123/Lamp
MV, OH, Metal- 3,350		
MV, OH, Metal- 6,650	\$21.702/Lamp	\$25.950/Lamp
MV, OH, Metal- 10,500	\$25.127/Lamp	\$30.047/Lamp
MV, OH, Metal- 20,000	\$29.793/Lamp	\$35.629/Lamp
MV, OH, Metal- 34,000	\$43.255/Lamp	\$51.734/Lamp
MV, OH, Metal - 51,000	\$52.828/Lamp	\$63.186/Lamp
MV, UG, Wood- 3,350	\$18.503/Lamp	\$22.122/Lamp
MV, UG, Wood- 6,650	\$21.289/Lamp	\$25.455/Lamp
MV, UG, Wood- 10,500		
MV, UG, Wood- 20,000		
MV, UG, Wood- 34,000		
MV, UG, Wood - 51,000		
MV, UG, Low- 3,350	\$20.075/Lamp	\$24.003/Lamp
MV, UG, Low- 6,650	\$22.810/Lamp	\$27.275/Lamp
MV, UG, Low- 10,500		
MV, UG, Low- 20,000		
MV, UG, Low- 34,000		
MV, UG, Low - 51,000		
MV, UG, High- 3,350		
MV, UG, High- 6,650	\$25.232/Lamp	\$30.173/Lamp
MV, UG, High- 10,500	\$28.445/Lamp	\$34.016/Lamp
MV, UG, High- 20,000	\$33.357/Lamp	\$39.893/Lamp
MV, UG, High- 34,000	\$47.877/Lamp	\$57.263/Lamp
MV, UG, High - 51,000	\$57.425/Lamp	\$68.686/Lamp
MV, Multiple- 3,350		
MV, Multiple- 6,650	\$12.586/Lamp	\$15.044/Lamp
MV, Multiple- 10,500	\$16.818/Lamp	\$20.107/Lamp
MV, Multiple- 20,000	\$20.517/Lamp	\$24.532/Lamp
MV, Multiple- 34,000	\$33.951/Lamp	\$40.603/Lamp
MV, Multiple - 51,000	\$43.177/Lamp	\$51.640/Lamp
Cust Owned - 3,350	\$7.953/Lamp	\$9.501/Lamp
Cust Owned - 6,650	\$10.482/Lamp	\$12.527/Lamp
Cust Owned - 10,500	\$13.365/Lamp	\$15.976/Lamp
Cust Owned - 20,000	\$18.278/Lamp	\$21.853/Lamp
TCJA	-8.0%	
SMR 2		
CER	-\$0.01/Bill	
SDER	Varies	
DSIC	7.5%	
STAS-D	-0.28%	

PPL Electric Utilities Corporation
Rate Schedule: SM(R) Mercury Vapor Street Lighting Service
Impact of Proposed Rates On Total Revenues

Revenue Impacts

Current Rates

MV, OH, Wood- 3,350
MV, OH, Wood- 6,650
MV, OH, Wood- 10,500
MV, OH, Wood- 20,000
MV, OH, Wood- 34,000
MV, OH, Wood - 51,000
MV, OH, Metal- 3,350
MV, OH, Metal- 6,650
MV, OH, Metal- 10,500
MV, OH, Metal- 20,000
MV, OH, Metal- 34,000
MV, OH, Metal - 51,000
MV, UG, Wood- 3,350
MV, UG, Wood- 6,650
MV, UG, Wood- 10,500
MV, UG, Wood- 20,000
MV, UG, Wood- 34,000
MV, UG, Wood - 51,000
MV, UG, Low- 3,350
MV, UG, Low- 6,650
MV, UG, Low- 10,500
MV, UG, Low- 20,000
MV, UG, Low- 34,000
MV, UG, Low - 51,000
MV, UG, High- 3,350
MV, UG, High- 6,650
MV, UG, High- 10,500
MV, UG, High- 20,000
MV, UG, High- 34,000
MV, UG, High - 51,000
MV, Multiple- 3,350
MV, Multiple- 6,650
MV, Multiple- 10,500
MV, Multiple- 20,000
MV, Multiple- 34,000
MV, Multiple - 51,000
Cust Owned - 3,350
Cust Owned - 6,650
Cust Owned - 10,500
Cust Owned - 20,000

HTY	FTY	FPFTY
\$79,365	\$70,837	\$65,438
\$53,059	\$47,358	\$43,749
\$1,751	\$1,563	\$1,444
\$10,391	\$9,275	\$8,568
\$1,297	\$1,158	\$1,070
\$1,629	\$1,454	\$1,343
\$0	\$0	\$0
\$781	\$697	\$644
\$1,508	\$1,346	\$1,243
\$1,788	\$1,595	\$1,474
\$0	\$0	\$0
\$0	\$0	\$0
\$2,886	\$2,576	\$2,380
\$32,189	\$28,730	\$26,541
\$0	\$0	\$0
\$0	\$0	\$0
\$0	\$0	\$0
\$0	\$0	\$0
\$50,107	\$44,723	\$41,315
\$45,164	\$40,311	\$37,239
\$0	\$0	\$0
\$0	\$0	\$0
\$0	\$0	\$0
\$0	\$0	\$0
\$0	\$0	\$0
\$0	\$0	\$0
\$3,633	\$3,243	\$2,996
\$0	\$0	\$0
\$4,003	\$3,573	\$3,300
\$3,447	\$3,077	\$2,842
\$2,756	\$2,460	\$2,273
\$0	\$0	\$0
\$755	\$674	\$623
\$0	\$0	\$0
\$739	\$659	\$609
\$0	\$0	\$0
\$0	\$0	\$0
\$9,066	\$8,092	\$7,476
\$2,893	\$2,582	\$2,385
\$0	\$0	\$0
\$877	\$783	\$723
(\$24,807)	(\$22,141)	(\$20,454)
(\$190)	(\$169)	(\$157)
\$1,192	\$1,064	\$983
\$21,632	\$19,308	\$17,837
(\$868)	(\$775)	(\$716)
\$307,046	\$274,052	\$253,167

TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

PPL Electric Utilities Corporation
Rate Schedule: SM(R) Mercury Vapor Street Lighting Service
Impact of Proposed Rates On Total Revenues

Proposed Rates

	HTY	FTY	FPFTY
MV, OH, Wood- 3,350	\$94,861	\$84,668	\$78,216
MV, OH, Wood- 6,650	\$63,427	\$56,612	\$52,298
MV, OH, Wood- 10,500	\$2,094	\$1,869	\$1,727
MV, OH, Wood- 20,000	\$12,426	\$11,090	\$10,245
MV, OH, Wood- 34,000	\$1,551	\$1,385	\$1,279
MV, OH, Wood - 51,000	\$1,948	\$1,739	\$1,607
MV, OH, Metal- 3,350	\$0	\$0	\$0
MV, OH, Metal- 6,650	\$934	\$834	\$770
MV, OH, Metal- 10,500	\$1,803	\$1,609	\$1,486
MV, OH, Metal- 20,000	\$2,138	\$1,908	\$1,763
MV, OH, Metal- 34,000	\$0	\$0	\$0
MV, OH, Metal - 51,000	\$0	\$0	\$0
MV, UG, Wood- 3,350	\$3,451	\$3,080	\$2,845
MV, UG, Wood- 6,650	\$38,488	\$34,352	\$31,734
MV, UG, Wood- 10,500	\$0	\$0	\$0
MV, UG, Wood- 20,000	\$0	\$0	\$0
MV, UG, Wood- 34,000	\$0	\$0	\$0
MV, UG, Wood - 51,000	\$0	\$0	\$0
MV, UG, Low- 3,350	\$59,911	\$53,474	\$49,399
MV, UG, Low- 6,650	\$54,005	\$48,202	\$44,528
MV, UG, Low- 10,500	\$0	\$0	\$0
MV, UG, Low- 20,000	\$0	\$0	\$0
MV, UG, Low- 34,000	\$0	\$0	\$0
MV, UG, Low - 51,000	\$0	\$0	\$0
MV, UG, High- 3,350	\$0	\$0	\$0
MV, UG, High- 6,650	\$4,345	\$3,878	\$3,582
MV, UG, High- 10,500	\$0	\$0	\$0
MV, UG, High- 20,000	\$4,787	\$4,273	\$3,947
MV, UG, High- 34,000	\$4,123	\$3,680	\$3,399
MV, UG, High - 51,000	\$3,297	\$2,943	\$2,718
MV, Multiple- 3,350	\$0	\$0	\$0
MV, Multiple- 6,650	\$903	\$806	\$744
MV, Multiple- 10,500	\$0	\$0	\$0
MV, Multiple- 20,000	\$883	\$788	\$728
MV, Multiple- 34,000	\$0	\$0	\$0
MV, Multiple - 51,000	\$0	\$0	\$0
Cust Owned - 3,350	\$10,831	\$9,667	\$8,931
Cust Owned - 6,650	\$3,457	\$3,086	\$2,851
Cust Owned - 10,500	\$0	\$0	\$0
Cust Owned - 20,000	\$1,049	\$936	\$865
TCJA			
SMR 2			
CER			
SDER			
DSIC			
STAS-D			
Total	\$370,713	\$330,878	\$305,663
Change	\$63,667	\$56,826	\$52,495

20.7%	20.7%	20.7%

PPL Electric Utilities Corporation
Rate Schedule: SHS High Pressure Sodium Street Lighting Service
Impact of Proposed Rates On Total Revenues

Billing Volumes

HPS, OH, Wood- 5,800
HPS, OH, Wood- 9,500
HPS, OH, Wood- 16,000
HPS, OH, Wood- 25,500
HPS, OH, Wood- 50,000
HPS, OH, Metal- 5,800
HPS, OH, Metal- 9,500
HPS, OH, Metal- 16,000
HPS, OH, Metal- 25,500
HPS, OH, Metal- 50,000
HPS, UG, Wood- 5,800
HPS, UG, Wood- 9,500
HPS, UG, Wood- 16,000
HPS, UG, Wood- 25,500
HPS, UG, Wood- 50,000
Growth Rates
HPS, UG, Low- 9,500
HPS, UG, Low- 16,000
HPS, UG, Low- 25,500
HPS, UG, Low- 50,000
HPS, UG, High- 5,800
HPS, UG, High- 9,500
HPS, UG, High- 16,000
HPS, UG, High- 25,500
HPS, UG, High- 50,000
HPS, Multiple- 5,800
HPS, Multiple- 9,500
HPS, Multiple- 16,000
HPS, Multiple- 25,500
HPS, Multiple- 50,000

HTY	FTY	FPFTY
127,680	121,107	118,414
107,628	102,087	99,818
28,404	26,942	26,343
18,600	17,642	17,250
4,536	4,302	4,207
1,644	1,559	1,525
360	341	334
912	865	846
828	785	768
36	34	33
12,888	12,224	11,953
33,492	31,768	31,062
70,260	66,643	65,161
170,088	161,331	157,745
8,952	8,491	8,302
7,884	7,478	7,312
8,940	8,480	8,291
2,448	2,322	2,270
312	296	289
2,220	2,106	2,059
816	774	757
912	865	846
576	546	534

PPL Electric Utilities Corporation
Rate Schedule: SHS High Pressure Sodium Street Lighting Service
Impact of Proposed Rates On Total Revenues

Rate Design

HPS, OH, Wood- 5,800
HPS, OH, Wood- 9,500
HPS, OH, Wood- 16,000
HPS, OH, Wood- 25,500
HPS, OH, Wood- 50,000
HPS, OH, Metal- 5,800
HPS, OH, Metal- 9,500
HPS, OH, Metal- 16,000
HPS, OH, Metal- 25,500
HPS, OH, Metal- 50,000
HPS, UG, Wood- 5,800
HPS, UG, Wood- 9,500
HPS, UG, Wood- 16,000
HPS, UG, Wood- 25,500
HPS, UG, Wood- 50,000
HPS, UG, Low- 5,800
HPS, UG, Low- 9,500
HPS, UG, Low- 16,000
HPS, UG, Low- 25,500
HPS, UG, Low- 50,000
HPS, UG, High- 5,800
HPS, UG, High- 9,500
HPS, UG, High- 16,000
HPS, UG, High- 25,500
HPS, UG, High- 50,000
HPS, Multiple- 5,800
HPS, Multiple- 9,500
HPS, Multiple- 16,000
HPS, Multiple- 25,500
HPS, Multiple- 50,000

Current Rates	Proposed Rates
\$12.452/Lamp	\$14.884/Lamp
\$13.674/Lamp	\$16.345/Lamp
\$15.083/Lamp	\$18.031/Lamp
\$20.185/Lamp	\$24.135/Lamp
\$25.784/Lamp	\$30.833/Lamp
\$16.540/Lamp	\$19.774/Lamp
\$17.474/Lamp	\$20.891/Lamp
\$18.706/Lamp	\$22.365/Lamp
\$23.342/Lamp	\$27.911/Lamp
\$28.516/Lamp	\$34.101/Lamp
\$18.847/Lamp	\$22.534/Lamp
\$20.256/Lamp	\$24.220/Lamp
\$18.999/Lamp	\$22.716/Lamp
\$20.360/Lamp	\$24.344/Lamp
\$24.117/Lamp	\$28.839/Lamp
\$25.329/Lamp	\$30.289/Lamp
\$34.179/Lamp	\$40.876/Lamp
\$39.518/Lamp	\$47.263/Lamp
\$11.406/Lamp	\$13.632/Lamp
\$12.579/Lamp	\$15.035/Lamp
\$13.077/Lamp	\$15.631/Lamp
\$17.081/Lamp	\$20.421/Lamp
\$20.422/Lamp	\$24.418/Lamp
-8.0%	
-\$0.01/Bill	
Varies	
7.5%	
-0.28%	

TCJA
SMR 2
CER
SDER
DSIC
STAS-D

PPL Electric Utilities Corporation
Rate Schedule: SHS High Pressure Sodium Street Lighting Service
Impact of Proposed Rates On Total Revenues

Revenue Impacts

Current Rates

HPS, OH, Wood- 5,800
HPS, OH, Wood- 9,500
HPS, OH, Wood- 16,000
HPS, OH, Wood- 25,500
HPS, OH, Wood- 50,000
HPS, OH, Metal- 5,800
HPS, OH, Metal- 9,500
HPS, OH, Metal- 16,000
HPS, OH, Metal- 25,500
HPS, OH, Metal- 50,000
HPS, UG, Wood- 5,800
HPS, UG, Wood- 9,500
HPS, UG, Wood- 16,000
HPS, UG, Wood- 25,500
HPS, UG, Wood- 50,000
HPS, UG, Low- 5,800
HPS, UG, Low- 9,500
HPS, UG, Low- 16,000
HPS, UG, Low- 25,500
HPS, UG, Low- 50,000
HPS, UG, High- 5,800
HPS, UG, High- 9,500
HPS, UG, High- 16,000
HPS, UG, High- 25,500
HPS, UG, High- 50,000
HPS, Multiple- 5,800
HPS, Multiple- 9,500
HPS, Multiple- 16,000
HPS, Multiple- 25,500
HPS, Multiple- 50,000

TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$1,589,871	\$1,508,021	\$1,474,497
\$1,471,705	\$1,395,938	\$1,364,906
\$428,418	\$406,361	\$397,328
\$375,441	\$356,112	\$348,196
\$116,956	\$110,935	\$108,469
\$27,192	\$25,792	\$25,219
\$6,291	\$5,967	\$5,834
\$17,060	\$16,182	\$15,822
\$19,327	\$18,332	\$17,925
\$1,027	\$974	\$952
\$242,900	\$230,395	\$225,273
\$678,414	\$643,487	\$629,183
\$1,334,870	\$1,266,147	\$1,238,001
\$3,462,992	\$3,284,708	\$3,211,689
\$215,895	\$204,781	\$200,228
\$199,694	\$189,413	\$185,202
\$305,560	\$289,829	\$283,386
\$96,740	\$91,760	\$89,720
\$3,559	\$3,375	\$3,300
\$27,925	\$26,488	\$25,899
\$10,671	\$10,121	\$9,896
\$15,578	\$14,776	\$14,447
\$11,763	\$11,157	\$10,909
-\$852,788	-\$808,884	-\$790,903
-\$6,104	-\$5,790	-\$5,661
\$24,828	\$23,550	\$23,026
\$740,312	\$702,199	\$686,589
-\$29,711	-\$28,182	-\$27,555
\$10,536,385	\$9,993,944	\$9,771,778

PPL Electric Utilities Corporation
Rate Schedule: SHS High Pressure Sodium Street Lighting Service
Impact of Proposed Rates On Total Revenues

Proposed Rates

HPS, OH, Wood- 5,800
HPS, OH, Wood- 9,500
HPS, OH, Wood- 16,000
HPS, OH, Wood- 25,500
HPS, OH, Wood- 50,000
HPS, OH, Metal- 5,800
HPS, OH, Metal- 9,500
HPS, OH, Metal- 16,000
HPS, OH, Metal- 25,500
HPS, OH, Metal- 50,000
HPS, UG, Wood- 5,800
HPS, UG, Wood- 9,500
HPS, UG, Wood- 16,000
HPS, UG, Wood- 25,500
HPS, UG, Wood- 50,000
HPS, UG, Low- 5,800
HPS, UG, Low- 9,500
HPS, UG, Low- 16,000
HPS, UG, Low- 25,500
HPS, UG, Low- 50,000
HPS, UG, High- 5,800
HPS, UG, High- 9,500
HPS, UG, High- 16,000
HPS, UG, High- 25,500
HPS, UG, High- 50,000
HPS, Multiple- 5,800
HPS, Multiple- 9,500
HPS, Multiple- 16,000
HPS, Multiple- 25,500
HPS, Multiple- 50,000

TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$1,900,333	\$1,802,498	\$1,762,429
\$1,759,229	\$1,668,659	\$1,631,565
\$512,155	\$485,787	\$474,988
\$448,905	\$425,794	\$416,329
\$139,858	\$132,658	\$129,709
\$32,509	\$30,835	\$30,150
\$7,521	\$7,134	\$6,975
\$20,397	\$19,347	\$18,917
\$23,111	\$21,921	\$21,434
\$1,228	\$1,164	\$1,139
\$290,418	\$275,467	\$269,343
\$811,164	\$769,403	\$752,299
\$1,596,016	\$1,513,849	\$1,480,196
\$4,140,630	\$3,927,459	\$3,840,152
\$258,163	\$244,872	\$239,429
\$238,795	\$226,501	\$221,466
\$365,431	\$346,618	\$338,913
\$115,700	\$109,744	\$107,304
\$4,253	\$4,034	\$3,945
\$33,379	\$31,660	\$30,957
\$12,755	\$12,098	\$11,829
\$18,624	\$17,665	\$17,273
\$14,065	\$13,341	\$13,044
\$12,744,639	\$12,088,511	\$11,819,783

Change

\$2,208,254	\$2,094,567	\$2,048,005
21.0%	21.0%	21.0%

PPL Electric Utilities Corporation
Rate Schedule: SLE Light Emitting Diode (LED) Street Lighting Service
Impact of Proposed Rates On Total Revenues

Billing Volumes	HTY	FTY	FPFTY
LED, OH, Wood- 2,600			
LED, OH, Wood- 3,300	193,764	197,825	204,563
LED, OH, Wood- 3,800			
LED, OH, Wood- 4,900	254,076	259,402	268,236
LED, OH, Wood- 7,500	156	159	165
LED, OH, Wood - 15,000	44,928	45,870	47,432
LED, OH, Wood - 20,000	13,044	13,317	13,771
LED, OH, Metal- 2,600			
LED, OH, Metal- 3,300	24	25	25
LED, OH, Metal- 3,800			
LED, OH, Metal- 4,900	4,200	4,288	4,434
LED, OH, Metal- 7,500	696	711	735
LED, OH, Metal - 15,000	468	478	494
LED, OH, Metal - 20,000	48	49	51
LED, UG, Wood- 2,600	612	625	646
LED, UG, Wood- 3,300			
LED, UG, Wood- 3,800	3,216	3,283	3,395
LED, UG, Wood- 4,900			
LED, UG, Wood- 7,500			
LED, UG, Wood - 15,000			
LED, UG, Wood - 20,000			
LED, UG, Low- 2,600	11,040	11,271	11,655
LED, UG, Low- 3,300			
LED, UG, Low- 3,800	29,004	29,612	30,620
LED, UG, Low- 4,900			
LED, UG, Low- 7,500			
LED, UG, Low - 15,000			
LED, UG, Low - 20,000			
LED, UG, High- 2,600			
LED, UG, High- 3,300			
LED, UG, High- 3,800			
LED, UG, High- 4,900	8,208	8,380	8,665
LED, UG, High- 7,500	4,452	4,545	4,700
LED, UG, High - 15,000	5,484	5,599	5,790
LED, UG, High - 20,000	1,500	1,531	1,584
LED, Multiple- 2,600			
LED, Multiple- 3,300	132	135	139
LED, Multiple- 3,800			
LED, Multiple- 4,900	828	845	874
LED, Multiple- 7,500	420	429	443
LED, Multiple - 15,000	468	478	494
LED, Multiple - 20,000	168	172	177

PPL Electric Utilities Corporation
Rate Schedule: SLE Light Emitting Diode (LED) Street Lighting Service
Impact of Proposed Rates On Total Revenues

Rate Design	Current Rates	Proposed Rates
LED, OH, Wood- 2,600		
LED, OH, Wood- 3,300	\$13.026/Lamp	\$15.557/Lamp
LED, OH, Wood- 3,800		
LED, OH, Wood- 4,900	\$14.240/Lamp	\$17.009/Lamp
LED, OH, Wood- 7,500	\$16.056/Lamp	\$19.179/Lamp
LED, OH, Wood - 15,000	\$22.587/Lamp	\$26.986/Lamp
LED, OH, Wood - 20,000	\$28.936/Lamp	\$34.575/Lamp
LED, OH, Metal- 2,600		
LED, OH, Metal- 3,300	\$16.164/Lamp	\$19.308/Lamp
LED, OH, Metal- 3,800		
LED, OH, Metal- 4,900	\$17.149/Lamp	\$20.486/Lamp
LED, OH, Metal- 7,500	\$19.020/Lamp	\$22.722/Lamp
LED, OH, Metal - 15,000	\$25.414/Lamp	\$30.365/Lamp
LED, OH, Metal - 20,000	\$30.947/Lamp	\$36.979/Lamp
LED, UG, Wood- 2,600	\$24.695/Lamp	\$29.506/Lamp
LED, UG, Wood- 3,300		
LED, UG, Wood- 3,800	\$25.725/Lamp	\$30.737/Lamp
LED, UG, Wood- 4,900		
LED, UG, Wood- 7,500		
LED, UG, Wood - 15,000		
LED, UG, Wood - 20,000		
LED, UG, Low- 2,600	\$24.834/Lamp	\$29.672/Lamp
LED, UG, Low- 3,300		
LED, UG, Low- 3,800	\$25.801/Lamp	\$30.828/Lamp
LED, UG, Low- 4,900		
LED, UG, Low- 7,500		
LED, UG, Low - 15,000		
LED, UG, Low - 20,000		
LED, UG, High- 2,600		
LED, UG, High- 3,300		
LED, UG, High- 3,800		
LED, UG, High- 4,900	\$22.248/Lamp	\$26.581/Lamp
LED, UG, High- 7,500	\$23.943/Lamp	\$28.607/Lamp
LED, UG, High - 15,000	\$33.305/Lamp	\$39.797/Lamp
LED, UG, High - 20,000	\$39.842/Lamp	\$47.611/Lamp
LED, Multiple- 2,600		
LED, Multiple- 3,300	\$4.495/Lamp	\$5.360/Lamp
LED, Multiple- 3,800		
LED, Multiple- 4,900	\$4.730/Lamp	\$5.641/Lamp
LED, Multiple- 7,500	\$5.502/Lamp	\$6.564/Lamp
LED, Multiple - 15,000	\$8.053/Lamp	\$9.613/Lamp
LED, Multiple - 20,000	\$10.051/Lamp	\$12.001/Lamp
TCJA	-8.0%	
SMR 2		
CER	-\$0.01/Bill	
SDER	Varies	
DSIC	7.5%	
STAS-D	-0.28%	

PPL Electric Utilities Corporation
Rate Schedule: SLE Light Emitting Diode (LED) Street Lighting Service
Impact of Proposed Rates On Total Revenues

Revenue Impacts

Current Rates

	HTY	FTY	FPFTY
LED, OH, Wood- 2,600	\$2,523,969.86	\$2,576,873.19	\$2,664,634.87
LED, OH, Wood- 3,300			
LED, OH, Wood- 3,800			
LED, OH, Wood- 4,900	\$3,618,042.24	\$3,693,877.71	\$3,819,681.71
LED, OH, Wood- 7,500	\$2,504.74	\$2,557.24	\$2,644.33
LED, OH, Wood - 15,000	\$1,014,788.74	\$1,036,059.08	\$1,071,344.59
LED, OH, Wood - 20,000	\$377,441.18	\$385,352.49	\$398,476.60
LED, OH, Metal- 2,600			
LED, OH, Metal- 3,300	\$387.94	\$396.07	\$409.56
LED, OH, Metal- 3,800			
LED, OH, Metal- 4,900	\$72,025.80	\$73,535.49	\$76,039.92
LED, OH, Metal- 7,500	\$13,237.92	\$13,515.39	\$13,975.69
LED, OH, Metal - 15,000	\$11,893.75	\$12,143.05	\$12,556.61
LED, OH, Metal - 20,000	\$1,485.46	\$1,516.59	\$1,568.24
LED, UG, Wood- 2,600	\$15,113.34	\$15,430.12	\$15,955.63
LED, UG, Wood- 3,300			
LED, UG, Wood- 3,800	\$82,731.60	\$84,465.68	\$87,342.37
LED, UG, Wood- 4,900			
LED, UG, Wood- 7,500			
LED, UG, Wood - 15,000			
LED, UG, Wood - 20,000			
LED, UG, Low- 2,600	\$274,167.36	\$279,914.01	\$289,447.16
LED, UG, Low- 3,300			
LED, UG, Low- 3,800	\$748,332.20	\$764,017.52	\$790,037.99
LED, UG, Low- 4,900			
LED, UG, Low- 7,500			
LED, UG, Low - 15,000			
LED, UG, Low - 20,000			
LED, UG, High- 2,600			
LED, UG, High- 3,300			
LED, UG, High- 3,800			
LED, UG, High- 4,900	\$182,611.58	\$186,439.19	\$192,788.83
LED, UG, High- 7,500	\$106,594.24	\$108,828.49	\$112,534.91
LED, UG, High - 15,000	\$182,644.62	\$186,472.92	\$192,823.71
LED, UG, High - 20,000	\$59,763.00	\$61,015.65	\$63,093.69
LED, Multiple- 2,600			
LED, Multiple- 3,300	\$593.34	\$605.78	\$626.41
LED, Multiple- 3,800			
LED, Multiple- 4,900	\$3,916.44	\$3,998.53	\$4,134.71
LED, Multiple- 7,500	\$2,310.84	\$2,359.28	\$2,439.63
LED, Multiple - 15,000	\$3,768.80	\$3,847.80	\$3,978.85
LED, Multiple - 20,000	\$1,688.57	\$1,723.96	\$1,782.67
TCJA	(\$744,001)	(\$759,596)	(\$785,465)
SMR 2			
CER	(\$5,769)	(\$5,890)	(\$6,091)
SDER	\$14,797	\$15,107	\$15,622
DSIC	\$644,383	\$657,889	\$680,295
STAS-D	(\$25,861)	(\$26,403)	(\$27,303)
Total	\$9,183,562	\$9,376,053	\$9,695,377

PPL Electric Utilities Corporation
Rate Schedule: SLE Light Emitting Diode (LED) Street Lighting Service
Impact of Proposed Rates On Total Revenues

Proposed Rates	HTY	FTY	FPFTY
LED, OH, Wood- 2,600			
LED, OH, Wood- 3,300	\$3,014,386.55	\$3,077,569.18	\$3,182,383.29
LED, OH, Wood- 3,800			
LED, OH, Wood- 4,900	\$4,321,578.68	\$4,412,160.54	\$4,562,427.40
LED, OH, Wood- 7,500	\$2,991.92	\$3,054.64	\$3,158.67
LED, OH, Wood - 15,000	\$1,212,427.01	\$1,237,839.92	\$1,279,997.57
LED, OH, Wood - 20,000	\$450,996.30	\$460,449.35	\$476,131.07
LED, OH, Metal- 2,600			
LED, OH, Metal- 3,300	\$463.39	\$473.10	\$489.22
LED, OH, Metal- 3,800			
LED, OH, Metal- 4,900	\$86,041.20	\$87,844.65	\$90,836.42
LED, OH, Metal- 7,500	\$15,814.51	\$16,145.99	\$16,695.88
LED, OH, Metal - 15,000	\$14,210.82	\$14,508.68	\$15,002.81
LED, OH, Metal - 20,000	\$1,774.99	\$1,812.20	\$1,873.92
LED, UG, Wood- 2,600	\$18,057.67	\$18,436.17	\$19,064.06
LED, UG, Wood- 3,300			
LED, UG, Wood- 3,800	\$98,850.19	\$100,922.13	\$104,359.28
LED, UG, Wood- 4,900			
LED, UG, Wood- 7,500			
LED, UG, Wood - 15,000			
LED, UG, Wood - 20,000			
LED, UG, Low- 2,600	\$327,578.88	\$334,445.05	\$345,835.39
LED, UG, Low- 3,300			
LED, UG, Low- 3,800	\$894,135.31	\$912,876.71	\$943,966.95
LED, UG, Low- 4,900			
LED, UG, Low- 7,500			
LED, UG, Low - 15,000			
LED, UG, Low - 20,000			
LED, UG, High- 2,600			
LED, UG, High- 3,300			
LED, UG, High- 3,800			
LED, UG, High- 4,900	\$218,176.85	\$222,749.91	\$230,336.20
LED, UG, High- 7,500	\$127,358.36	\$130,027.84	\$134,456.26
LED, UG, High - 15,000	\$218,246.75	\$222,821.28	\$230,410.00
LED, UG, High - 20,000	\$71,416.50	\$72,913.42	\$75,396.66
LED, Multiple- 2,600			
LED, Multiple- 3,300	\$707.52	\$722.35	\$746.95
LED, Multiple- 3,800			
LED, Multiple- 4,900	\$4,670.75	\$4,768.65	\$4,931.06
LED, Multiple- 7,500	\$2,756.88	\$2,814.67	\$2,910.53
LED, Multiple - 15,000	\$4,498.88	\$4,593.18	\$4,749.61
LED, Multiple - 20,000	\$2,016.17	\$2,058.43	\$2,128.53
TCJA			
SMR 2			
CER			
SDER			
DSIC			
STAS-D			
Total	\$11,109,156	\$11,342,008	\$11,728,288
Change	\$1,925,594	\$1,965,955	\$2,032,911
	21.0%	21.0%	21.0%

PPL Electric Utilities Corporation
Rate Schedule: SE Energy Only Street Lighting Service
Impact of Proposed Rates On Total Revenues

Billing Volumes

Bills - Utility Poles
Bills - Customer Poles
Energy - Utility Pole
Energy - Customer Pole

HTY	FTY	FPFTY
550	540	531
814	801	787
10,367,195	10,648,696	10,558,673
15,359,232	15,776,281	15,642,910

Rate Design

Energy - Company Pole
Energy - Customer Pole
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Proposed Rates
\$0.10437/kWh	\$0.12597/kWh
\$0.06026/kWh	\$0.07320/kWh
-8.0%	
-\$0.01/Bill	
\$0.00092/kWh	
7.5%	
-0.28%	

Revenue Impacts

Current Rates

Energy - Company Pole
Energy - Customer Pole
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$1,082,024	\$1,111,404	\$1,102,009
\$925,547	\$950,679	\$942,642
(\$160,606)	(\$164,967)	(\$163,572)
(\$5)	(\$5)	(\$5)
\$23,668	\$24,311	\$24,105
\$143,500	\$147,397	\$146,150
(\$5,759)	(\$5,916)	(\$5,866)
\$2,008,370	\$2,062,903	\$2,045,464

Proposed Rates

Energy - Company Pole
Energy - Customer Pole
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$1,305,956	\$1,341,416	\$1,330,076
\$1,124,296	\$1,154,824	\$1,145,061
\$2,430,251	\$2,496,240	\$2,475,137

Change

\$421,882	\$433,337	\$429,673
21.0%	21.0%	21.0%

PPL Electric Utilities Corporation
Rate Schedule: TS (R) Municipal Traffic Signal Lighting Service
Impact of Proposed Rates On Total Revenues

Billing Volumes
Customer Months
Connected Watt - Months

HTY	FTY	FPFTY
1,020	1,008	1,008
410,628	410,628	410,628

Rate Design

Per Watt Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D

Current Rates	Proposed Rates
\$0.07496/watt	\$0.09049/watt
-8.0%	
-\$0.01/Bill	
\$0.00067/watt	
7.5%	
-0.28%	

Revenue Impacts

Current Rates

Per Watt Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-D
Total

HTY	FTY	FPFTY
\$30,781	\$30,781	\$30,781
(\$2,462)	(\$2,462)	(\$2,462)
\$0	\$0	\$0
(\$10)	(\$10)	(\$10)
\$275	\$275	\$275
\$2,181	\$2,181	\$2,181
(\$88)	(\$88)	(\$88)
\$31,261	\$31,261	\$31,261

Proposed Rates

Per Watt Charge
TCJA
SMR 2
CER
SDER
DSIC
STAS-T
Total

HTY	FTY	FPFTY
\$37,158	\$37,158	\$37,158
\$37,158	\$37,158	\$37,158

Change

\$5,897	\$5,897	\$5,897
18.9%	18.9%	18.9%

	Current Revenue	Proposed Revenue
RS Residential Service	\$789,757,365	\$1,004,694,742
GS-1 Single Phase General Service	\$86,712,902	\$114,574,119
GS-1 Volunteer / Non-Profit	\$828,990	\$1,090,164
GS-3 Three Phase General Service	\$138,034,376	\$176,698,011
GS-3 Volunteer / Non-Profit	\$98,908	\$131,921
LP-4 Large General Service at 12,470 Volts	\$42,497,721	\$60,923,566
LP-5 Large General Service at 69,000 Volts or Higher	\$2,069,447	\$1,989,148
SA Private Area Lighting Service	\$3,796,032	\$4,596,728
SM(R) Mercury Vapor Street Lighting Service	\$253,167	\$305,663
SHS High Pressure Sodium Street Lighting Service	\$9,771,778	\$11,819,783
SLE Light Emitting Diode (LED) Street Lighting Service	\$9,695,377	\$11,728,288
SE Energy Only Street Lighting Service	\$2,045,464	\$2,475,137
TS (R) Municipal Traffic Signal Lighting Service	\$31,261	\$37,158
<u>Incremental Revenue BL Borderline Service</u>		<u>\$136,518</u>
Total	\$1,085,592,788	\$1,391,200,945
	ACOSS Allocated Revenue Requirement	\$1,391,110,665
	Error Due to Rate Rounding	\$90,281

**PPL Electric Utilities Corporation
Rate Schedule: RS Residential Service
Current Rates vs Proposed Rates**

		Monthly Usage																
kWh		0	50	100	250	500	750	900	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	6,000
Current Rates																		
Customer Charge	\$15.58/Bill	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58	\$15.58
Energy Charge	\$0.05049/kWh	\$0.00	\$2.52	\$5.05	\$12.62	\$25.25	\$37.87	\$45.44	\$50.49	\$75.74	\$100.98	\$126.23	\$151.47	\$176.72	\$201.96	\$227.21	\$252.45	\$302.94
Riders																		
TCJA	-8.0%	-\$1.25	-\$1.45	-\$1.65	-\$2.26	-\$3.27	-\$4.28	-\$4.88	-\$5.29	-\$7.31	-\$9.32	-\$11.34	-\$13.36	-\$15.38	-\$17.40	-\$19.42	-\$21.44	-\$25.48
DSIC	7.5%	\$1.08	\$1.25	\$1.42	\$1.95	\$2.82	\$3.69	\$4.21	\$4.56	\$6.30	\$8.04	\$9.78	\$11.53	\$13.27	\$15.01	\$16.75	\$18.49	\$21.98
STATS-D	-0.28%	-\$0.04	-\$0.05	-\$0.06	-\$0.08	-\$0.11	-\$0.15	-\$0.17	-\$0.18	-\$0.25	-\$0.32	-\$0.39	-\$0.46	-\$0.53	-\$0.60	-\$0.67	-\$0.74	-\$0.88
Current Rates		\$15.37	\$17.86	\$20.34	\$27.81	\$40.26	\$52.71	\$60.18	\$65.16	\$90.06	\$114.96	\$139.85	\$164.75	\$189.65	\$214.54	\$239.44	\$264.34	\$314.13
Proposed Rate Design																		
Customer Charge	\$17.00/Bill	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00	\$17.00
Energy Charge	\$0.06433/kWh	\$0.00	\$3.22	\$6.43	\$16.08	\$32.17	\$48.25	\$57.90	\$64.33	\$96.50	\$128.66	\$160.83	\$192.99	\$225.16	\$257.32	\$289.49	\$321.65	\$385.98
Riders																		
TCJA	0.0%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
DSIC	0.0%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
STATS-D	0.0%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Proposed Rate Design		\$17.00	\$20.22	\$23.43	\$33.08	\$49.17	\$65.25	\$74.90	\$81.33	\$113.50	\$145.66	\$177.83	\$209.99	\$242.16	\$274.32	\$306.49	\$338.65	\$402.98
Difference		\$1.63	\$2.36	\$3.09	\$5.27	\$8.90	\$12.54	\$14.72	\$16.17	\$23.44	\$30.70	\$37.97	\$45.24	\$52.51	\$59.78	\$67.04	\$74.31	\$88.85
		10.6%	13.2%	15.2%	18.9%	22.1%	23.8%	24.5%	24.8%	26.0%	26.7%	27.2%	27.5%	27.7%	27.9%	28.0%	28.1%	28.3%

**PPL Electric Utilities Corporation
Rate Schedule: GS-1 Single Phase General Service
Current Rates vs Proposed Rates**

		<u>Monthly Usage</u>											
		0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
		100%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
		-	-	183	365	548	730	913	1,095	1,278	1,460	1,643	1,825
Current Rates													
Customer Charge	\$22.00/Bill	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00
Demand Charge	\$4.361/kW	\$0.00	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90	\$10.90
Riders													
TCJA	-8.0%	-\$1.76	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63	-\$2.63
SMR 2	\$3.03/Bill	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03
CER	-\$0.01/Bill	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01
ACR 4	\$0.00166/kWh	\$0.00	\$0.00	\$0.30	\$0.61	\$0.91	\$1.21	\$1.51	\$1.82	\$2.12	\$2.42	\$2.73	\$3.03
SDER	\$0.00092/kWh	\$0.00	\$0.00	\$0.17	\$0.34	\$0.50	\$0.67	\$0.84	\$1.01	\$1.18	\$1.34	\$1.51	\$1.68
DSIC	7.5%	\$1.74	\$2.50	\$2.53	\$2.57	\$2.60	\$2.64	\$2.67	\$2.71	\$2.74	\$2.78	\$2.81	\$2.85
STAS-D	-0.28%	-\$0.07	-\$0.10	-\$0.10	-\$0.10	-\$0.10	-\$0.11	-\$0.11	-\$0.11	-\$0.11	-\$0.11	-\$0.11	-\$0.11
Current Rates		\$24.93	\$35.69	\$36.19	\$36.70	\$37.20	\$37.71	\$38.21	\$38.72	\$39.22	\$39.72	\$40.23	\$40.73
Proposed Rate Design													
Customer Charge	\$30.00/Bill	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
Demand Charge	\$6.532/kW	\$0.00	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33	\$16.33
Riders													
ACR 4	\$0.00166/kWh	\$0.00	\$0.00	\$0.30	\$0.61	\$0.91	\$1.21	\$1.51	\$1.82	\$2.12	\$2.42	\$2.73	\$3.03
Proposed Rate Design		\$30.00	\$46.33	\$46.63	\$46.94	\$47.24	\$47.54	\$47.84	\$48.15	\$48.45	\$48.75	\$49.06	\$49.36
Difference		\$5.07	\$10.64	\$10.44	\$10.24	\$10.04	\$9.84	\$9.63	\$9.43	\$9.23	\$9.03	\$8.83	\$8.63
		20.3%	29.8%	28.9%	27.9%	27.0%	26.1%	25.2%	24.4%	23.5%	22.7%	21.9%	21.2%

**PPL Electric Utilities Corporation
Rate Schedule: GS-1 Single Phase General Service
Current Rates vs Proposed Rates**

<u>Monthly Usage</u>												
kW	5	5	5	5	5	5	5	5	5	5	5	5
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	365	730	1,095	1,460	1,825	2,190	2,555	2,920	3,285	3,650	
Current Rates												
Customer Charge	\$22.00/Bill	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00
Demand Charge	\$4.361/kW	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81	\$21.81
Riders												
TCJA	-8.0%	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50	-\$3.50
SMR 2	\$3.03/Bill	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03
CER	-\$0.01/Bill	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01
ACR 4	\$0.00166/kWh	\$0.00	\$0.61	\$1.21	\$1.82	\$2.42	\$3.03	\$3.64	\$4.24	\$4.85	\$5.45	\$6.06
SDER	\$0.00092/kWh	\$0.00	\$0.34	\$0.67	\$1.01	\$1.34	\$1.68	\$2.01	\$2.35	\$2.69	\$3.02	\$3.36
DSIC	7.5%	\$3.25	\$3.32	\$3.39	\$3.46	\$3.53	\$3.60	\$3.67	\$3.74	\$3.81	\$3.88	\$3.96
STAS-D	-0.28%	-\$0.13	-\$0.13	-\$0.14	-\$0.14	-\$0.14	-\$0.14	-\$0.15	-\$0.15	-\$0.15	-\$0.16	-\$0.16
Current Rates		\$46.44	\$47.45	\$48.46	\$49.47	\$50.48	\$51.49	\$52.50	\$53.51	\$54.52	\$55.52	\$56.53
Proposed Rate Design												
Customer Charge	\$30.00/Bill	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
Demand Charge	\$6.532/kW	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66	\$32.66
Riders												
ACR 4	\$0.00166/kWh	\$0.00	\$0.61	\$1.21	\$1.82	\$2.42	\$3.03	\$3.64	\$4.24	\$4.85	\$5.45	\$6.06
Proposed Rate Design		\$62.66	\$63.27	\$63.87	\$64.48	\$65.08	\$65.69	\$66.30	\$66.90	\$67.51	\$68.11	\$68.72
Difference		\$16.22	\$15.82	\$15.41	\$15.01	\$14.61	\$14.20	\$13.80	\$13.40	\$12.99	\$12.59	\$12.18
		34.9%	33.3%	31.8%	30.3%	28.9%	27.6%	26.3%	25.0%	23.8%	22.7%	21.6%

PPL Electric Utilities Corporation
Rate Schedule: GS-1 Single Phase General Service
Current Rates vs Proposed Rates

	<u>Monthly Usage</u>											
	10	10	10	10	10	10	10	10	10	10	10	10
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	730	1,460	2,190	2,920	3,650	4,380	5,110	5,840	6,570	7,300	
Current Rates												
Customer Charge	\$22.00/Bill	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00	\$22.00
Demand Charge	\$4.361/kW	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61	\$43.61
Riders												
TCJA	-8.0%	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25	-\$5.25
SMR 2	\$3.03/Bill	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03
CER	-\$0.01/Bill	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01
ACR 4	\$0.00166/kWh	\$0.00	\$1.21	\$2.42	\$3.64	\$4.85	\$6.06	\$7.27	\$8.48	\$9.69	\$10.91	\$12.12
SDER	\$0.00092/kWh	\$0.00	\$0.67	\$1.34	\$2.01	\$2.69	\$3.36	\$4.03	\$4.70	\$5.37	\$6.04	\$6.72
DSIC	7.5%	\$4.75	\$4.89	\$5.04	\$5.18	\$5.32	\$5.46	\$5.60	\$5.74	\$5.88	\$6.02	\$6.17
STAS-D	-0.28%	-\$0.19	-\$0.20	-\$0.20	-\$0.21	-\$0.21	-\$0.22	-\$0.22	-\$0.23	-\$0.24	-\$0.24	-\$0.25
Current Rates		\$67.94	\$69.96	\$71.98	\$74.00	\$76.02	\$78.04	\$80.06	\$82.08	\$84.10	\$86.11	\$88.13
Proposed Rate Design												
Customer Charge	\$30.00/Bill	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00	\$30.00
Demand Charge	\$6.532/kW	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32	\$65.32
Riders												
ACR 4	\$0.00166/kWh	\$0.00	\$1.21	\$2.42	\$3.64	\$4.85	\$6.06	\$7.27	\$8.48	\$9.69	\$10.91	\$12.12
Proposed Rate Design		\$95.32	\$96.53	\$97.74	\$98.96	#####	#####	#####	#####	#####	#####	\$107.44
Difference		\$27.38	\$26.57	\$25.76	\$24.95	\$24.15	\$23.34	\$22.53	\$21.73	\$20.92	\$20.11	\$19.30
		40.3%	38.0%	35.8%	33.7%	31.8%	29.9%	28.1%	26.5%	24.9%	23.4%	21.9%

**PPL Electric Utilities Corporation
Rate Schedule: GS-3 Three Phase General Service
Current Rates vs Proposed Rates**

		<u>Monthly Usage</u>											
kW		0	25	25	25	25	25	25	25	25	25	25	25
LF%		100%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
kWh		-	-	1,825	3,650	5,475	7,300	9,125	10,950	12,775	14,600	16,425	18,250
Current Rates													
Customer Charge	\$60.00/Bill	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00
Demand Charge	\$3.985/kW	\$0.00	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63	\$99.63
Riders													
TCJA	-8.0%	-\$4.80	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77	-\$12.77
SMR 2	\$3.03/Bill	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03
CER	-\$0.01/Bill	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01
ACR 4	\$0.00166/kWh	\$0.00	\$0.00	\$3.03	\$6.06	\$9.09	\$12.12	\$15.15	\$18.18	\$21.21	\$24.24	\$27.27	\$30.30
SDER	\$0.00092/kWh	\$0.00	\$0.00	\$1.68	\$3.36	\$5.04	\$6.72	\$8.40	\$10.07	\$11.75	\$13.43	\$15.11	\$16.79
DSIC	7.5%	\$4.37	\$11.24	\$11.59	\$11.95	\$12.30	\$12.65	\$13.01	\$13.36	\$13.71	\$14.07	\$14.42	\$14.77
STAS-D	-0.28%	-\$0.18	-\$0.45	-\$0.47	-\$0.48	-\$0.49	-\$0.51	-\$0.52	-\$0.54	-\$0.55	-\$0.56	-\$0.58	-\$0.59
Current Rates		\$62.41	\$160.66	\$165.71	\$170.76	\$175.81	\$180.85	\$185.90	\$190.95	\$196.00	\$201.04	\$206.09	\$211.14
Proposed Rate Design													
Customer Charge	\$78.00/Bill	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00
Demand Charge	\$5.529/kW	\$0.00	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23	\$138.23
Riders													
ACR 4	\$0.00166/kWh	\$0.00	\$0.00	\$3.03	\$6.06	\$9.09	\$12.12	\$15.15	\$18.18	\$21.21	\$24.24	\$27.27	\$30.30
Proposed Rate Design		\$78.00	\$216.23	\$219.25	\$222.28	\$225.31	\$228.34	\$231.37	\$234.40	\$237.43	\$240.46	\$243.49	\$246.52
Difference		\$15.59	\$55.56	\$53.54	\$51.52	\$49.51	\$47.49	\$45.47	\$43.45	\$41.43	\$39.42	\$37.40	\$35.38
		25.0%	34.6%	32.3%	30.2%	28.2%	26.3%	24.5%	22.8%	21.1%	19.6%	18.1%	16.8%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Three Phase General Service
Current Rates vs Proposed Rates

<u>Monthly Usage</u>												
kW	50	50	50	50	50	50	50	50	50	50	50	50
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	3,650	7,300	10,950	14,600	18,250	21,900	25,550	29,200	32,850	36,500	
Current Rates												
Customer Charge	\$60.00/Bill	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00
Demand Charge	\$3.985/kW	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25	\$199.25
Riders												
TCJA	-8.0%	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74	-\$20.74
SMR 2	\$3.03/Bill	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03
CER	-\$0.01/Bill	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01
ACR 4	\$0.00166/kWh	\$0.00	\$6.06	\$12.12	\$18.18	\$24.24	\$30.30	\$36.35	\$42.41	\$48.47	\$54.53	\$60.59
SDER	\$0.00092/kWh	\$0.00	\$3.36	\$6.72	\$10.07	\$13.43	\$16.79	\$20.15	\$23.51	\$26.86	\$30.22	\$33.58
DSIC	7.5%	\$18.11	\$18.82	\$19.53	\$20.23	\$20.94	\$21.65	\$22.35	\$23.06	\$23.76	\$24.47	\$25.18
STAS-D	-0.28%	-\$0.73	-\$0.76	-\$0.78	-\$0.81	-\$0.84	-\$0.87	-\$0.90	-\$0.93	-\$0.95	-\$0.98	-\$1.01
Current Rates		\$258.92	\$269.01	\$279.11	\$289.20	\$299.30	\$309.39	\$319.49	\$329.58	\$339.68	\$349.77	\$359.87
Proposed Rate Design												
Customer Charge	\$78.00/Bill	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00
Demand Charge	\$5.529/kW	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45	\$276.45
Riders												
ACR 4	\$0.00166/kWh	\$0.00	\$6.06	\$12.12	\$18.18	\$24.24	\$30.30	\$36.35	\$42.41	\$48.47	\$54.53	\$60.59
Proposed Rate Design		\$354.45	\$360.51	\$366.57	\$372.63	\$378.69	\$384.75	\$390.80	\$396.86	\$402.92	\$408.98	\$415.04
Difference		\$95.53	\$91.50	\$87.46	\$83.42	\$79.39	\$75.35	\$71.32	\$67.28	\$63.24	\$59.21	\$55.17
		36.9%	34.0%	31.3%	28.8%	26.5%	24.4%	22.3%	20.4%	18.6%	16.9%	15.3%

PPL Electric Utilities Corporation
Rate Schedule: GS-3 Three Phase General Service
Current Rates vs Proposed Rates

		<u>Monthly Usage</u>										
kW		100	100	100	100	100	100	100	100	100	100	100
LF%		0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
kWh		-	7,300	14,600	21,900	29,200	36,500	43,800	51,100	58,400	65,700	73,000
Current Rates												
Customer Charge	\$60.00/Bill	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00	\$60.00
Demand Charge	\$3.985/kW	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50	\$398.50
Riders												
TCJA	-8.0%	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68	-\$36.68
SMR 2	\$3.03/Bill	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03	\$3.03
CER	-\$0.01/Bill	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01	-\$0.01
ACR 4	\$0.00166/kWh	\$0.00	\$12.12	\$24.24	\$36.35	\$48.47	\$60.59	\$72.71	\$84.83	\$96.94	\$109.06	\$121.18
SDER	\$0.00092/kWh	\$0.00	\$6.72	\$13.43	\$20.15	\$26.86	\$33.58	\$40.30	\$47.01	\$53.73	\$60.44	\$67.16
DSIC	7.5%	\$31.86	\$33.28	\$34.69	\$36.10	\$37.51	\$38.93	\$40.34	\$41.75	\$43.16	\$44.58	\$45.99
STAS-D	-0.28%	-\$1.28	-\$1.34	-\$1.39	-\$1.45	-\$1.51	-\$1.56	-\$1.62	-\$1.68	-\$1.73	-\$1.79	-\$1.85
Current Rates		\$455.42	\$475.61	\$495.80	\$515.99	\$536.18	\$556.37	\$576.56	\$596.75	\$616.94	\$637.13	\$657.32
Proposed Rate Design												
Customer Charge	\$78.00/Bill	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00	\$78.00
Demand Charge	\$5.529/kW	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90	\$552.90
Riders												
ACR 4	\$0.00166/kWh	\$0.00	\$12.12	\$24.24	\$36.35	\$48.47	\$60.59	\$72.71	\$84.83	\$96.94	\$109.06	\$121.18
Proposed Rate Design		\$630.90	\$643.02	\$655.14	\$667.25	\$679.37	\$691.49	\$703.61	\$715.73	\$727.84	\$739.96	\$752.08
Difference		\$175.48	\$167.40	\$159.33	\$151.26	\$143.19	\$135.12	\$127.04	\$118.97	\$110.90	\$102.83	\$94.76
		38.5%	35.2%	32.1%	29.3%	26.7%	24.3%	22.0%	19.9%	18.0%	16.1%	14.4%

PPL Electric Utilities Corporation
Rate Schedule: LP-4 Large General Service at 12,470 Volts
Current Rates vs Proposed Rates

	Monthly Usage											
kW	0	500	500	500	500	500	500	500	500	500	500	500
LF%	100%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
kWh	-	-	36,500	73,000	109,500	146,000	182,500	219,000	255,500	292,000	328,500	365,000

Current Rates

[illegible]

Proposed Rate Design

[illegible]

PPL Electric Utilities Corporation
Rate Schedule: LP-4 Large General Service at 12,470 Volts
Current Rates vs Proposed Rates

	Monthly Usage											
kW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	100%
kWh	-	73,000	146,000	219,000	292,000	365,000	438,000	511,000	584,000	657,000	730,000	730,000

Current Rates

[illegible]

Proposed Rate Design

[illegible][illegible]

PPL Electric Utilities Corporation
Rate Schedule: LP-4 Large General Service at 12,470 Volts
Current Rates vs Proposed Rates

	Monthly Usage											
kW	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	146,000	292,000	438,000	584,000	730,000	876,000	1,022,000	1,168,000	1,314,000	1,460,000	

Current Rates

[illegible]

Proposed Rate Design

[illegible]

PPL Electric Utilities Corporation
Rate Schedule: LP-5 Large General Service at 69,000 Volts or Higher
Current Rates vs Proposed Rates

Monthly Usage													
kW	-	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
LF%	100%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	-	365,000	730,000	1,095,000	1,460,000	1,825,000	2,190,000	2,555,000	2,920,000	3,285,000	3,650,000	

Current Rates

[illegible]

Proposed Rate Design

[illegible]

PPL Electric Utilities Corporation
Rate Schedule: LP-5 Large General Service at 69,000 Volts or Higher
Current Rates vs Proposed Rates

	Monthly Usage											
kW	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	730,000	1,460,000	2,190,000	2,920,000	3,650,000	4,380,000	5,110,000	5,840,000	6,570,000	7,300,000	

Current Rates

[illegible]

Proposed Rate Design

[illegible]

PPL Electric Utilities Corporation
Rate Schedule: LP-5 Large General Service at 69,000 Volts or Higher
Current Rates vs Proposed Rates

	Monthly Usage											
kW	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
LF%	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
kWh	-	1,460,000	2,920,000	4,380,000	5,840,000	7,300,000	8,760,000	10,220,000	11,680,000	13,140,000	14,600,000	

Current Rates

[illegible]

Proposed Rate Design

[illegible]

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
JULISSA BURGOS
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Embedded Cost of Capital
 Capital Structure**

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Julissa Burgos. My business address is Two City Center, 645 Hamilton Street, Suite 9, Allentown, PA 18101.

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

A. I am employed by PPL Services Corporation (“PPL Services”), a subsidiary of PPL Corporation and an affiliate of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”), which provides services to PPL Corporation and its subsidiaries. I hold the position of Assistant Treasurer. I also serve as Assistant Treasurer for PPL Electric.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric Statement No. 9, concerning PPL Electric’s capital structure, embedded cost of capital, and return on common equity.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the various witnesses that addressed capital structure and its impact on credit ratings. These proposals were recommended by witnesses for the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation and Enforcement (“I&E”), the Office of Consumer Advocate (“OCA”), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (“CAUSE-

PA”), and the Energy Justice Advocates (“EJA”). Specifically, I address the hypothetical capital structures that are being proposed by the other parties as well as address the impact of credit quality on the Company’s cost of capital.

Q. Please summarize the key issues and recommendations offered by the opposing witnesses that you address in your rebuttal testimony.

A. I respond to several assertions made by the opposing witnesses regarding PPL Electric’s proposed capital structure and financial practices. The opposing witnesses argue that PPL Electric’s proposed equity ratio is out of step with industry standards based on broad averages reported by the Edison Electric Institute (“EEI”) and Regulatory Research Associates (“RRA”), such as investment needs, credit objectives, and regulatory requirements. In response, I explain that PPL Electric’s 56.05% equity ratio is well within the range of peer utilities and consistent with maintaining strong investment-grade credit ratings.

Certain opposing parties’ witnesses also claim that PPL Electric may manipulate its capital structure between rate cases. I rebut this assertion and clarify that the Company’s financing decisions are driven by legitimate business needs and sound financial management, not opportunistic behavior. I also demonstrate, using Schedule B-7 of Exhibit Fully Projected Future 1, that PPL Electric has maintained a consistent equity ratio of approximately 56% for several years, including periods between rate cases.

Finally, I recommend that the Commission reject the hypothetical capital structures proposed by opposing witnesses and, consistent with longstanding Commission precedent, adopt PPL Electric’s actual capital structure.

1
2 **Q. How is the remainder of your rebuttal testimony organized?**

3 A. Section II of my rebuttal testimony responds to the other parties' claims and assumptions
4 regarding cost of capital. Section III discusses and explains PPL Electric's capital structure
5 and addresses other parties' recommendations. Section IV is the Conclusion.
6

7 **II. EMBEDDED COST OF CAPITAL**

8 **Q. Did any party dispute the Company's cost of debt for purposes of calculating PPL**
9 **Electric's weighted average cost of capital?**

10 A. No. In fact, the only parties who directly addressed the issue, i.e., I&E and OCA, accepted
11 the Company's calculated cost of debt of 5.08%. (See I&E St. No. 3, p. 20; OCA Exh. DJG-
12 16.)
13

14 **Q. I&E Witness Breuning does allege, however, that "any concern over a potential credit**
15 **downgrade or access to capital markets is irrational," given PPL Electric's actual return**
16 **on equity trending upward over the past 10 years and S&P upgrading PPL Electric's**
17 **credit rating in 2022. (I&E St. No. 3, pp. 54-55.) Do you agree?**

18 A. No. I do not agree that concerns regarding potential credit downgrades or access to capital
19 markets are irrational. While I acknowledge that PPL Electric's financial metrics have been
20 stable and that S&P upgraded the Company's credit rating in 2022, that action was driven by
21 S&P's methodology, which allowed PPL Electric to be rated one notch above the group credit
22 profile due to its strong financial performance, supportive regulatory environment, and

1 sufficient insulation from its parent. However, the upgrade reflected conditions at that specific
2 point in time and does not guarantee the same assessment going forward. Credit quality
3 depends on various factors, including regulatory outcomes, capital investment requirements,
4 and broader economic conditions. Strong credit metrics are critical for the ability to access
5 lower-cost capital for infrastructure investments that ensure reliability and affordability for
6 customers. Therefore, maintaining strong credit ratings remains prudent and necessary, and
7 the Company's actual capital structure plays a significant role in maintaining the credit metrics
8 needed to support those strong credit ratings.

9
10 **Q. Mr. Breuning also claims that if the Federal Reserve cuts interest rates multiple times**
11 **in 2026, it “could have the effect of reducing debt cost rates in the capital costs in 2026,”**
12 **which is when PPL’s new rates will be effective. (I&E St. No. 3, pp. 53-54.) Please**
13 **respond.**

14 **A.** I do not agree with the statement that Federal Reserve rate cuts in 2026 would necessarily
15 reduce the Company's debt costs. Federal Reserve policy primarily impacts short-term
16 interest rates, while long-term rates are more heavily influenced by broader market factors,
17 such as inflation expectations, global geopolitical and economic conditions, and overall
18 investor sentiment. Rate cuts by the Federal Reserve do not always result in lower long-term
19 rates. Utilities typically issue long-term debt to match the life of the assets being financed.
20 The Company regularly monitors market conditions and evaluates the timing of accessing the
21 capital markets to achieve efficient execution of its transactions. As for existing long-term
22 debt, it contains early redemption provisions within the bond agreements that significantly

1 increase the cost of prepayment of the existing bonds outstanding, potentially making it not
2 cost beneficial for customers.

3
4 **III. CAPITAL STRUCTURE**

5 **Q. What capital structure has PPL Electric proposed to utilize to calculate its overall rate**
6 **of return in this proceeding?**

7 A. PPL Electric has proposed to use its actual capital structure of 56.05% equity and 43.95%
8 long-term debt.

9
10 **Q. Have other parties proposed using a hypothetical capital structure instead of PPL**
11 **Electric's actual capital structure?**

12 A. Yes. I&E, OCA, CAUSE-PA, and EJA have proposed the following hypothetical capital
13 structures:

- 14 • I&E – 55.00% equity and 45.00% long-term debt
- 15 • OCA – 42.00% equity and 58.00% long-term debt
- 16 • CAUSE-PA – impute the capital structure of PPL Corporation (44.00% equity and
17 56.00% long-term debt) or at least 50.00% equity and 50.00% long-term debt
- 18 • EJA – 50.00% equity and 50.00% long-term debt

19 (I&E St. No. 3, pp. 15-16; OCA St. 3, pp. 51-54, 59-60; CAUSE-PA St. No. 1, pp. 19-20;
20 EJA St. No. 1, pp. 6, 29.)

21

1 **Q. Before addressing their positions in more detail, do you have any overall issues with**
2 **their proposed hypothetical capital structures.**

3 A. Yes. No reason exists to impute a hypothetical capital structure for PPL Electric in this
4 proceeding. The Commission has long utilized a public utility's actual capital structure when
5 determining the weighted average cost of capital, including in PPL Electric's last fully
6 litigated rate case. *See Pa. PUC v. PPL Elec. Utils. Corp.*, Docket Nos. R-2012-2290597, *et*
7 *al.*, pp. 68-69 (Order entered Dec. 28, 2012) ("*PPL 2012 Order*"). In that order, the
8 Commission accepted PPL Electric's actual capital structure and rejected proposals by I&E
9 and OCA to use hypothetical capital structures. *See id.*, pp. 58-69. The Commission reasoned
10 as follows:

11 Upon our consideration of the evidence of record, the Recommended
12 Decision and the Exceptions and Reply Exceptions filed by the Parties,
13 we are persuaded by the position of PPL to adopt the Company's
14 actual capital structure and affirm the recommendation of the ALJ. It
15 is important to note that the actual capital structure represents the
16 Company's decision, in which it has full discretion, on how to
17 capitalize its rate base. This actual capitalization forms the basis upon
18 which PPL attracts capital. PPL's debt cost rate of 5.50%, which all
19 Parties have accepted for ratemaking purposes, fully reflects the
20 capitalization determined by the Company to be appropriate. Absent a
21 finding by the Commission that a utility's actual capital structure is
22 atypical or too heavily weighted on either the debt or equity side, we
23 would not normally exercise our discretion with regard to
24 implementing a hypothetical capital structure. *See, Pa. PUC v. City of*
25 *Lancaster —Water*, 1999 Pa. PUC Lexis 37 at * 17; *Carnegie Natural*
26 *Gas Co. v. Pa. PUC*, 433 A.2d 938, 940 (Pa. Cmwlth. 1981). With
27 regard to these factors, we are persuaded by the arguments of PPL that
28 its actual capital structure is not atypical, is within a range of
29 reasonableness, and, pursuant to precedent, provides no basis to
30 employ a hypothetical capital structure. Also, we are further swayed
31 by PPL's assertion that it requires an equity ratio near the high end of
32 the historic range employed by the barometer group companies to
33 support its expanded infrastructure replacement program and its credit
34 rating.

1 *Id.*, p. 68 (emphasis added). The Commission should follow this precedent and once again
2 utilize PPL Electric’s actual capital structure in this proceeding.

3 In addition, the Commission recently and strongly reaffirmed its long-held precedent
4 that a public utility’s actual capital structure should be used when it falls within the range of
5 the proxy group operating companies’ capital structures. Specifically, in its Opinion and
6 Order entered December 9, 2025, in Columbia Gas of Pennsylvania, Inc.’s (“Columbia”) 2025
7 Rate Case, the Commission adopted Columbia’s actual capital structure for the Fully
8 Projected Future Test Year (“FPFTY”) of 54.4% common equity, 43.28% long-term debt,
9 and 2.32% short-term debt and rejected OCA’s proposed hypothetical capital structure of 50%
10 common equity and 50% debt. *See Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket
11 Nos. R-2025-3053499, *et al.*, pp. 205-13 (Order entered Dec. 9, 2025). The Commission
12 reasoned that “the Company’s proposed capital structure . . . is within the five-year average
13 range of the capital structure ratios of the individual companies that comprise I&E’s Natural
14 Gas Utility proxy group.” *Id.* at 210.

15 Here, as noted by PPL Electric Witness Nelson, PPL Electric’s actual capital structure
16 of 56.05% equity and 43.95% long-term debt falls within both the five-year average range of
17 the capital structures for the operating companies in PPL Electric’s proxy group and I&E’s
18 proxy group. (See PPL Electric St. No. 10-R.) Therefore, although the Company maintains
19 that its proxy group should be used for the reasons outlined by Ms. Nelson in her rebuttal
20 testimony, PPL Electric’s actual capital structure should be used regardless of whichever
21 proxy group is adopted by the Commission.

1 Further, consistent with PPL Electric’s 2012 Rate Case, the Commission declared in
2 *Columbia*, “We find it appropriate to reinforce our finding, which we have outlined in several
3 recent base rate proceedings before this Commission, that ‘the use of an actual capital
4 structure represents the Company’s decision, in which it has full discretion, on how to
5 capitalize its rate base.’” *Columbia*, pp. 210-11 (quotation omitted). The Commission also
6 noted that it has repeatedly rejected OCA’s proposed “imposition of a hypothetical capital
7 structure” in PPL Electric’s 2012 Rate Case, Columbia’s 2021 Rate Case, PECO Energy
8 Company’s (“PECO”) 2021 Rate Case, Columbia Water’s 2024 Rate Case, and
9 Pennsylvania-American Water Company’s (“PAWC”) 2024 Rate Case. *Id.*, p. 212.

10 Despite this recent ruling, OCA and CAUSE-PA propose hypothetical capital
11 structures in this case that are more extreme than the 50% equity / 50% debt capital structure
12 proposed by OCA in *Columbia*, with OCA asking for a hypothetical capital structure of 42%
13 equity / 58% debt and CAUSE-PA suggesting a hypothetical capital structure of 44% equity
14 and 56% debt or, at the very least, a capital structure of 50% equity / 50% debt. From my
15 perspective, the Commission should once again reject these calls for a hypothetical capital
16 structure and, consistent with its longstanding precedent, adopt PPL Electric’s actual capital
17 structure.

18
19 **Q. The Commission recognized in *Columbia* that it could potentially exercise its discretion**
20 **to implement a hypothetical capital structure if it finds that the “utility’s actual capital**
21 **structure is atypical or too heavily weighted on either the debt or equity side.” *Columbia*,**

p. 212 (quotation omitted). Do you believe that PPL Electric's actual capital structure is atypical or too heavily weighted to the equity side?

A. No. As noted above, PPL Electric's actual capital structure falls within the range of capital structures for the proxy group operating companies. PPL Electric's actual capital structure supports the Company's strong credit ratings, financial stability, and ability to access lower-cost debt. The rating agencies prioritize financial strength and cash-flow, so a prudent equity-to-debt mix supports strong credit metrics and enhances overall credit quality, which lowers overall financing costs for customers and maintains access to capital through different market cycles. Furthermore, the Company's actual capital structure has been consistently maintained at a 56% equity ratio, as reflected in Schedule B-7, demonstrating a disciplined and consistent approach to managing its capital structure.

Q. Are there other flaws with the other parties' proposed hypothetical capital structures?

A. Yes. Like in *Columbia*, the other parties' hypothetical long-term debt ratios include more debt than the actual debt outstanding for PPL Electric, creating a mismatch between PPL Electric's actual debt and the assumed level of debt under the hypothetical capital structures that would be used for ratemaking purposes. Specifically, their proposed capital structures include the following amounts of additional debt than what is actually outstanding debt for PPL Electric in the FPFTY:

- I&E – Approximately \$160 million
- OCA – Approximately \$2.1 billion
- CAUSE-PA – Approximately \$1.8 billion (with a 44 percent equity ratio) or approximately \$1 billion (with a 50 percent equity ratio)

- EJA – Approximately \$1 billion

While the other parties suggest increasing leverage, they do not account for the cost implications of the additional long-term debt into their proposed hypothetical capital structures. Rather, the other parties either adopt PPL Electric's actual cost of debt (as I&E and OCA did) or take no position on cost of debt (as CAUSE-PA and EJA did). This approach ignores the critical fact that increasing leverage weakens credit metrics, increases financial risk, and would most likely result in a higher cost of debt and equity.

Q. Turning to more specific allegations by the other parties, do you agree with I&E Witness Breuning that a 50% equity and 50% long-term debt capital structure is the “optimal capital structure” (I&E St. No. 3. p. 19)?

A No. The optimal capital structure will depend on specific circumstances of the company and the prevailing market conditions; it is not a fixed formula. It depends on various factors, including the company's investment profile and risk tolerance. PPL Electric is capitalized to support the scale and nature of investments made and to maintain credit metrics that preserve a strong investment grade rating, which ultimately provides the Company the ability to access capital as needed during different market cycles and continue financing its investments at a reasonable cost for customers. The Company is making significant investments to modernize and harden its distribution system, which further supports the need for PPL Electric's proposed and actual capital structure.

1 **Q. Would you please respond to Mr. Breuning’s claim that PPL Electric’s capital structure**
2 **is “significantly more equity-heavy than the proxy group’s five-year averages and 2026**
3 **projections” (I&E St. No. 3, pp. 16-17)?**

4 A. I disagree with Mr. Breuning. PPL Electric’s proposed 56.05% equity and 43.95% debt
5 capital structure aligns with other peers in the industry and is within the range of equity ratios
6 of the proxy group of operating companies reflected in Ms. Nelson’s Capital Structure
7 analysis (see PPL Electric Exhibits JEN-8R and JEN-14R).

8
9 **Q. OCA Witness Garrett also disagrees with you regarding the Company’s credit ratings**
10 **and their relation to the authorized return on equity and capital structure on the**
11 **grounds that your position is allegedly “misleading.” (OCA St. 3, pp. 54-57.) Would**
12 **you please respond?**

13 A. I disagree with Mr. Garrett’s characterization of my position. My statement reflects the well-
14 established relationship between a utility’s capital structure, credit ratings, and its ability to
15 finance investments at reasonable costs. Rating agencies such as Moody’s and S&P evaluate
16 credit quality based on financial metrics like Funds from Operations (“FFO”)-to-debt, debt-
17 to-capital, and liquidity position, which are metrics that are directly influenced by the capital
18 structure. Their methodologies assign significant weight to financial strength (Moody’s:
19 ~40%) and leverage measures, meaning higher debt levels increase downgrade risk, which
20 then increase borrowing costs. Maintaining a prudent capital structure that supports strong
21 investment-grade ratings provides the Company with the ability to access capital at lower cost,
22 which benefits customers. Failing to recognize the connection between high credit quality

1 and borrowing costs underestimates the financial risks associated with higher leverage and
2 higher costs.

3
4 **Q. Do you agree with CAUSE-PA Witness Cicero that the Commission should view PPL**
5 **Electric's decision to allegedly skew its capital structure heavily to equity skeptically**
6 **(CAUSE-PA St. No. 1, pp. 15-16)?**

7 A. No, I do not agree. The Company's capital structure is not heavily weighted toward equity.
8 The equity ratio of 56.05% falls within the range of the proxy group of operating companies
9 provided by Ms. Nelson and, as previously mentioned, supports credit metrics to maintain
10 strong investment-grade credit ratings, which directly benefits customers by reducing the cost
11 of financing over time.

12
13 **Q. Do you believe it is appropriate to impute the capital structure of PPL Electric's ultimate**
14 **parent holding company, PPL Corporation, to PPL Electric, as proposed by Mr. Cicero**
15 **(CAUSE-PA St. No. 1, pp. 19-20)?**

16 A. No. As I explained previously, a hypothetical capital structure is not appropriate. The
17 Commission has consistently recognized that a utility's capital structure should reflect its
18 actual financing and risk profile. PPL Electric operates as a regulated utility with distinct
19 obligations, investments, and credit considerations that differ from the diversified operations
20 of PPL Corporation. Using the parent's structure would ignore these differences and could
21 result in an inappropriate cost of capital that does not accurately reflect the Company's
22 financial needs or regulatory requirements. Maintaining a capital structure based on PPL

1 Electric's actual operations ensures that PPL Electric's customers are not subsidizing costs
2 unrelated to their utility service.

3 Moreover, PPL Corporation is a diversified holding company with multiple
4 subsidiaries, including electric distribution operations in four states (Pennsylvania, Kentucky,
5 Rhode Island, and Virginia), transmission and generation operations, and natural gas
6 distribution operations. In other words, PPL Corporation benefits from operational,
7 geographic, and regulatory diversity, whereas PPL Electric's operational, geographic, and
8 regulatory risk is concentrated solely on its electric operations in Pennsylvania. Using PPL
9 Corporation's capital structure would incorrectly confer the benefits associated with PPL
10 Corporation's operational, geographic, and regulatory diversity that do not actually exist for
11 PPL Electric. More broadly, comparisons to the proxy group *holding company* capital
12 structures, as opposed to the proxy group *operating company* capital structures, are similarly
13 inappropriate due to differences in operational risks at the holding company level compared
14 to electric operating companies, as Ms. Nelson explains in her rebuttal testimony.

15 Lastly, Mr. Cicero is essentially advocating for a "double leverage" approach,
16 whereby the parent holding company's capital structure would be utilized instead of the
17 Company's actual capital structure. However, I am advised by counsel that the Commission
18 has rejected this approach in the past in favor of the utility's actual capital structure when, as
19 here, the utility's actual capital structure falls within the range of capital structures used by
20 "similar risk barometer group companies." *Pa. PUC v. ALLTEL Pa., Inc.*, 1985 Pa. PUC
21 LEXIS 53, at *107-08 (Order entered May 24, 1985); *Pa. PUC v. Phila. Suburban Water Co.*,

1 1991 Pa. PUC LEXIS 206, at *112 (Order entered Oct. 18, 1991) (quoting *Pa. PUC v.*
2 *Western Pa. Water Co.*, 63 Pa. P.U.C. 157, 197 (1987)).

3
4 **Q. EJA Witness Rábago asserts that the Company’s proposed capital structure is**
5 **“materially out of step with authorized returns and equity ratios across the U.S.” based**
6 **on “EEI’s Annual Financial Review for 2024.” (EJA St. No. 1, pp. 19-20.) He also points**
7 **to a report by RRA showing average equity ratios of 51.15% in 2023 and 49.26% in the**
8 **first half of 2024. (EJA St. No. 1, pp. 20-21.) Please respond.**

9 A. I do not agree that PPL Electric’s proposed capital structure is “materially out of step” with
10 peer utilities. While EEI and RRA reports provide broad averages, they do not account for
11 the specific circumstances of individual utilities, including investment requirements, credit
12 objectives, and regulatory environments. PPL Electric’s 56.05% equity ratio is well within
13 the range of peer utilities and is supported by the Company’s need to maintain strong
14 investment-grade credit ratings, financial flexibility and ability to access capital markets.

15
16 **Q. Mr. Rábago asserts that he is “not aware of empirical evidence that such risk” of over-**
17 **leveraging “really exists in financial markets today.” (EJA St. No. 1, p. 29.) Please**
18 **respond.**

19 A. I disagree with Mr. Rábago. The risk of higher leverage is well established and recognized
20 by credit rating agencies, regulators, and financial markets. Rating agency methodologies
21 treat weaker credit metrics, such as higher debt-to-capital and lower FFO-to-debt ratios, as
22 indicators of elevated risk, which can lead to downgrades and significantly higher financing

1 costs. These risks have been observed in recent market cycles where utilities with lower credit
2 metrics have faced rating pressure and increased cost of capital.

3
4 **Q. He also claims that “in the interim between rate cases, and outside of the historic test**
5 **year, the utility can obtain debt financing for its capital projects to create an unearned**
6 **windfall for the parent corporation and shareholders in New York” and then “[d]uring**
7 **the historic test year, the utility’s owners can issue equity, as PPL Corporation did, to**
8 **inflate its actual equity fraction, though historic analysis will show higher debt to equity**
9 **ratios.” (EJA St. No. 1, pp. 29-30.) Do you agree?**

10 **A.** No, I do not agree with Mr. Rábago’s claims, which mischaracterize both the regulatory
11 process and the Company’s financial practices. PPL Electric does not manipulate its capital
12 structure to create windfalls for its ultimate parent holding company. The Company’s
13 financing decisions are driven by legitimate business needs, such as funding significant
14 infrastructure investments and maintaining credit metrics that support strong investment-
15 grade ratings. These actions are consistent with sound financial management and regulatory
16 expectations, not opportunistic behavior. As demonstrated in Exhibit Fully Projected Future
17 1, Schedule B-7, PPL Electric has maintained an actual equity ratio of approximately 56% for
18 several years, including multiple periods between rate cases. This approach reflects a
19 consistent and disciplined capital structure strategy. Furthermore, to the extent that Mr.
20 Rábago is trying to make a “double leverage” argument, it should be rejected for the reasons
21 provided previously in response to Mr. Cicero.

1 **IV. CONCLUSION**

2 **Q. Please summarize your rebuttal testimony.**

3 A. PPL Electric's actual capital structure 56.05% equity / 43.95% debt is balanced, prudent, and
4 aligned with peer operating companies, supports strong credit metrics and financial flexibility,
5 and enables the Company to access capital at a lower cost, which directly benefits customers
6 by reducing long-term financing costs over time. Conversely, hypothetical structures
7 proposed by other parties increase leverage without accounting for the higher cost of debt and
8 equity and financial risk, which could ultimately increase the overall cost of capital for
9 customers. Furthermore, the Commission has strongly reaffirmed its long-held precedent that
10 a public utility's actual capital structure should be used if it falls within the range of the proxy
11 group of operating companies, which PPL Electric clearly does. As reflected in Exhibit Fully
12 Projected Future 1, Schedule B-7, PPL Electric has consistently applied a disciplined
13 approach to managing its capital structure. Thus, I recommend that the Commission reject
14 the hypothetical capital structures proposed by other parties and, consistent with its
15 longstanding precedent, adopt PPL Electric's actual capital structure.

16
17 **Q. Does this conclude your rebuttal testimony?**

18 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
JENNIFER NELSON
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Return on Equity
 Capital Structure**

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jennifer E. Nelson, and I am employed by Concentric Energy Advisors, Inc. (“Concentric”) as a Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. Did you previously file testimony in this proceeding?

A. Yes. I submitted my direct testimony, PPL Electric Statement No. 10 (“PPL Electric St. No. 10”), to the Pennsylvania Public Utility Commission (“PUC” or the “Commission”) on behalf PPL Electric Utilities Corporation (“PPL Electric”, or the “Company”), which is an indirect, wholly owned subsidiary of PPL Corporation, on September 30, 2025.

Q. Are you sponsoring any exhibits or schedules as part of your rebuttal testimony?

A. Yes. I sponsor the following exhibits:

- PPL Electric Exhibit JEN-1R – Constant Growth DCF Analysis
- PPL Electric Exhibit JEN-2R – Quarterly Growth DCF Analysis
- PPL Electric Exhibit JEN-3R – Market Return Estimate
- PPL Electric Exhibit JEN-4R – CAPM Analysis
- PPL Electric Exhibit JEN-5R – Risk Premium Analysis
- PPL Electric Exhibit JEN-6R – Capital Expenditure Analysis
- PPL Electric Exhibit JEN-7R – Regulatory Risk Analysis

- 1 • PPL Electric Exhibit JEN-8R – Capital Structure Analysis
- 2 • PPL Electric Exhibit JEN-9R – Constant Growth DCF Analysis Using Mr.
- 3 Breuning’s Proxy Group
- 4 • PPL Electric Exhibit JEN-10R – Quarterly Growth DCF Analysis Using Mr.
- 5 Breuning’s Proxy Group
- 6 • PPL Electric Exhibit JEN-11R – CAPM Analysis Using Mr. Breuning’s Proxy
- 7 Group
- 8 • PPL Electric Exhibit JEN-12R – Recommended Adjustments to Mr. Breuning’s
- 9 CAPM Analysis
- 10 • PPL Electric Exhibit JEN-13R – Illustrative Flotation Cost Analysis
- 11 • PPL Electric Exhibit JEN-14R – Capital Structure Analysis Using Mr. Breuning’s
- 12 Proxy Group
- 13 • PPL Electric Exhibit JEN-15R – CAUSE-PA Answer to PPL to CAUSE-PA-II-1
- 14 • PPL Electric Exhibit JEN-16R – EJA Answer to PPL to EJA-I-9
- 15 • PPL Electric Exhibit JEN-17R – I&E Answer to PPL to I&E-II-2
- 16

17 **Q. What is the purpose of your rebuttal testimony?**

18 A. In my rebuttal testimony, I respond to the direct testimonies of the following witnesses as
19 they relate to the appropriate return on equity (“ROE”) and capital structure for PPL
20 Electric:

- 1 • Mr. Drew Breuning on behalf of the Pennsylvania Public Utility Commission's
- 2 ("Commission") Bureau of Investigation and Enforcement ("I&E", "I&E St. No.
- 3 3");
- 4 • Mr. David J. Garrett on behalf of the Pennsylvania Office of Consumer Advocate
- 5 ("OCA", "OCA St. 3");
- 6 • Mr. Karl R. Rábago on behalf of the Energy Justice Advocates ("EJA", "EJA St.
- 7 No. 1");
- 8 • Mr. Patrick M. Cicero on behalf of the Coalition for Affordable Utility Services
- 9 and Energy Efficiency in Pennsylvania ("CAUSE-PA", "CAUSE-PA St. No. 1")
- 10 • Mr. Matthew T. Lyon on behalf of Walmart Inc. ("Walmart", "Walmart St. No. 1");
- 11 and
- 12 • Mr. Roger Colton on behalf of OCA ("OCA St. 8").

13 I collectively refer to these individual witnesses as the "Witnesses." My silence on
14 a particular issue should not be construed as agreement with respect to that issue.

15

16 **Q. How is the remainder of your rebuttal testimony organized?**

17 A. My rebuttal testimony is primarily organized by topic/issue raised by these Witnesses, as
18 follows:

19 Section II – provides an Executive Summary of my rebuttal testimony;

20 Section III – responds to the Witnesses regarding trends in the current capital market
21 environment;

1 Section IV – responds to the Witnesses’ references to national average authorized returns
2 for electric utilities as a benchmark for establishing the return for PPL Electric in this
3 proceeding, and the importance of placing those authorized returns in the proper context;

4 Section V – responds to certain witnesses with respect to the composition of a risk-
5 comparable proxy group for PPL Electric in this proceeding;

6 Section VI – addresses the proper application of the Discounted Cash Flow (“DCF”) model
7 and discusses areas of disagreement in the application of the DCF model;

8 Section VII – discusses areas of disagreement in the application of the Capital Asset Pricing
9 Model (“CAPM”), and in particular, the appropriate inputs to that model;

10 Section VIII – responds to the Witnesses’ comments and concerns with my application of
11 the Bond Yield Plus Risk Premium (“Risk Premium”) model;

12 Section IX – responds to the Witnesses’ positions regarding PPL Electric’s business risks;

13 Section X – presents the results of my updated ROE analyses based on market data through
14 December 31, 2025;

15 Section XI – presents the results of my capital structure analysis based on the updated
16 proxy group and responds to the Witnesses’ positions regarding PPL Electric’s proposed
17 capital structure; and

18 Section XII – summarizes my key conclusions and recommendations.
19

1 **II. EXECUTIVE SUMMARY**

2 **Q. What are your key conclusions regarding the analysis and recommendations**
3 **provided by the Witnesses regarding the appropriate ROE and capital structure for**
4 **PPL Electric?**

5 A. Although there are several areas in which I disagree with the Witnesses' methods and
6 conclusions, the key issues are:

7 1. Insufficiency of Mr. Garrett's and Mr. Rábago's ROE recommendations. Mr. Garrett's
8 and Mr. Rábago's ROE recommendations are unjustly low – below all authorized
9 ROEs for other electric utilities in at least the past 46 years.¹ No rational investor would
10 invest in PPL Electric if they could earn a higher return investing in any other electric
11 utility. Mr. Garrett's and Mr. Rábago's ROE recommendations defy any rational basis
12 and should be dismissed from the outset.

13 2. Flawed application of their ROE analytical models. The Witnesses' analyses contain
14 flaws and inconsistencies, with some that produce results below any reasonable
15 measure of PPL Electric's cost of equity. I address each analytical approach and
16 recommend corrections where appropriate.

17 3. Misunderstanding of the current capital market environment and disregard for the
18 higher long-term capital cost environment since PPL Electric's last rate cases. The

¹ Source: S&P Capital IQ Regulatory Research Associates ("RRA"). Excludes ROEs authorized for The United Illuminating Co. in case no. 22-08-08 and Central Maine Power Co. in case no. 2018-00194 because they included ROE penalties. Also excludes ROEs authorized for Green Mountain Power Corp., Ameren Illinois, and Commonwealth Edison Co., as these ROEs were set by changes in Treasury bond yields. The framework for setting these ROEs is not comparable to the framework used in setting the ROE that will be authorized for PPL Electric.

1 Witnesses generally do not acknowledge the higher long-term interest rates and
2 inflation since the Company's 2012 and 2015 rate cases. Instead, they give undue
3 weight to inputs and models that bias their ROE estimates and recommendations
4 downward and result in recommendations to *reduce* PPL Electric's authorized ROE,
5 contrary to prevailing capital market trends. As I explain below, government and utility
6 bond yields increased by approximately 190 basis points on average since the
7 Commission's last ROE determination for PPL Electric in 2012 and since PPL
8 Electric's black-box settlement in 2015.² It is important that the return authorized in
9 this proceeding keeps pace directionally with the increase in capital costs so that PPL
10 Electric can compete for capital among its peers that also have significant capital
11 needs.³ Doing so ensures that the Company continues to provide safe and reliable
12 service to customers at a reasonable cost.

- 13 4. *Incorrect comparison of PPL Electric's capital structure to the proxy group holding*
14 *companies rather than the proxy group operating companies.* The correct comparison
15 when analyzing a subject company's capital structure is to the proxy group *operating*
16 *companies*, not the proxy group *holding companies*. The Witnesses' flawed
17 comparisons lead to equity ratio recommendations that are significantly below PPL
18 Electric's projected actual equity ratio. When the comparison is performed correctly
19 to the proxy group operating company capital structures, PPL Electric's requested

² Note that there was no ROE determination in PPL Electric's black-box settlement in 2015.

³ See, e.g., PPL Electric Exhibit JEN-6R.

56.05 percent equity ratio is within the range of the proxy group companies, consistent with sound industry practice, and is consequently reasonable and appropriate.

Q. Please provide an overview of the Witnesses' ROE analytical results and overall ROE recommendations in this proceeding.

A. As shown in Figure 1, the Witnesses⁴ base their recommendations on analyses that range from a low of 7.3 percent to a high of 10.32 percent.

Figure 1: ROE Ranges and Recommendations of the Witnesses

	I&E Witness Breuning	OCA Witness Garrett	EJA Witness Rábago	CAUSE-PA Witness Cicero	Walmart Witness Lyon
DCF Results (Range)	10.32%	(7.3% - 8.7%)	N/A	N/A	N/A
CAPM Results (Range)	9.04% (8.36%-9.71%)	(7.6% - 8.4%) ⁵	N/A	N/A	N/A
ROE Recommendation	10.32%	8.4%	7.67%	Sufficient but not Excessive	Reject 11.30%
Equity Ratio Recommendation	55%	42%	50%	50%⁶	N/A

⁴ Mr. Colton does not present ROE or equity ratio recommendations.

⁵ Mr. Garrett recommends a CAPM cost of equity of 8.4 percent only if his recommended 42 percent equity ratio is used. If the Company's recommended equity ratio of 56 percent is used, Mr. Garrett recommends a 7.6 percent ROE. (OCA St. 3, p. 56.)

⁶ Mr. Cicero recommends that "the Commission impute either the capital structure of PPL's grandparent – PPL Corporation – or, at the very least, a more reasonable 50/50 structure." As he presents a 50/50 capital structure and does not present the capital structure of PPL Corporation, I specifically address his 50/50 capital structure in my rebuttal testimony, though my conclusions and recommendations would also apply to his recommendation of the capital structure of PPL Corporation.

1 There are several flaws and inconsistencies with the analyses conducted by these
2 Witnesses. I address each analytical approach and recommend corrections where
3 appropriate. At the outset, one must question analyses producing results that are below all
4 authorized ROEs for other electric utilities in at least the past 46 years that do not include
5 an ROE penalty nor are the result of formulaic ROEs tied to annual changes in Treasury
6 yields. Further, I submit that the only reliable method for determining the cost of capital
7 is through the application of rigorous analysis using financial models and market data from
8 reliable sources, coupled with a comprehensive risk assessment of the regulated utility. As
9 such, the Commission should reject the ROE recommendations of OCA Witness Garrett,
10 EJA Witness Rábago, CAUSE-PA Witness Cicero, and Walmart Witness Lyon from the
11 outset. As for I&E Witness Breuning, I recommend that the Commission reject his CAPM
12 model results as filed. While his DCF methodology and result are in line with my Constant
13 Growth DCF methodology and results, by relying solely on one model, the DCF model,
14 Mr. Breuning's recommendation fails to consider other market-based models that more
15 directly incorporate changes in the prevailing capital market conditions. For example, the
16 CAPM and Risk Premium approaches rely on bond yields as direct inputs; thus, these
17 models more directly incorporate the fact that bond yields have increased by approximately
18 190 basis points since PPL Electric's 2012 and 2015 rate cases, as I explain below. The
19 DCF model, on the other hand, only indirectly reflects changes in interest rates and bond
20 yields implicitly through changes in stock prices and growth rate expectations. The use of
21 multiple methodologies, therefore, enables a more robust and comprehensive estimate of
22 the cost of equity.

1
2 **Q. Please summarize the cost of capital recommendations presented by the various**
3 **witnesses in this proceeding.**

4 A. I&E Witness Breuning performs a DCF analysis that is largely similar to mine to arrive at
5 his 10.32 percent ROE recommendation. He also conducts two CAPM analyses, which
6 average a 9.04 percent ROE estimate, yet contain multiple flaws in his selected model
7 inputs. Mr. Breuning ultimately recommends that the Commission not rely on the results
8 of his CAPM analyses.⁷ OCA Witness Garrett performs two DCF analyses and a CAPM
9 analysis, each of which produces a result at or below 8.7 percent (i.e., below all authorized
10 ROEs for other electric utilities in at least the past 46 years) and contain flaws. EJA
11 Witness Rábago uses a calculation based on a spurious assumption related to PPL
12 Corporation's market-to-book ratio to arrive at his 7.67 percent ROE recommendation.⁸
13 CAUSE-PA Witness Cicero and Walmart Witness Lyon do not give a specific ROE
14 recommendation, though recommend that the approved ROE not be excessive.

15 Regarding PPL Electric's capital structure, Mr. Breuning and Mr. Garrett
16 incorrectly reference the proxy group *holding company* capital structures, as opposed to
17 the proxy group *operating company* capital structures, to arrive at their respective 55
18 percent and 42 percent equity ratio recommendations. Meanwhile, Mr. Rábago and Mr.
19 Cicero largely use qualitative methods to arrive at their 50 percent equity ratio
20 recommendations.

⁷ I&E St. No. 3, pp. 23-29, 39-40.

⁸ EJA St. No. 1, pp. 25-27.

1
2 **Q. What are the practical implications for a utility that has an authorized return that is**
3 **far below ROEs authorized for other electric utilities?**

4 A. The significant difference between OCA Witness Garrett's and EJA Witness Rábago's
5 ROE recommendations and those available to other electric utilities raises a very practical
6 concern. The Company must compete with other companies, including other utilities, for
7 the long-term capital needed to provide utility service. No rational investor would invest
8 in a utility whose authorized ROE falls far below industry levels. Further, if Mr. Garrett's
9 or Mr. Rábago's recommendations were adopted, it would introduce significant uncertainty
10 in the stability and consistency of the regulatory environment in Pennsylvania. The market
11 would likely react swiftly and harshly to authorized ROEs and equity ratios that were
12 hundreds of basis points lower than those authorized by the Commission. Such a
13 significant departure from the Commission's practice would not only adversely affect the
14 Company's financial profile but could have severe ramifications for all Pennsylvania
15 utilities.

16
17 **Q. How has the cost of capital changed since PPL Electric's 2012 and 2015 rate cases?**

18 A. The cost of capital has increased. As can be seen in Figure 2 below, government and utility
19 bond yields are, on average, approximately 190 basis points above where they were when
20 the Company's ROE was set by the Commission at 10.4 percent in 2012 and since PPL
21 Electric's most recent black-box settled rate case in 2015.

Figure 2: Treasury Bond and Utility Bond Yields (2012 and 2015 vs. 2025)⁹

	10-yr Treasury Bond	30-yr Treasury Bond	Moody's A Utility Bond
12/5/12 (PPL Electric 2012 Rate Case)	1.68%	2.83%	3.85%
11/19/15 (PPL Electric 2015 Rate Case)	2.16%	2.96%	4.35%
6/30/25 (Nelson Direct)	4.41%	4.92%	5.98%
12/31/25 (Nelson Rebuttal)	4.12%	4.77%	5.66%
12/31/25 vs. 12/5/12 Change (bps)	244	194	181
12/31/25 vs. 11/19/15 Change (bps)	196	181	131

The Witnesses recommend ROEs that are lower than the 10.4 percent ROE that the Commission authorized for PPL Electric in 2012, even though none of the Witnesses demonstrate that PPL Electric's risk is so much lower now than in 2012 or 2015, especially as the cost of capital has increased significantly since then.

Q. Messrs. Breuning, Rábago, Cicero, Lyon, and Colton oppose your recommended ROE due to affordability concerns, particularly for low to moderate income customers. What is your response?

A. First, I understand that the Company offers programs to assist customers who experience hardships. Affordability concerns for low-income customers are not limited to PPL Electric, and utilities across the country have implemented programs to assist customers experiencing hardships. Nevertheless, the Company must balance customer affordability with its need for ongoing system investment to meet its obligation to provide customers

⁹ Source: S&P Capital IQ, 30-trading day averages.

1 with safe and reliable service. Customers benefit from a just and reasonable ROE that
2 reflects the market-based cost of equity, as I explain in more detail in Section III.
3 Additionally, the guidelines established in *Hope* and *Bluefield*, which have been relied
4 upon for more than 80 years to set the cost of capital for a regulated utility,¹⁰ do not
5 explicitly include affordability as part of the standards for determining the just and
6 reasonable return. In my opinion, affordability issues are better addressed with the
7 universal service programs discussed in the direct testimony of PPL Electric Witness
8 Norden (PPL Electric St. No. 18), rather than through an excessively low ROE that could
9 have significant adverse impacts on the Company's ability to access capital on effective
10 terms for the benefit of customers. I also note that PPL Electric Witness Wishart further
11 responds to the affordability concerns raised by other parties in more detail (see PPL
12 Electric St. No. 8-R).

13
14 **Q. Mr. Breuning, Mr. Rábago, and Mr. Lyon reference authorized ROEs for electric**
15 **utilities in other jurisdictions or articles that suggest that authorized ROEs exceed the**
16 **cost of equity. Should this information be given any weight in this proceeding?**

17 **A.** No, it should not. As I explain further in Section IV, national average returns must be
18 placed in the proper context to be useful. Further, the referenced articles contain numerous
19 weaknesses and faulty assumptions, which only serve to distract from the fact-based
20 evidence in this proceeding. This case is unique, and simple comparisons to other

¹⁰ See PPL Electric St. No. 10, pp. 8-13.

1 jurisdictions or outside opinions cannot substitute for a fact-based analysis of the current
2 market information and business risks unique to PPL Electric in this docket.

3
4 **Q. Mr. Breuning, Mr. Cicero, and Mr. Lyon contend that PPL Electric’s regulatory**
5 **mechanisms reduce its risk. Do you agree?**

6 A. As compared to the proxy group, I do not. While regulatory mechanisms such as the
7 Distribution System Improvement Charge (“DSIC”), fully projected future test year
8 (“FPFTY”), and Storm Damage Expense Rider (“SDER”) may reduce risk on an absolute
9 basis, the majority of the proxy group operating companies utilize similar mechanisms, as
10 I explain and quantify in Section IX. As such, PPL Electric’s level of regulatory risk is
11 similar to that of the proxy group. Further, the market data used in my various models
12 reflect these regulatory constructs in other jurisdictions and therefore investors’
13 perceptions regarding the effect of these constructs on the proxy companies’ risk profiles.
14 CAUSE PA Witness Cicero, on the other hand, acknowledges that he has not evaluated
15 whether other utility companies have similar alternative ratemaking mechanisms in the
16 context of this case, though he agrees that “to the extent that any other utility utilizes the
17 Fully Projected Future Test Year, the Distribution System Improvement Charge, or any
18 other alternative ratemaking methodology provided in 66 Pa. C.S. § 1330, then they would
19 be availing themselves of the ways in which Pennsylvania has modified traditional cost of
20 service ratemaking.”¹¹ PPL Electric’s authorized ROE should not be lowered due to its
21 regulatory mechanisms.

¹¹ PPL Electric Exhibit JEN-15R [CAUSE-PA Answer to PPL to CAUSE-PA-II-1].

1
2 **Q. What are your conclusions?**

3 A. As discussed in my direct and rebuttal testimonies, it is critical that PPL Electric maintain
4 its financial profile in order to provide safe, reliable service to the benefit of customers.
5 Whereas I&E Witness Breuning's recommended ROE overlaps with my range, the
6 remaining Witnesses' recommendations to substantially reduce PPL Electric's authorized
7 ROE run counter to the higher capital cost environment the Company faces and would
8 impede PPL Electric's ability to compete for the external capital it needs to fund necessary
9 investments. As discussed above, these Witnesses' ROE recommendations are below all
10 authorized ROEs for other electric utilities in at least the past 46 years, apply flawed ROE
11 analytical models, or disregard current capital market conditions adversely affecting PPL
12 Electric's ability to recover its capital costs. While the results of my collective updated
13 DCF, CAPM, ECAPM, and Risk Premium analyses have increased since the initial filing,
14 I conservatively maintain my range from 10.30 percent to 12.35 percent, which continues
15 to support my 11.30 percent ROE recommendation. Based on the analyses discussed
16 throughout my rebuttal testimony, my 11.30 percent ROE recommendation remains a just
17 and reasonable estimate of PPL Electric's cost of equity that appropriately reflects the
18 increased cost of capital since PPL Electric's last rate cases.

19 Additionally, Mr. Breuning and Mr. Garrett present flawed arguments to compare
20 PPL Electric's proposed capital structure to the proxy group *holding company* capital
21 structure instead of the proxy group *operating company* capital structure, while Mr. Rábago
22 and Mr. Cicero argue without merit that the Commission should enact a 50 percent equity

1 and 50 percent long-term debt capital structure. As I explain in Section XI, the
2 Commission should reject these arguments and approve PPL Electric's requested 56.05
3 percent equity ratio, as it is within the range of the proxy group operating companies.
4

5 **III. CURRENT CAPITAL MARKET ENVIRONMENT**

6 **Q. Messrs. Breuning, Rábago, Cicero, Lyon, and Colton raise concerns related to the**
7 **rate impact of PPL Electric's requested ROE and equity ratio.¹² How do you**
8 **respond?**

9 A. The issue of affordability is a consequence of growing challenges utilities face to provide
10 safe and reliable service, the costs of which need to be recovered from customers. These
11 challenges are primarily due to significant capital investment, which "broke a new record
12 in 2025 for the fourth consecutive year, reflecting about \$250 billion."¹³ For example, in
13 its credit outlook for 2026, S&P notes that one of its key assumptions for the following
14 year includes cash flow deficits of about \$100 billion, which would require utilities to
15 access capital markets.¹⁴ Furthermore, S&P notes that companies have minimal financial
16 cushion, as "[a]bout 40% of the industry is operating with limited ability to absorb
17 unexpected events beyond their base case."¹⁵ One of S&P's key assumptions for 2026 is

¹² I&E St. No. 3, p. 56; EJA St. No. 1, pp. 20, 29; CAUSE-PA St. No. 1, pp. 17, 20-22; Walmart St. No. 1, pp. 9, 14; OCA St. 8, pp. 27-28.

¹³ S&P Global Ratings, "Industry Credit Outlook 2026 North America Regulated Utilities" January 14, 2026, at 1.

¹⁴ *Id.*

¹⁵ *Id.*

1 that the utility industry will require “consistently fair rate case orders to maintain credit
2 quality.”¹⁶

3 Further, customers benefit from a just and reasonable ROE that reflects the market-
4 based cost of equity (i.e., as I have done with my DCF, CAPM, and Risk Premium
5 analyses). This is explained by the National Association of Regulatory Utility
6 Commissioners (“NARUC”):

7 Customers benefit by having a financially stable utility that has the
8 earnings and cash flow sufficient to attract equity and debt on
9 reasonable terms, and the resulting ability to provide safe, reliable,
10 and affordable utility service. Receiving a reasonable authorized
11 ROE and capital structure from regulators is an important
12 contributor to financial stability. The customer benefits that result
13 from being served by a financially healthy utility outweigh the
14 illusory short-term “benefits” of a negative regulatory climate that
15 heightens regulatory risk.

16 The level of authorized ROE and the ability to earn the authorized
17 ROE through an appropriate capital structure used for ratemaking
18 and tariff-setting are important considerations for investors’
19 evaluation of regulatory quality and risk. Regulatory lag may lead
20 to an earned ROE that falls short of the authorized ROE, thus
21 negatively impacting investors’ evaluation of regulatory quality and
22 risk..

23 ***

24 Regulators are more effective at serving customers when they
25 harness investors’ desire to provide capital rather than constrain it.¹⁷

¹⁶ *Id.*

¹⁷ National Association of Regulatory Utility Commissioners, “A Cost of Capital and Capital Markets Primer for Utility Regulators,” April 2020, at 8.

1 **Q. Mr. Breuning discusses recent and prospective monetary policy actions by the**
2 **Federal Reserve.¹⁸ Does the Federal Reserve’s cuts to the Federal Funds rate mean**
3 **that long-term government and utility bond yields will automatically follow?**

4 A. Not necessarily. As a preliminary matter, Mr. Breuning’s contention that “the Federal
5 Reserve’s intention to cut interest rates in 2025-2026, which would have the effect of
6 *reducing* potential inflation”¹⁹ is incorrect. As a general principle, the Federal Reserve
7 reduces the Federal Funds rate to stimulate the economy and job growth (i.e., money is
8 cheaper to borrow, so people and businesses spend and invest more), which can increase
9 inflation, whereas it increases rates as a means to tame inflation (i.e., people and businesses
10 are more likely to save and not borrow money when interest rates are higher). This is why
11 the Federal Reserve’s dual mandate to maintain price stability while maximizing
12 employment is challenging – the two objectives are at odds with each other. As such, if
13 the Federal Reserve were to further cut rates in 2026, it is possible that inflation could
14 continue to increase. I note, however, that price control is not easily achieved through
15 monetary policy alone and that high inflation can occur even if economic growth is weak
16 and unemployment is rising (this phenomenon is commonly referred to as “stagflation”).

17 Notwithstanding, long-term bond yields – like the 30-year Treasury yield that is
18 applied in the ROE models and used as a benchmark for long-term debt – are less sensitive
19 to the Federal Reserve’s monetary policy. As I explained in my direct testimony,²⁰ and
20 updated below in Figure 3, while short-term 1-year and 2-year Treasury yields have

¹⁸ I&E St. No. 3, pp. 28, 53;

¹⁹ I&E St. No. 3, p. 28 (emphasis added).

²⁰ PPL Electric St. No. 10, p. 57.

declined by 161 and 124 basis points, respectively, since the Federal Reserve started cutting interest rates in 2024, 10-year Treasury yields have only slightly decreased and long-term 30-year Treasury yields have actually *increased* by 33 basis points. Since models used to estimate the just and reasonable ROE rely primarily on long-term yields, the market movement of short-term yields does not influence the ROE model results as the longer-term yields do. As such, even though the Federal Reserve has cut the Federal Funds Rate by 25 basis points in each of September, October, and December 2025 (75 basis points total),²¹ this could have minimal impacts on the cost of equity for a regulated utility such as PPL Electric.

Figure 3: U.S. Treasury Yields (June 2024 vs. December 2025)²²

	1-year Treasury	2-year Treasury	10-year Treasury	30-year Treasury
June 28, 2024	5.09%	4.71%	4.36%	4.51%
December 31, 2025	3.48%	3.47%	4.18%	4.84%
Change	-1.61%	-1.24%	-0.18%	0.33%

²¹ <https://www.federalreserve.gov/newsevents/pressreleases/monetary20251210a.htm>.

²² Source: Spot yields reported by Federal Reserve Board of Governors, H15 Selected Interest Rates. <https://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15>.

1 **Q. Are the key factors affecting the cost of equity for regulated utilities in the current**
2 **and prospective capital markets that you described in your direct testimony²³ still**
3 **present at this time?**

4 **A.** Yes, they are. Long-term interest rates remain and are expected to stay elevated, inflation
5 levels and expectations remain above the Federal Reserve’s two percent target, and
6 geopolitical uncertainty is still higher than it is normally.

7 U.S. consumers continue to expect inflation to remain elevated. As the University
8 of Michigan’s Surveys of Consumers Director Joanne Hsu explains in the December 2025
9 consumer sentiment report on inflation:

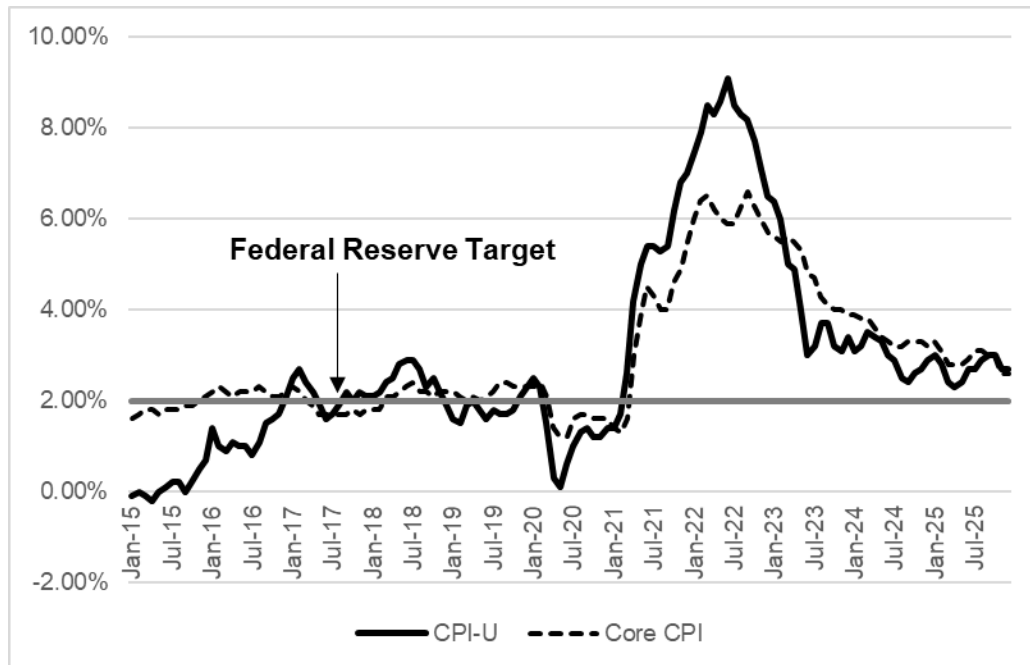
10 Year-ahead inflation expectations decreased for the fourth
11 consecutive month to 4.2%. This is the lowest reading in 11 months
12 but is still above the 3.3% seen in January. Long-run inflation
13 expectations eased from 3.4% last month to 3.2% in December,
14 matching the January 2025 reading.²⁴

15 Further, as shown in Figure 4 below, the pace of inflation (both the overall inflation
16 rate and core inflation rate) remains elevated above the Federal Reserve’s 2.0 percent
17 target.

²³ PPL Electric St. No. 10, p. 52.

²⁴ University of Michigan, Survey of Consumers, “Final Results for December 2025”, accessed December 24, 2025, <https://www.sca.isr.umich.edu/>.

Figure 4: Year-Over-Year Inflation (2015-2025)²⁵



Additionally, the policy uncertainty that has resulted from the federal administration's shifting trade policies remains. As can be seen in Figure 5 below, the Federal Reserve Bank of St. Louis's Economic Policy Uncertainty Index remains elevated (349.59 as of December 2025 vs. an average level of 152.52). This indicates that there is still significant uncertainty related to international trade and the economy. The January 3, 2026 U.S. bombing of Venezuela and subsequent capture of Venezuelan President Maduro²⁶ and a potential criminal investigation into Federal Reserve Chair Powell²⁷ add

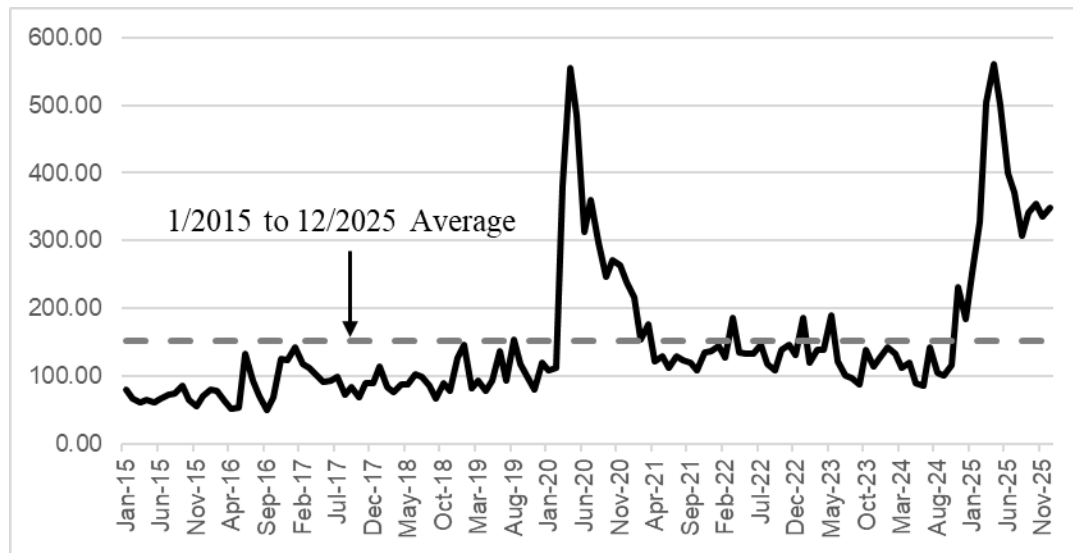
²⁵ Source: U.S. Bureau of Labor Statistics.

²⁶ <https://www.cbsnews.com/live-updates/venezuela-us-military-strikes-maduro-trump/>.

²⁷ <https://abcnews.go.com/Politics/doj-launches-criminal-investigation-fed-chair-jerome-powell/story?id=129114228>.

further to the economic and geopolitical uncertainty. Uncertainty increases risk, which increases the cost of equity, all else equal.

Figure 5: Economic Policy Uncertainty Index January 2015 – December 2025²⁸



IV. COMPARABLE RETURNS FOR ELECTRIC UTILITIES

Q. Mr. Breuning, Mr. Rábago, and Mr. Lyon reference authorized ROEs for electric utilities in other jurisdictions.²⁹ Do you agree that these returns are relevant for establishing the authorized ROE for PPL Electric in this proceeding?

A. National average returns must be placed in the proper context in order to be useful. While I agree that investors consider authorized returns in other states in assessing the

²⁸ Federal Reserve Bank of St. Louis Economic Database (FRED), Economic Policy Uncertainty Index for United States (USEPUINDXD), <https://fred.stlouisfed.org/series/USEPUINDXD>.

²⁹ I&E St. No. 3, p. 56; EJA St. No. 1, pp. 19-21; Walmart St. No. 1, pp. 10-12.

1 reasonableness of the authorized ROE for PPL Electric, I have several concerns with the
2 nationwide average allowed ROE information presented by certain witnesses.

3 First, Mr. Breuning mischaracterizes my discovery response when he states, “Ms.
4 Nelson indicated she was unaware if any electric utilities throughout the United States were
5 granted a Commission authorized return of 11.30% or higher cost of common equity in the
6 past two years.”³⁰ To clarify, my response was, “While [I am] not aware of an electric
7 *distribution-only* utility receiving an authorized ROE of 11.30% or higher in the last two
8 years, [I am] aware that vertically integrated electric utility Alaska Electric Light and
9 Power (Alaska jurisdiction) was granted an 11.45 percent return on equity (with a 60.70%
10 common equity ratio) in 2023.”³¹ Additionally, Mr. Rábago claims that “EEI’s graphs of
11 requested and allowed ROE show that regulators have not allowed an ROE above 10%
12 since 2016.”³² This is a clear misstatement of fact and misinterpretation of the graph, which
13 shows the average allowed ROE, not the maximum allowed ROE. In fact, based on data
14 from RRA, there were 63 electric utility ROEs approved from January 1, 2016, through
15 December 31, 2025, that were at or above 10 percent.³³ Moreover, Mr. Breuning
16 recommends an ROE above 10 percent (10.32 percent).

17 Second, market conditions at the time the authorized returns were established may
18 be very different than conditions expected going forward. For example, the 2023 and early
19 2024 authorized ROE data that Mr. Rábago and Mr. Lyon cite³⁴ are not a reasonable basis

³⁰ I&E St. No. 3, p. 56.

³¹ I&E Exhibit No. 3, Schedule 25 (clarification added).

³² EJA St. No. 1, p. 20.

³³ Source: RRA. Excludes “Limited-Issue Rider” and “Transmission” cases.

³⁴ EJA St. No. 1, pp. 20-21; Walmart St. No. 1, p. 11.

1 of comparison for evaluating the authorized ROE in this proceeding. Those cases likely
2 were filed in 2022 or 2023, when bond yields were significantly below where they are as
3 of December 31, 2025.³⁵

4 Finally, this case is unique, and simply referencing recently authorized ROEs of
5 other jurisdictions would not take into account the unique business risks of PPL Electric
6 that I explain throughout my direct and rebuttal testimonies. Further, mechanical
7 comparisons to decisions in other jurisdictions obscure the nuances present in each
8 individual case. For example, the 8.63 percent low ROE that Mr. Lyon cites³⁶ is actually
9 a base ROE of 9.10 percent that was lowered with a 47-basis point penalty that The United
10 Illuminating Co. received “to address performance and management issues.”³⁷ In
11 summary, comparisons to past cases in other jurisdictions cannot substitute for a fact-based
12 analysis of the current market information related to PPL Electric in this docket.

13
14 **Q. Mr. Rábago references articles that suggest that authorized ROEs exceed the cost of**
15 **equity.³⁸ Do you agree with the conclusions of the authors of those articles?**

16 **A.** No, I do not. The referenced articles contain serious flaws in the logic that would not
17 withstand the scrutiny of a regulatory commission proceeding. For example, the article
18 from the Rocky Mountain Institute (“RMI”) incorrectly asserts that the geometric average

³⁵ See PPL Electric St. No. 10, Figure 13; Figure 2 above.

³⁶ Walmart St. No. 1, p. 10.

³⁷ *Application of the United Illuminating Company to Amend its Rate Schedule*, Docket No. 22-08-08, Decision, August 25, 2023 at 1.

³⁸ EJA St. No. 1, pp. 23-25.

1 market return should be used in the CAPM.³⁹ However, geometric returns are backward
2 looking and thus are not the proper measurement for estimating the forward-looking cost
3 of equity.⁴⁰ The RMI Article also incorrectly claims that “[i]f a utility’s ROE is
4 numerically the same as its [cost of equity], its stock should trade at book value.”⁴¹ I
5 address this fallacy below. Lastly, the RMI Article attempts to illustrate mathematically
6 that an increase in the cost of debt as a result of a credit rating downgrade from a below
7 market authorized ROE is offset by the lower authorized ROE,⁴² similar to an argument
8 that Mr. Garrett makes.⁴³ The flaw in the authors’ (and Mr. Garrett’s) argument is that it
9 erroneously presumes that a credit rating downgrade only affects the cost of debt and not
10 the cost of equity. An authorized return below what the market expects, as presumed by a
11 credit rating downgrade, indicates higher regulatory risk and greater uncertainty in returns
12 to the equity investor. Equity investors will require a higher return to compensate them for
13 greater risk. Thus, the required cost of equity *increases* in response to a credit rating
14 downgrade.

15 Additionally, the American Economic Liberties Project article published by Mark
16 Ellis⁴⁴ has numerous flaws and misrepresentations related to areas such as inflation and

³⁹ Rocky Mountain Institute, *Rebalancing “Return on Equity” to Accelerate an Affordable Clean Energy Future* (February 21, 2025), <https://rmi.org/rebalancing-return-on-equity-to-accelerate-an-affordable-clean-energy-future/> (“RMI Article”).

⁴⁰ No Witness has used geometric returns in this proceeding or claimed that they are the proper measurement for estimating the cost of equity. In the interest of brevity, I will not cover this topic in further detail.

⁴¹ RMI Article (clarification added).

⁴² *Id.*

⁴³ OCA St. 3, p. 58.

⁴⁴ Mark Ellis, American Economic Liberties Project, *Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities from Overcharging the Public*, 11 (Jan. 2025), <https://www.economicliberties.us/wp-content/uploads/2025/01/20250102-aelp-ror-v5.pdf> (“Ellis Article”).

1 utility rates, the market-to-book ratio concept that I address below, utility investment, and
2 market return forecasts. I have previously addressed Mr. Ellis and his ROE
3 recommendations that are typically in the 5 to 7 percent range⁴⁵ and those arguments (i.e.,
4 not meeting the *Hope* and *Bluefield* standards and flawed inputs and analyses) apply to this
5 article as well. As such, the Commission should not give any weight to the RMI Article or
6 the Ellis Article.

7
8 **Q. Mr. Rábago argues that PPL Electric's cost of equity is 7.67 percent, based on a**
9 **calculation that uses PPL Corporation's price-to-book ratio (also known as "market-**
10 **to-book ratio" or "M/B ratio") to discount its last approved ROE.⁴⁶ Do you agree**
11 **with this approach and conclusion?**

12 A. No. By using this calculation (which Mr. Rábago incorrectly refers to as a "discounted
13 cash flow calculation"⁴⁷), Mr. Rábago is making a flawed conclusion that an M/B ratio
14 above 1.0 means that a company's ROE is above its cost of equity. Utility M/B ratios in
15 excess of 1.0 are not evidence that regulators are setting authorized ROEs above the cost
16 of equity; there are several flaws with this oversimplified argument. The use of M/B ratios
17 to evaluate the cost of equity is an outdated view that does not consider that most publicly
18 traded companies trade above book value (see Figure 6 below) and that utilities compete
19 for capital among all companies, both regulated and nonregulated. Publicly traded utility

⁴⁵ See Rebuttal Testimony of Jennifer E. Nelson on Behalf of Virginia Electric and Power Company, Case No. PUR-2025-00058, September 10, 2025, <https://www.scc.virginia.gov/docketsearch/DOCS/88%25z01!.PDF>.

⁴⁶ EJA St. No. 1, pp. 25-26.

⁴⁷ EJA St. No. 1, p. 25.

holding companies (e.g., PPL Corporation) are the entities with a publicly available market value. The regulated utility operating companies to which the authorized ROEs apply (e.g., PPL Electric) are not publicly traded, and thus their market value is not observable. Publicly traded holding companies are diversified companies, many of which operate both regulated and unregulated business segments across multiple jurisdictions. Therefore, the stock prices of the publicly traded holding companies reflect investors' return requirements for the consolidated entity on a sum-of-the-parts basis.

Figure 6: Price-to-Book Ratio by Sector⁴⁸

Sector	12/31/25	12/31/24	12/31/23	12/31/22
Communications	5.93	5.10	3.91	2.61
Consumer Discretionary	9.22	10.06	9.40	7.54
Consumer Staples	6.55	6.33	5.54	6.12
Energy	1.93	1.99	2.13	2.50
Financials	2.48	2.33	2.05	1.64
Health Care	5.21	4.86	4.83	5.07
Industrials	6.72	6.35	5.82	5.27
Information Technology	13.40	13.09	11.42	7.93
Materials	2.90	2.74	3.01	2.90
Real Estate	3.03	3.02	3.03	3.00
Utilities	2.35	2.22	1.93	2.21

As Figure 6 shows, publicly traded company market values in all sectors, both regulated and unregulated, exceed book value. As Dr. Roger Morin notes, "M/B ratios are determined by the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials are commanding M/B ratios well in excess of

⁴⁸ Sibilis Research, "Price-to-Book (P/B) Ratio by Sector (U.S. Large Cap)", 2025, <https://sibilisresearch.com/data/price-to-book-sector/>.

1 1.0 while regulation reduces their M/B toward 1.0.”⁴⁹ To enable utilities the ability to
2 attract capital that is not significantly dilutive, the market price must be sufficiently above
3 book value.

4 Finally, when asked if he was aware of any state utility commission that has used
5 this methodology, Mr. Rábago responded that he “is not aware whether any regulatory
6 authorities have used the methodology described in his testimony.”⁵⁰ As such, I strongly
7 recommend that the Commission reject Mr. Rábago’s flawed argument and ROE estimate.
8

9 **V. PROXY GROUP COMPOSITION**

10 **Q. Have you made any changes to your proxy group as compared to the proxy group**
11 **you used in your direct testimony?**

12 A. Yes. I removed NorthWestern Energy Group, Inc. (“NWE”), as NWE recently announced
13 a merger with Black Hills Corp.⁵¹ My proxy group is otherwise unchanged from what I
14 used in my direct testimony.⁵²
15

16 **Q. Please summarize the proxy groups of the other Witnesses.**

17 A. I&E Witness Breuning develops a proxy group of 16 electric utilities based on his six
18 screening criteria which consist of: (1) percentage of revenue from regulated electric utility
19 operations; (2) the company’s stock must be publicly traded; (3) four consecutive years of

⁴⁹ Roger A. Morin, Ph.D., *New Regulatory Finance*, at 377 (2006).

⁵⁰ PPL Electric Exhibit JEN-16R [EJA Answer to PPL to EJA-I-9].

⁵¹ <https://www.northwesternenergy.com/docs/default-source/default-document-library/about-us/investors/financials/final-bkh---nwe-press-release.pdf>.

⁵² PPL Electric St. No. 10, p. 16.

1 historic earnings data; (4) investment information from more than one source; (5) not being
2 involved in a merger or other business transformation; and (6) operating in a deregulated
3 market.⁵³ Conversely, OCA Witness Garrett adopts my proxy group. The remaining
4 witnesses do not develop proxy groups of comparable companies.

5
6 **Q. Do you have any disagreements with the screening criteria that Mr. Breuning uses to**
7 **select his proxy group for PPL Electric in this proceeding?**

8 A. Yes. My primary area of disagreement is that Mr. Breuning includes a screen to exclude
9 companies that do not operate in deregulated markets. This results in the exclusion of nine
10 companies that are included in my proxy group. Mr. Breuning mentions that companies
11 that own generation assets have a different risk profile than PPL Electric.⁵⁴ If the purpose
12 of Mr. Breuning's screen is to exclude companies that own regulated generation, then the
13 screening criterion he has chosen is misguided and does not accomplish his intended
14 purpose. To that point, 11 of the 16 companies in his proxy group own regulated generation
15 assets, and only 2 of the 16 companies do not own any generation assets.⁵⁵ In addition, not
16 all of the operating subsidiaries held by Mr. Breuning's proxy group provide service to
17 customers in jurisdictions with deregulated electricity markets, meaning that there is not
18 direct comparability between his proxy group and PPL Electric. For example, Duke
19 Energy Corporation, one of Mr. Breuning's proxy group companies, provides electric

⁵³ I&E St. No. 3, p. 8.

⁵⁴ I&E St. No. 3, p. 13.

⁵⁵ CenterPoint Energy Inc., Consolidated Edison Inc., Eversource Energy, Exelon Corp., and Public Service Enterprise Group, Inc. do not own regulated generation assets. Of those, only Eversource Energy and Exelon Corp. do not own any generation.

1 utility service in six states,⁵⁶ only one of which (Ohio) has a deregulated electric utility
2 market. It simply is not possible to construct a proxy group of U.S. electric utility
3 companies that are pure transmission and distribution (“T&D”) companies, because only
4 two companies do not own generation and would consequently pass such a screen. Two
5 companies is not a sufficient number of companies for a proxy group to provide meaningful
6 results.

7 Moreover, I disagree with Mr. Breuning’s decision to screen his proxy group based
8 on the percentage of regulated electric revenue rather than the percentage of regulated
9 operating income. Additionally, Mr. Breuning should have removed NorthWestern Energy
10 from his proxy group, as Black Hills Corp. and NorthWestern Energy announced a merger
11 in August 2025.⁵⁷ Lastly, I disagree with the inclusion of PPL Corporation, the parent
12 company of PPL Electric, in the proxy group due to the circular logic involved with
13 including the parent company in establishing the authorized ROE for one of its operating
14 subsidiaries.

15
16 **Q. Have you evaluated the effect of using Mr. Breuning’s proxy group in your analyses**
17 **as compared to the results from your analyses that use your proxy group?**

18 A. Yes, I have. If I were to instead use Mr. Breuning’s proxy group, my average DCF results
19 would be 10.53 percent (Constant Growth) and 10.76 percent (Quarterly DCF) and my

⁵⁶ Duke Energy Corporation, 2024 Form 10-K, at 10. Duke Energy Corporation provides electric utility service through its subsidiaries in Florida, North Carolina, South Carolina, Indiana, Ohio, and Kentucky.

⁵⁷ Source: <https://northwesternenergy.com/docs/default-source/default-document-library/about-us/investors/financials/final-bkh---nwe-press-release.pdf>.

average CAPM results would be 13.24 percent (forward market risk premium, “MRP”) and 10.38 percent (historical MRP), as summarized in Figure 7 below. In each case, ROE estimates using my proxy group are 6 or 7 basis points lower than the ROE estimates that use Mr. Breuning’s proxy group. My conclusion is that there is no meaningful difference in the overall ROE estimates for PPL Electric regardless of whether my proxy group or Mr. Breuning’s proxy group is used.

Figure 7: Comparison of Proxy Group Results⁵⁸

Model	Nelson Proxy Group	Breuning Proxy Group	Nelson Less Breuning (Bps)
DCF	Constant Growth: 10.46%	Constant Growth: 10.53%	-7
	Quarterly Growth: 10.70%	Quarterly Growth: 10.76%	-6
CAPM	Historical market return: 10.32%	Historical market return: 10.38%	-6
	Forward market return: 13.17%	Forward market return: 13.24%	-7

Q. Please explain why you disagree with Mr. Breuning’s decision to apply a screening criterion based on the percentage of regulated electric revenue rather than the percentage of regulated electric net operating income.

A. Net operating income better reflects the contribution of each business segment to a given company’s earnings, which is the factor that equity investors are most focused on as they

⁵⁸ PPL Electric Exhibits JEN-1R through JEN-4R and PPL Electric Exhibits JEN-9R through JEN-11R.

1 establish their return requirements and make investment decisions. Since regulated electric
2 utilities collect the cost of purchased fuel or power through rates on a pass-through basis
3 without margin, regulated revenue can fluctuate materially from year-to-year with changes
4 in weather and the cost of purchased power/fuel, without affecting the corporation's
5 earnings or financial position. In contrast, net operating income, which excludes pass-
6 through commodity costs, more closely represents the effect of each business segment on
7 the corporation's overall earnings, and therefore its risk profile. For that reason, the
8 percentage of net operating income from regulated electric operations is more
9 representative of the risks faced by PPL Electric and its investors than is the percentage of
10 regulated revenue that Mr. Breuning uses to screen his proxy group. In practice though,
11 this screening criterion does not affect the composition of the proxy group compared to my
12 regulated electric operating income screen.

13
14 **Q. What are your conclusions regarding the composition of the proxy group for PPL**
15 **Electric in this proceeding?**

16 A. My primary conclusion is that the composition of our respective proxy groups is not a
17 primary factor driving the differences in my ROE analyses and recommendation for PPL
18 Electric and those of the Witnesses in this proceeding. While I continue to believe that my
19 proxy group of 23 electric utility companies is more risk comparable to PPL Electric than
20 that of Mr. Breuning, I have limited my rebuttal on this point to focus more attention on
21 the issues that are the key factors underlying our divergent ROE results and

1 recommendations, specifically the models and methodologies to apply and the most
2 appropriate inputs to each of those various financial models.

3
4 **VI. DCF MODEL**

5 **Q. Please summarize the Witnesses' DCF-based ROE estimates.**

6 A. Both I&E Witness Breuning and OCA Witness Garrett perform a Constant Growth DCF
7 analysis to estimate the ROE for PPL Electric in this proceeding. Mr. Breuning relies on
8 analysts' projected earnings per share ("EPS") growth rates, while Mr. Garrett relies on
9 projected dividend per share ("DPS") growth rates from Value Line and projected nominal
10 GDP growth from the Congressional Budget Office. Mr. Breuning relies on the results of
11 his DCF analysis in deriving his ROE recommendation of 10.32 percent, while using the
12 CAPM analysis as a point of comparison. I note that Mr. Breuning did not reference the
13 median (10.50 percent)⁵⁹ of his DCF model results; if he had averaged the median result
14 with his average result, as I do, his DCF estimate and ROE recommendation would be
15 10.41 percent. Mr. Garrett's DCF model produces return estimates ranging from 7.3
16 percent to 8.7 percent, depending on the growth rate he uses. Figure 8 below summarizes
17 Witnesses' ROE estimates using the DCF model. The remaining witnesses do not provide
18 a DCF-based ROE estimate.

⁵⁹ The median 10.50 percent ROE estimate is calculated based on the median of column (3) of I&E Exhibit No. 3, Schedule 14.

Figure 8: Witnesses' DCF Estimates, As Filed

Witness	DCF Range	DCF-based ROE Estimate(s)
I&E Witness Breuning ⁶⁰	Range not specified	10.32%
OCA Witness Garrett ⁶¹	7.3%-8.7%	7.3%, 8.7%

From the outset, I recommend that the Commission not give any weight to Mr. Garrett's DCF-based ROE estimates, as those are below all authorized ROEs for other electric utilities in at least the past 46 years.⁶²

Q. Are there areas of the DCF analysis with which you and the Witnesses agree?

A. Yes. I agree with the analysts' *earnings* growth rate projections that Mr. Breuning uses in his DCF model.⁶³ However, I disagree with Mr. Garrett's reliance on alternative measures of growth, including DPS growth and GDP growth, as discussed below. Further, while Messrs. Breuning and Garrett use slightly different approaches than I do to calculate their respective forward-looking dividend yields in the DCF model, the end results are generally similar. Finally, Mr. Breuning had excluded elevated analyst earnings growth rate projections for Dominion Energy, Inc. ("Dominion"), similar to what I did in my direct testimony. I note that, as of December 31, 2025, Dominion's projected earnings growth

⁶⁰ I&E St. No. 3, I&E Exhibit No. 3, Schedule 14.

⁶¹ OCA St. 3, Exhibit DJG-6.

⁶² Source: RRA. Excludes ROEs authorized for The United Illuminating Co. in case no. 22-08-08 and Central Maine Power Co. in case no. 2018-00194 because they included ROE penalties. Also excludes ROEs authorized for Green Mountain Power Corp., Ameren Illinois, and Commonwealth Edison Co., as these ROEs were set by changes in Treasury bond yields. The framework for setting these ROEs is not comparable to the framework used in setting the ROE that will be authorized for PPL Electric.

⁶³ I&E St. No. 3, pp. 33-34.

1 rates from Zacks and S&P Capital IQ dropped significantly from the 13.60 percent and
2 13.98 percent growth rates, respectively, that Mr. Breuning excluded from his testimony
3 to 10.30 percent and 6.25 percent, respectively; as such, I do not exclude those Dominion
4 growth rates in my rebuttal testimony.

5
6 **Q. According to OCA Witness Garrett, your DCF results are overstated due to your use**
7 **of “average growth rates for the proxy group that are unsustainably high.”⁶⁴ What**
8 **is your response?**

9 A. Both Mr. Breuning and I have used analyst EPS growth rate projections in our DCF models
10 to estimate the ROE for PPL Electric. As explained in my direct testimony, over the long
11 term, dividend growth can only be sustained by earnings growth.⁶⁵ Importantly, when
12 providing guidance to investors regarding the overall total return targets in their investor
13 presentations, companies define the total return as the dividend yield plus *earnings* growth,
14 not dividend or sustainable growth.⁶⁶ Academic studies suggest that investors base their
15 investment decisions on analysts’ expectations of growth in earnings.⁶⁷ I am not aware of
16 any similar findings regarding dividend-based growth estimates. In addition, the only
17 forward-looking growth rates that are available on a consensus basis are analysts’ EPS

⁶⁴ OCA St. 3, p. 27.

⁶⁵ PPL Electric St. No. 10, p. 20.

⁶⁶ See, e.g., American Electric Power Company, Inc., October 29, 2025, AEP Third Quarter 2025 Earnings Presentation, at 6; Duke Energy Corporation, November 7, 2025, Earnings Review and Business Update, at 11; Xcel Energy, October 30, 2025, Earnings Report Presentation, at 23.

⁶⁷ See, e.g., Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, *Financial Management*, Summer 1992, at 65; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, *The Journal of Portfolio Management*, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton’s original conclusions.

1 growth rate projections. Because dividend growth rate projections are only reported by a
2 single source (Value Line), they are more susceptible to potential anomalies than earnings
3 growth rates, which are reported by many sources and generally represent a consensus
4 view. The fact that earnings growth projections are the only widely reported and accepted
5 estimates of growth further supports the finding that earnings growth is the most
6 meaningful measure of growth among the investment community.

7 As I explain in my direct testimony, academic research has shown that analysts'
8 consensus earnings forecasts are better at predicting the valuation of common stocks.⁶⁸ For
9 example, a 2002 study in the Journal of Accounting Research examined "the valuation
10 performance of a comprehensive list of value drivers" and found that "forward earnings
11 explain stock prices remarkably well" and were generally superior to other value drivers
12 analyzed.⁶⁹ A 2012 study from the journal Contemporary Accounting Research found that
13 the sell-side analysts with the most accurate stock price targets were those whom the
14 researchers found to have more accurate earnings forecasts.⁷⁰

15 Further, Mr. Garrett contradicts his own position regarding the sustainability of
16 utility growth rates when he states: "For young, high-growth firms, estimating the growth
17 rate to be used in the model can be especially difficult, and may require the use of multi-
18 stage growth models. For mature, low-growth firms such as utilities, however, estimating

⁶⁸ PPL Electric St. No. 10, p. 20.

⁶⁹ Liu, Jing, et al., "Equity Valuation Using Multiples," Journal of Accounting Research, Vol. 40 No. 1, March 2002.

⁷⁰ Gleason, C.A., et al., "Valuation Model Use and the Price Target Performance of Sell Side Equity Analysts," Contemporary Accounting Research.

1 the sustainable growth rate is more transparent,”⁷¹ and “regulated utilities are already in
2 their ‘sustainable,’ low growth stage.”⁷²

3
4 **Q. Has the Commission previously relied on a DCF model that solely uses analyst EPS**
5 **growth rates as the expected long-term annual growth rate input when determining**
6 **its authorized ROE?**

7 A. Yes. For example, in Columbia Gas of Pennsylvania, Inc.’s (“Columbia Gas”) recent base
8 rate case at Docket No. R-2025-3053499, the Administrative Law Judges (“ALJs”) agreed
9 with a DCF methodology that used “earnings growth rates forecasted by independent
10 professional analysts.”⁷³ The Commission agreed with the ALJs’ conclusion regarding the
11 DCF methodology.⁷⁴

12
13 **Q. Please explain why you disagree with Mr. Garrett’s use of dividend growth rates in**
14 **the DCF model.**

15 A. As explained above and in my direct testimony, over the long term, dividend growth can
16 only be sustained by earnings growth. Additionally, dividend growth depends on
17 management decisions regarding the dividend payout ratio over the near term and may not
18 necessarily reflect the long-term growth prospects of the company. As noted earlier, Value
19 Line is the only source I am aware of that publishes dividend growth rate projections, which

⁷¹ OCA St. 3, p. 21.

⁷² *Id.*, p. 23.

⁷³ *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, Opinion and Order, December 4, 2025, at 225.

⁷⁴ *Id.*

1 supports the conclusion that investors view earnings growth as the most meaningful
2 measure of growth. In other words, if investors relied heavily on projections of dividend
3 growth, more sources would offer that data. As such, the DCF-based ROE estimate that
4 Mr. Garrett calculated using dividend growth rates⁷⁵ should not be given any weight.

5
6 **Q. Please explain why you disagree with Mr. Garrett's use of a projected nominal GDP**
7 **growth rate in the DCF model.**

8 A. No company, or investor, would be satisfied with growth that simply tracks the broader
9 economy. Investors would and do shift capital to more attractive investments. Companies
10 are constantly searching for new avenues of growth and have levers such as capital resource
11 allocation to achieve growth greater than GDP. There is no reason to expect that an
12 individual corporation competing for capital as a going concern will limit its future
13 earnings or dividend growth rate to that of GDP. Limiting growth in the DCF model to
14 long-term GDP is an unfounded constraint.

15 Moreover, using the same growth rate for each of the proxy companies is
16 inconsistent with the DCF model and dividend yields that differ for each proxy company.
17 Stock prices and investors' return requirements are based on expectations of an individual
18 company's growth, which will differ from company to company. Relying on a uniform
19 growth rate for all companies as Mr. Garrett assumes violates the assumptions of the DCF
20 model.

⁷⁵ OCA St. 3, Exhibit DJG-6.

1 In addition, other commissions have decided against using GDP growth in the DCF
2 model. For example, the Florida Public Service Commission noted “[w]e find that [Office
3 of Public Counsel] witness Garrett’s DCF model result of 7.1 percent is not reasonable
4 because it uses the national GDP as the growth rate and does not reflect the growth rate of
5 regulated natural gas utilities, and shall be given little weight.”⁷⁶ Similarly, the North
6 Carolina Utilities Commission noted that “Witness Walters’ ‘generic’ GDP-based growth
7 rate simply does not reflect the real world expected growth of a utility like [Duke Energy
8 Carolinas]. Accordingly, the Commission determines that neither the sustainable growth
9 methodology nor the Multi-Stage DCF should be accorded any weight in this case.”⁷⁷

10
11 **Q. Is there evidence to refute Mr. Garrett’s claim that “the aggregate growth rate of the**
12 **economy [is] typically a limiting factor for the terminal growth rate of the DCF**
13 **model”⁷⁸?**

14 **A.** Yes, I present two analyses that illustrate utility growth is not limited by GDP growth.
15 First, from 2010 through the end of December 2025, the S&P 500 Utilities Index had a
16 compound annual growth rate (“CAGR”) of 6.51 percent, when looking at price-only
17 growth (excluding dividends, which would be comparable to the analyst growth rates used
18 in my DCF analysis, as stock prices are driven by earnings growth over the long-term).⁷⁹

⁷⁶ *In re: Petition for rate increase by Florida City Gas*, Order Granting in Part and Denying in Part Florida City Gas’ Petition for Certain Rate Increases, Docket No. 20220069-GU, June 9, 2023, at 41 (clarification added).

⁷⁷ *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions, Docket No. E-7, Sub 1276, at 203 (clarification added).

⁷⁸ OCA St. 3, pp. 24-25 (clarification added).

⁷⁹ Source: S&P Capital IQ Pro.

This CAGR is much more comparable to the analyst growth rates that I use in my analysis (6.82 percent)⁸⁰ than Mr. Garrett's 3.7 percent GDP growth rate.

Second, utilities' earnings and consequently dividend growth are driven by increased utility investment or rate base that is not necessarily dependent on GDP growth. Utility capital expenditures have been growing at a rate that far exceeds GDP over the past 3-, 5-, and 10-year periods, as can be seen in Figure 9 below.

Figure 9: Compound Annual Growth in Capital Expenditures (2014-2024)⁸¹

	3-yr CAGR (2021-2024)	5-yr CAGR (2019-2024)	10-yr CAGR (2014-2024)
PPL Proxy Group	10.84%	7.13%	8.02%
Total Electric Utility Sector	10.53%	7.19%	7.54%

The analyst average projected EPS growth rates for the proxy group used in my and Mr. Breuning's DCF analyses (6.82 percent and 6.74 percent, respectively)⁸² are in-line with or lower than growth rates in utility capital expenditures over the past 10 years and, therefore, are not overstated. Rather, they are highly consistent with rate base growth, as would be expected. Moreover, these capital expenditure growth rates are much higher than Mr. Garrett's 3.7 percent GDP growth, which indicates that utility growth is not constrained by economic growth. Given the substantial amount of capital that is expected to be invested to facilitate the energy transition,⁸³ it is unlikely that electric utilities are

⁸⁰ PPL Electric Exhibit JEN-1R, column [8], average of proxy group mean and median.

⁸¹ S&P Global Market Intelligence, *Utility Capex Capital Expenditures Update, H1 2025*, March 24, 2025.

⁸² PPL Electric Exhibit JEN-1R, column [8], average of proxy group mean and median; I&E St. No. 3, I&E Exhibit No. 3 Schedule 13.

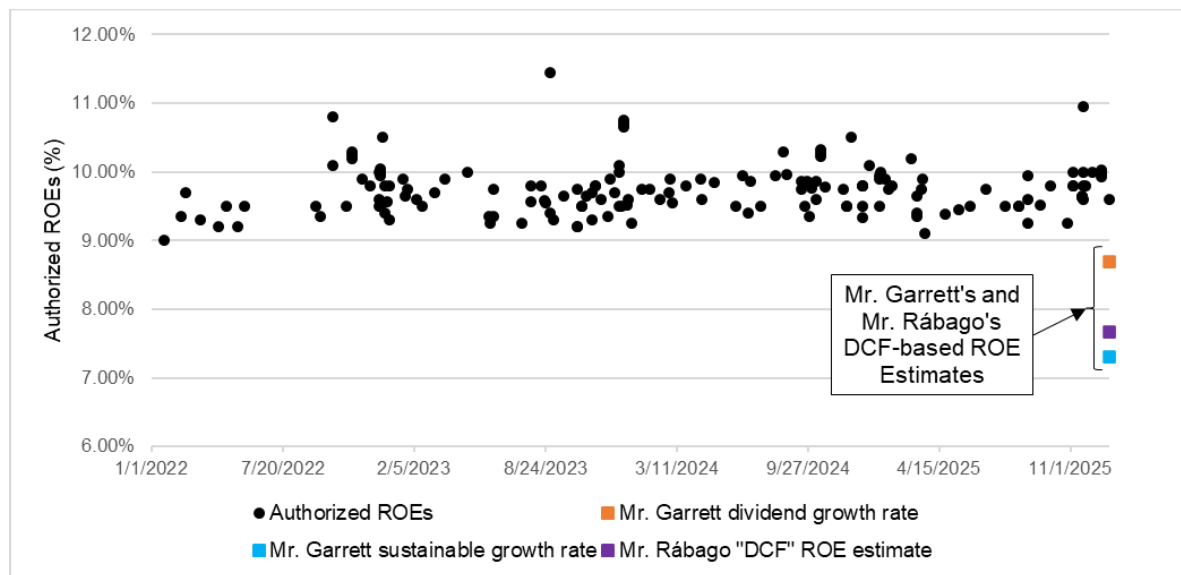
⁸³ See, e.g., PPL Electric Exhibit JEN-6R.

1 nearing the end of their investment cycles; rather, it is likely closer to the beginning of
2 those cycles.

3
4 **Q. Do Mr. Garrett's and Mr. Rábago's DCF-based ROE estimates satisfy the *Hope* and**
5 ***Bluefield* comparable return standard?**

6 A. No, they do not. As can be seen in Figure 10 below, Mr. Garrett's and Mr. Rábago's⁸⁴
7 DCF-based ROE estimates are near the bottom of, or well below, recently authorized ROEs
8 for electric utilities, which is especially problematic given the increase in interest rates over
9 the past few years that I described above.

10 **Figure 10: Mr. Garrett's and Mr. Rábago's DCF-based ROE Estimates vs. Electric**
11 **Utility Authorized ROEs⁸⁵**



⁸⁴ As I explained earlier, Mr. Rábago's ROE estimate is not based on a standard "discounted cash flow calculation" as he claims, though I include it here to demonstrate how much of an outlier his recommendation is.

⁸⁵ Source: RRA, rate case decisions for electric utilities as of December 31, 2025. Excludes decisions with companies that operate under a formula rate plan or decisions with ROE penalties, limited-issue rider cases, and transmission cases.

1
2 **Q. Please summarize your conclusions regarding the Witnesses' DCF models.**

3 A. The Witnesses present several different DCF models with various inputs and results. I
4 recommend that the Commission not give any weight to Mr. Garrett's DCF models, as
5 those results are unjustifiably low and below all authorized ROEs for other electric utilities
6 in at least the past 46 years. If the Commission is to rely on Mr. Breuning's DCF model
7 results, I suggest that the Commission also factor in his median model results (10.50
8 percent) in addition to the average model results (10.32 percent) that he presents, for an
9 overall result of 10.41 percent; using the median adds additional robustness to the ROE
10 estimate as it is less impacted by the highest and lowest individual company estimates.
11 DCF analyses that use analysts' earnings per share growth rates, such as those used by Mr.
12 Breuning and me, produce more reasonable ROE estimates that are more consistent with
13 returns available to other utilities, as the *Hope* and *Bluefield* standards require. However,
14 I disagree with Mr. Breuning's sole reliance on the DCF model to support his ROE
15 recommendation for PPL Electric in this proceeding. As discussed in my direct testimony,
16 it is reasonable and appropriate to consider the results of multiple methodologies, including
17 the DCF, CAPM and Risk Premium models; doing so is consistent with investor practice.⁸⁶
18 Moreover, I continue to believe it is reasonable to also consider the results of the Quarterly
19 DCF model for the reasons discussed in my direct testimony.⁸⁷
20

⁸⁶ PPL Electric St. No. 10, pp. 4, 17, 61.

⁸⁷ PPL Electric St. No. 10, pp. 22-24.

1 **VII. CAPITAL ASSET PRICING MODEL**

2 **Q. Please summarize the Witnesses' CAPM-based ROE estimates.**

3 A. Both I&E Witness Breuning and OCA Witness Garrett perform a CAPM analysis to
4 estimate the ROE for PPL Electric in this proceeding. Mr. Breuning uses a projected yield
5 on the 10-year Treasury bond from Blue Chip Financial Forecasts for his estimate of the
6 risk-free rate, while Mr. Garrett uses the 30-day average yield of the 30-year U.S. Treasury
7 bond. Both witnesses rely on Value Line for Beta coefficients. To determine the equity
8 risk premium ("ERP"),⁸⁸ Mr. Breuning first determines the overall market return by
9 averaging a forward-looking Value Line median return estimate and the average return of
10 the S&P 500 over the past 99 years. Mr. Breuning also provides a second CAPM-based
11 ROE estimate, relying on Kroll's recommended ERP and the 20-Year U.S. Treasury Bond
12 yield. Mr. Garrett arrives at his overall estimate of the ERP by taking the average ERP
13 from four sources: the 2025 IESE Business School Survey, Kroll, Dr. Damodaran's ERP
14 estimate for December 2025, and Mr. Garrett's own implied ERP calculation.⁸⁹ Mr.
15 Breuning estimates a 9.71 percent ROE using a forecasted market return and an 8.36
16 percent ROE using Kroll's recommended ERP. Mr. Garrett's CAPM estimates a cost of
17 equity of 8.4 percent if his recommended 42 percent equity ratio is used. If the Company's
18 recommended equity ratio of approximately 56 percent is used, Mr. Garrett's CAPM
19 estimates a 7.6 percent ROE. Figure 11 below summarizes Mr. Breuning's and Mr.

⁸⁸ In the context of the CAPM, the ERP and MRP are synonymous.

⁸⁹ OCA St. 3, pp. 36-37.

Garrett's ROE estimates using the CAPM model. The remaining witnesses did not provide a CAPM-based ROE estimate.

Figure 11: Witnesses' CAPM Estimates, As Filed

Witness	CAPM Range	CAPM-based ROE Estimate(s)
I&E Witness Breuning ⁹⁰	8.36% - 9.71%	9.04%
OCA Witness Garrett ⁹¹	7.6% - 8.4%	7.6%, 8.4%

From the outset, I recommend that the Commission not give any weight to Mr. Garrett's CAPM-based ROE estimates or Mr. Breuning's CAPM estimate based on Kroll's recommended ERP, as those are below all authorized ROEs for other electric utilities in at least the past 46 years and would not provide PPL Electric the opportunity to earn a comparable return as required by the *Hope* and *Bluefield* standards.

Q. Before responding to the Witnesses' criticisms of your CAPM analysis, are there areas of agreement with respect to your respective CAPM analyses?

A. Yes, there are. First, I agree with Mr. Garrett that the 30-year Treasury bond yield is appropriate to use as the risk-free rate.⁹² Additionally, Mr. Breuning, Mr. Garrett, and I all rely on Value Line Beta coefficients.⁹³

⁹⁰ I&E St. No. 3, pp. 37-39.

⁹¹ OCA St. 3, p. 56; OCA Exhibits DJG-11 and DJG-12.

⁹² OCA St. 3, p. 29.

⁹³ I&E St. No. 3, p. 35; OCA St. 3, p. 30.

1 **Q. Mr. Breuning describes several “shortcomings” associated with the use of the CAPM**
2 **in determining the cost of equity, which leads him to present CAPM results as a**
3 **“comparison, not a check, to the DCF results.”⁹⁴ Please comment on his concerns**
4 **with the CAPM and his decision to exclude it from his ROE recommendation.**

5 **A.** Mr. Breuning contends that the CAPM – and the Risk Premium method via foundational
6 similarities to the CAPM – possess several “disadvantages” that suggest they “should not
7 be given comparable weight to the DCF method.”⁹⁵ More specifically, Mr. Breuning
8 voices concerns with Beta coefficients, the company-specific component of the CAPM, as
9 he believes its reliance on historical data is “problematic” given the nature of current
10 economic conditions. As explained in my direct testimony, while Beta coefficients are
11 ultimately derived from historical market data, other variables, such as a projected risk-
12 free rate and a forward-looking estimate of the market return, help capture the expected
13 impact of current and future economic conditions.⁹⁶ In fact, Mr. Breuning himself uses a
14 projected risk-free rate in his CAPM analysis.⁹⁷ Furthermore, my use of 5-year and 10-
15 year historical Beta coefficients in the CAPM offer a varied look into market conditions,
16 recognizing that the economic and regulatory landscape changes over time. Further, the
17 use of adjusted Beta coefficients like those calculated by Value Line and Bloomberg can
18 be interpreted as forward looking because they correct for the tendency that Beta
19 coefficients move toward the market average of 1.0 over time. For these reasons, I disagree

⁹⁴ I&E St. No. 3, p. 23.

⁹⁵ *Id.*, p. 25.

⁹⁶ PPL Electric St. No. 10, pp. 26-27.

⁹⁷ I&E St. No. 3, p. 36.

1 with Mr. Breuning's conceptual concerns with the CAPM and believe the Commission
2 should ultimately factor the CAPM into determining the Company's ROE. However, for
3 reasons described below, Mr. Breuning's and Mr. Garrett's approaches to the CAPM are
4 flawed and should not be given weight in the Commission's decision.

5
6 **Q. Mr. Breuning disagrees with the Commission's recent use of the CAPM method.⁹⁸**
7 **What is your response?**

8 A. Mr. Breuning highlights several recent decisions from the Commission in which the CAPM
9 was utilized as a method to establish a utility ROE. For example, Mr. Breuning focuses on
10 the 2024 base rate case order for Columbia Water Company, in which the Commission
11 ultimately relied on the average of the I&E Witness's CAPM and DCF results to determine
12 the ROE for Columbia Water Company.⁹⁹ In a subsequent rate case for Pennsylvania-
13 American Water Company, the Commission recognized continued capital market
14 conditions (i.e., elevated inflation) while determining to employ both the DCF and CAPM
15 models in setting the ROE for Pennsylvania-American Water Company. As mentioned
16 previously, the key factors affecting the cost of equity, including those previously
17 acknowledged by the Commission, for regulated utilities in both current and prospective
18 capital markets are still present. These factors, as explained in my direct testimony,¹⁰⁰

⁹⁸ *Id.*, pp. 27-28.

⁹⁹ *Pa. PUC v. Columbia Water Company*, Docket No. R-2023-3040258, at 105 (January 18, 2024).

¹⁰⁰ PPL Electric St. No. 10, p. 61.

1 stress the need for multiple models, including the CAPM, to obtain a comprehensive
2 perspective on the cost of equity for PPL Electric.

3
4 **A. Risk-Free Rate of Return**

5 **Q. Mr. Breuning uses the projected yield on 10-year Treasury bonds to estimate the risk-**
6 **free rate, as he believes it balances the short-term volatility of T-Bills and the**
7 **“substantial maturity risk” associated with long-term Treasury bonds.¹⁰¹ What is**
8 **your response?**

9 A. I respectfully disagree with Mr. Breuning’s use of 10-year Treasury bonds to serve as the
10 risk-free rate for the CAPM and his concerns surrounding the use of 30-Year Treasury
11 bonds. In determining the security most relevant to the application of the CAPM, it is
12 important to select the term that best matches the life of the underlying investment. As
13 explained by Morningstar:

14 The traditional thinking regarding the time horizon of the chosen
15 Treasury security is that it should match the time horizon of
16 whatever is being valued... Note that the horizon is a function of
17 the investment, not the investor. If an investor plans to hold stock
18 in a company for only five years, the yield on a five-year Treasury
19 note would not be appropriate since the company will continue to
20 exist beyond those five years.¹⁰²

21 Since utility assets are long-duration investments, it is appropriate to use yields on
22 long-term Treasury bonds as the risk-free rate component of the CAPM. Therefore, the
23 30-year Treasury bond is the most appropriate security for that purpose.

¹⁰¹ I&E St. No. 3, pp. 36-37.

¹⁰² Morningstar Inc., Ibbotson SBBI 2013 Valuation Yearbook, at 44.

1
2 **Q. Mr. Breuning claims that “the 30-year Treasury Bond exhibits more stability but is**
3 **not risk-free”¹⁰³ when discussing his risk-free rate estimate. What is your response?**

4 A. I agree with Mr. Breuning’s stance that the 30-year Treasury bonds “exhibit more
5 stability”; as described by Dr. Roger Morin, “On grounds of stability and consistency, the
6 yields on long-term Treasury bonds match more closely with expected common stock
7 returns.”¹⁰⁴ However, Mr. Breuning’s claim that 30-year Treasury bonds are “not risk-
8 free” incorrectly comingles two types of risk: default risk and interest rate risk. Because
9 long-term Treasury bonds are backed by the U.S. government, they are essentially free of
10 default risk. Furthermore, as Dr. Morin goes on to explain, “While long-term Treasury
11 bonds are potentially subject to interest rate risk, and are not theoretically ‘risk-free,’ this
12 is only true if the bonds are sold prior to maturity. A substantial fraction of bond market
13 participants, usually institutional investors with long-term liabilities (pension funds,
14 insurance companies), in fact, hold bonds until they mature, and therefore are not subject
15 to interest rate risk.”¹⁰⁵ Given that investments in any government security will have some
16 theoretical level of interest rate risk, as rates can change over time, it is important to
17 consider the practical level of risk for such investments. Thus, given that the 30-year
18 Treasury bond is a stable security free of default risk, has minimal real interest rate risk,
19 and aligns with the life of the underlying investment in utility assets, as described above,
20 it serves as an appropriate security for the risk-free rate component of the CAPM.

¹⁰³ I&E St. No. 3, p. 36.

¹⁰⁴ Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 152 (2006).

¹⁰⁵ *Id.*

B. Beta Coefficient

Q. What is your response to Mr. Garrett’s alternate beta using the Hamada Model to estimate an “unlevered” beta, and then “relevering” the Beta at a different debt ratio?¹⁰⁶

A. Mr. Garrett developed an alternative Beta coefficient estimate by unlevering and relevering the Beta coefficient using the book value of debt and equity to arrive at a relevered Beta coefficient of 0.58, based on the capital structure of the proxy group consisting of 44 percent debt and 56 percent equity. However, Mr. Garrett’s approach is incorrect. The Hamada adjustment is typically applied to the market value of a company’s capital structure, not the book value.¹⁰⁷ Further, the Beta coefficient is a market parameter that is based on the relative volatility and correlation of a company’s *market value* stock price against the overall market index (which is also priced at market value). Relevering the Beta coefficient with *book value* leverage mixes measurement bases and distorts the Beta coefficient (and thus the cost of equity and WACC). Because the proxy companies’ equity on a market value basis is greater than the book values of equity,¹⁰⁸ a properly applied Hamada adjustment should result in an *upward* adjustment to the ROE, not a *downward* adjustment. For those reasons, Mr. Garrett’s Hamada adjustment is misapplied and should be rejected.

¹⁰⁶ OCA St. 3, pp. 54-56.

¹⁰⁷ Hamada’s original research relied on market values for common equity and debt. See, Hamada, Robert S., “The Effect of the Firm’s Capital Structure on the Systematic Risk of Common Stocks,” The Journal of Finance, vol. 27, no. 2, 1972, pp. 435–52.

¹⁰⁸ See, e.g., PPL Electric Exhibit JEN-7 (Page 1) which shows that the proxy companies’ market to book ratios are all above 1.0.

C. Market Risk Premium

Q. Please summarize the Witnesses' approach for determining the market risk premium.

A. As previously mentioned, Mr. Breuning takes two approaches to determining the market risk premium. First, Mr. Breuning averages a forward-looking and historical estimate of the market return, from which he subtracts his estimate of the risk-free rate to arrive at an estimated MRP. To conduct the forward-looking market return approach, Mr. Breuning relies on the October 17, 2025, edition of the *Value Line Investment Survey*, covering roughly 1,700 companies in the Value Line universe. From this report, he combines a 2.10% median forecasted dividend yield for all dividend-paying companies with a growth rate of 8.78%, derived from a median estimated three-to-five year stock price appreciation potential of 40% for all companies. Mr. Breuning averages this expected market return of 10.88% with the average annual return of the S&P 500 over the last 99 years, 12.29%, to arrive at his market return estimate of 11.59%. Additionally, Mr. Breuning provides a second MRP estimate, relying on Kroll's recommended Market Risk Premium of 5.00%.¹⁰⁹ Mr. Garrett's MRP is determined by averaging the MRP from four sources: the 2025 IESE Business School Survey, Kroll, Dr. Damodaran's ERP estimate for December 2025, and Mr. Garrett's own implied market risk premium method.

As Mr. Garrett describes, his implied market risk premium method develops the internal rate of return that sets the current value of the market index equal to the projected

¹⁰⁹ I&E St. No. 3, p. 38.

1 value of cash flows associated with owning the market index. Mr. Garrett's method is a
2 two-stage form of the DCF model, which calculates the present value of cash flows over
3 the five-year initial period, together with the terminal price (based on the Gordon
4 Model¹¹⁰), to be received in the last (*i.e.*, terminal) year.

5 Ultimately, Mr. Garrett calculates an MRP estimate of 5.0% from his implied MRP
6 method. When averaged with the three additional MRP estimates, Mr. Garrett arrives at
7 an overall MRP estimate of 4.9%.¹¹¹

8
9 **Q. Do you have any concerns with Kroll's recommended equity risk premium estimate**
10 **that I&E Witness Breuning and OCA Witness Garrett reference?**¹¹²

11 A. Yes, I do. I disagree with Kroll's recommended equity risk premium. My primary concern
12 is that it is not clear that Kroll develops its market risk premium in relation to its risk-free
13 rate. The market risk premium is calculated as the difference between the expected market
14 return and risk-free rate; therefore, it is a function of the expected market return and risk-
15 free rate at a point in time. Consequently, the market risk premium and risk-free rate are
16 not independent of each other; they are interrelated. In fact, academic studies have shown
17 that the two are inversely related.¹¹³ As the risk-free rate decreases, the market risk
18 premium increases and vice versa. However, as shown in Figure 12 below, there is no
19 clear relationship between Kroll's recommended equity risk premium and risk-free rate.

¹¹⁰ OCA St. 3, p. 34.

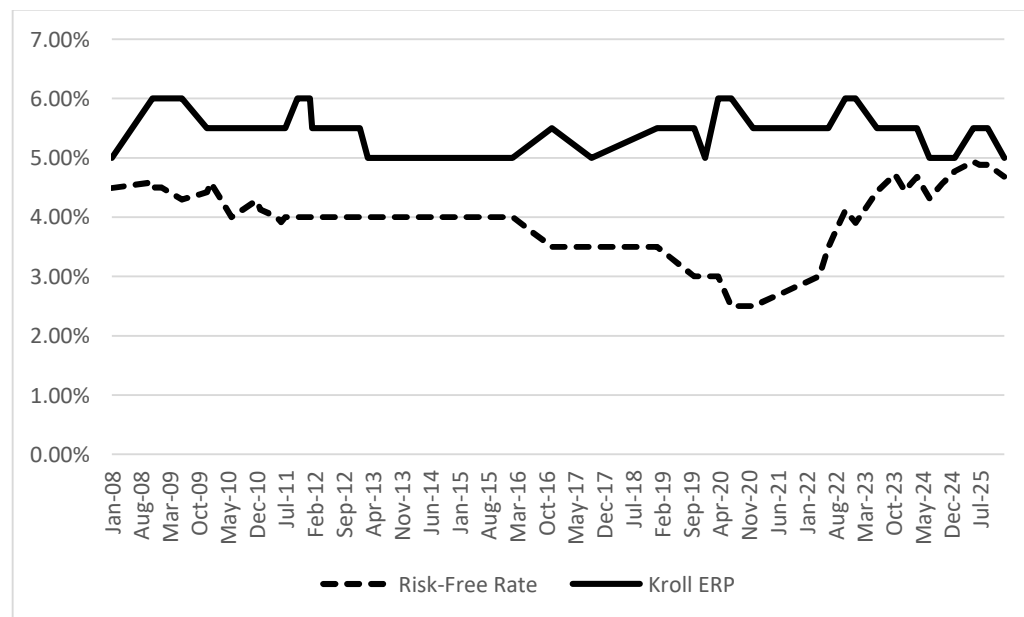
¹¹¹ OCA St. 3, Exhibit DJG-10.

¹¹² I&E St. No. 3, p. 38; OCA St. 3, p. 37.

¹¹³ See, *e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70.

Whereas academic studies indicate that the two lines should move in opposite directions, Figure 12 shows they do not.

Figure 12: Kroll Recommended Equity Risk Premium and Risk-Free Rate (2008-2025)¹¹⁴



The conclusion that there is no clear relationship between Kroll's variables is supported by statistical analysis. To assess whether there is a relationship, I performed a linear regression in which Kroll's recommended equity risk premium was the dependent variable and the recommended risk-free rate was the independent variable. The R-square was 0.0093, which means that Kroll's risk-free rate explains only 0.9 percent - virtually none - of the change in the Equity Risk Premium. This runs counter to the fundamental principle that the MRP is a function of the risk-free rate, as noted earlier. Moreover, the slope coefficient is not statistically significant, which means there is little confidence in the

¹¹⁴ Sources: Kroll Cost of Capital Navigator, Federal Reserve Bank of St. Louis FRED Economic Data.

1 statistical results. This is not to suggest that Kroll is not a valid or credible source of data.
2 Rather, it suggests that the usefulness of Kroll's equity risk premium recommendation at
3 the current time is questionable given that it runs counter to academic and financial theory.
4

5 **Q. Have other commissions rejected Kroll's recommended equity risk premium as an**
6 **input to the CAPM?**

7 A. Yes, they have. For example, in Order No. PSC-2023-0177-FOF-GU, the Florida Public
8 Service Commission found that the "use of Kroll's ERP and the results of the CAPM using
9 that data are unreasonable."¹¹⁵ Additionally, in Docket No. E-7 Sub 1276, the North
10 Carolina Utilities Commission similarly concluded that the "use of Kroll's 5.5% MRP fails
11 the test of *Bluefield/Hope*, in that it does not meet the test of comparable return."¹¹⁶ In
12 conclusion, while I recognize that the Commission gave weight to Kroll's recommended
13 ERP in its recent Order for Columbia Gas,¹¹⁷ I respectfully disagree with that finding and
14 recommend that the Commission should not give any weight to Kroll's ERP when
15 calculating the CAPM-based ROE estimate in this case.
16

¹¹⁵ Florida Public Service Commission Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*, Order No. PSC-2023-0177-FOF-GU, at 43 (June 9, 2023).

¹¹⁶ *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 208.

¹¹⁷ *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2025-3053499, Opinion and Order, December 4, 2025, at 234-235.

1 **Q. Do you agree with how Mr. Breuning calculated his 10.88 percent Value Line**
2 **forward-looking market return?**¹¹⁸

3 A. No, I do not. As a preliminary matter, Mr. Breuning is not correct when he notes that
4 “Value Line expects its universe of approximately 1700 stocks to have an *average* yearly
5 return of 10.88% over the next three to five years based on a forecasted dividend yield of
6 2.10% and a yearly index appreciation of 40%.”¹¹⁹ As Value Line’s Summary & Index
7 report clearly states, the 2.10 percent and 40 percent are “The *Median* of Estimated
8 Dividend Yields (next 12 months) of all dividend paying stocks” and “The *Median*
9 Estimated Three-To-Five Year Price Appreciation Potential of all stocks in the VL
10 Universe”, respectively.¹²⁰ When an investor invests in the overall market (which is being
11 approximated here by the Value Line universe of stocks), they receive the *weighted*
12 *average* market return, not the *median* market return. If Mr. Breuning were to use the
13 average as he stated, his result would be higher, as I demonstrate later in Section VII.E (see
14 also PPL Electric Exhibit JEN-12R), where I present my recommended adjustments to Mr.
15 Breuning’s CAPM analysis. Adjusting Mr. Breuning’s CAPM analysis to use the *weighted*
16 *average* market return (without any other corrections) produces an ROE estimate of 11.57
17 percent.¹²¹

¹¹⁸ I&E St. No. 3, p. 37.

¹¹⁹ *Id.* (emphasis added).

¹²⁰ The Value Line Investment Survey, Part 1 Summary & Index, January 16, 2026, at 1 (emphasis added).

¹²¹ As shown on PPL Electric Exhibit JEN-12R, I adjust both the dividend yield and growth rate to use the weighted average rather than the median.

1 **Q. What is your concern with the use of surveys such as the IESE Business School Survey**
2 **considered by Mr. Garrett?**

3 A. My concern is that surveys are often ambiguous and not clearly designed to have
4 confidence that the responses are based on a uniform baseline understanding of what is
5 being surveyed. Analysts are likely to give different responses regarding the expected
6 market return or equity risk premium depending on whether they are considering short or
7 long periods, the current market environment, the risk-free rate that is assumed, real vs.
8 nominal returns, arithmetic vs. geometric returns, and the prevailing point in the economic
9 cycle (expansion vs. contraction; high vs. low inflation, etc.). In other words, we cannot
10 verify respondents' inputs and assumptions to assess whether the responses are
11 comparable. In fact, recognizing the limitations of the survey, the authors explicitly state
12 that the average of the distribution of survey responses "cannot be interpreted as the
13 [Required Equity Premium ("REP")] of the market nor as the REP of a representative
14 investor."¹²²

15
16 **Q. Turning to Mr. Garrett's implied market risk premium method, do you have any**
17 **observations regarding Mr. Garrett's assumed first-stage growth rate?**

18 A. Yes. Mr. Garrett's 6.96 percent growth rate relates only to geometric (or compound)
19 growth in operating earnings and does not reflect capital appreciation or growth in
20 dividends or stock buy backs.¹²³ If Mr. Garrett's position is that historical growth rates are

¹²² Fernandez, Pablo; Garcia, Diego; and Acin, Lucia F.. "Survey: Market Risk Premium and Risk-Free Rate used for 54 countries in 2025," at 9. IESE Business School (clarification added).

¹²³ OCA St. 3, Exhibit DJG-9.

1 meant to reflect expected growth, they should reflect year-to-year variation (that is,
2 uncertainty). That is best accomplished using the arithmetic average growth rate rather
3 than the compound growth rate.
4

5 **Q. How did Mr. Garrett develop his assumed terminal growth rate?**

6 A. The terminal growth rate represents investors' expectations of the rate at which the broad
7 stock market will grow, in perpetuity, beginning in the terminal stage. Mr. Garrett assumes
8 terminal growth, beginning six years from now and extending indefinitely into the future,
9 is equal to the average yield on 30-year Treasury securities over the 30 days ended
10 December 10, 2025.
11

12 **Q. Is Mr. Garrett's terminal growth rate assumption of 4.71 percent reasonable?**

13 A. No, it is not. Mr. Garrett followed Dr. Damodaran's approach to use the risk-free rate as
14 the terminal growth rate.¹²⁴ In terms of historical experience, over the long term, the broad
15 economy has grown at a long-term compound average growth rate of approximately 6.11
16 percent.¹²⁵ For another perspective, the long-term average rate of price appreciation on
17 large company stocks between 1928 and 2025 is 8.10 percent.¹²⁶

¹²⁴ OCA St. 3, pp. 35-36.

¹²⁵ Source: Bureau of Economic Analysis for the years 1929 to 2024.

¹²⁶ S&P Capital IQ. Price appreciation measured at the end of each calendar year.

1 Assuming long-term inflation will be approximately 2.10 percent¹²⁷ implies
2 perpetual real growth will be quite low.¹²⁸ That is, Mr. Garrett's terminal growth rate of
3 4.71 percent assumes that real growth will be close to just 2.56 percent in perpetuity.
4 Nowhere in his testimony has Mr. Garrett explained that investors expect real growth of
5 2.56 percent for riskier equities in perpetuity. Given that equities are riskier than
6 government bonds, it is highly improbable that investors' return requirements would be
7 based on expected growth at a rate equal to the risk-free rate in perpetuity.

8
9 **Q. Have actual observed Market Risk Premia been consistent with the Market Risk**
10 **Premia estimates produced by Dr. Damodaran?**

11 **A.** No, they have not. As shown in Figure 13 below, Dr. Damodaran's annual implied market
12 risk premium has been far removed from actual observed market risk premia in recent
13 years. Moreover, the average actual MRP over the past 15 years, 11.92 percent, is much
14 closer to the highest MRP that I use in my rebuttal CAPM models, 11.34 percent,¹²⁹ than
15 any of the MRPs that Mr. Breuning or Mr. Garrett use.

¹²⁷ For example, in line with the Federal Reserve's target rate of inflation. *See also*, Garrett Exhibit DJG-5. Inflation estimated by subtracting real GDP of 1.6 percent (row ([1]) from Nominal GDP of 3.7 percent (row [2])

¹²⁸ $2.56\% = [(1.0471/1.021)-1]$.

¹²⁹ PPL Electric Exhibit JEN-4R.

Figure 13: NYU Annual Implied vs. Observed Market Risk Premium¹³⁰

Year	NYU Implied Market Risk Premium	Actual Market Risk Premium
2010	5.20%	10.81%
2011	6.01%	-1.71%
2012	5.78%	13.54%
2013	4.96%	29.51%
2014	5.78%	10.28%
2015	6.12%	-1.09%
2016	5.69%	9.66%
2017	5.08%	19.16%
2018	5.96%	-7.20%
2019	5.20%	28.94%
2020	4.72%	16.98%
2021	4.24%	26.98%
2022	5.94%	-20.72%
2023	4.60%	22.44%
2024	4.33%	21.28%
Average	5.31%	11.92%

Q. What is your response to Mr. Garrett’s position that your market risk premium estimate is too high?¹³¹

A. I disagree with that position. First, I do not rely solely on my forward-looking MRP. As explained in my direct testimony, the low end of my recommended range is supported by the CAPM results using a long-term average historical market return.¹³² Nevertheless, the

¹³⁰ Sources: https://pages.stern.nyu.edu/~adamodar/New_Home_Page/home.htm; Kroll, 2023 SBBI Yearbook, Appendix A-1 and A-7 (years 1926-2022); Cost of Capital Navigator (2023-2024 data).

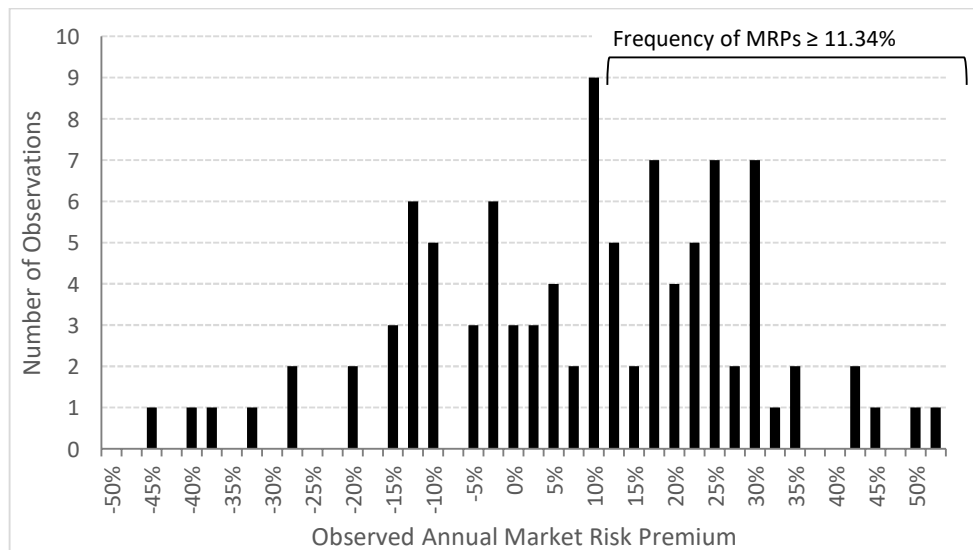
¹³¹ OCA St. 3, p. 39.

¹³² PPL Electric St. No. 10, p. 5.

use of a forward-looking or projected MRP is reasonable because the cost of equity is forward-looking and each of the CAPM components is meant to be a forward-looking parameter.

Second, as discussed in my direct testimony, market returns in the range of my forward-looking market return estimates have occurred quite frequently.¹³³ For an additional perspective, I also reviewed the frequency of the highest MRP presented in my rebuttal testimony, 11.34 percent.¹³⁴ As shown in Figure 14 below, MRPs in the range of 11.34 percent or higher have occurred in 43 of the past 99 years (43.4 percent of the time). From that perspective, the forward-looking market risk premium estimates are not unreasonably high.

Figure 14: Frequency of Observed Market Risk Premia – 1926-2024¹³⁵



¹³³ PPL Electric St. No. 10, p. 28.

¹³⁴ PPL Electric Exhibit JEN-4R.

¹³⁵ Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7.

1 Moreover, because market returns historically have been volatile, my market return
2 estimates are statistically indistinguishable from the long-term historical arithmetic
3 average market return.¹³⁶ As such, my projected market return estimates are reasonable
4 and consistent with historically observed market returns.

5 Finally, my updated Value Line projected market return that I use in my CAPM
6 analyses, 15.95 percent, is conservative, as it is considerably lower than the 18.82 percent
7 and 18.64 percent projected market returns that Bloomberg and S&P estimate,
8 respectively.¹³⁷ In conclusion, there is significant evidence that my forward-looking
9 market return and corresponding MRP are reasonable and should be given full weight by
10 the Commission.

11
12 **D. Empirical CAPM Analysis**

13 **Q. Please summarize the Witnesses' concerns with your empirical CAPM ("ECAPM")**
14 **analysis.**

15 A. Mr. Breuning objects to my use of the ECAPM, contending that the "ECAPM reduces the
16 purpose of the beta, which is the only company-specific variable in the model."¹³⁸ He also
17 claims that the ECAPM is subjective and is not aware of the ECAPM being used as an
18 accepted methodology by regulatory commissions.¹³⁹

¹³⁶ The standard deviation of the observed market return and market risk premium is approximately 19.70 percent and 19.80 percent, respectively. Source: Kroll Cost of Capital Navigator.

¹³⁷ PPL Electric Exhibit JEN-3R.

¹³⁸ I&E St. No. 3, p. 45.

¹³⁹ *Id.*

1 **Q. How do you respond to Mr. Breuning’s concerns?**

2 A. Mr. Breuning’s concerns are misplaced, and his criticism of the CAPM’s performance in
3 “predicting actual returns”¹⁴⁰ further supports the use of the ECAPM in determining the
4 Company’s cost of equity. As explained in my direct testimony, the ECAPM reflects
5 published research that companies with lower Beta coefficients tend to have higher returns
6 than those predicted by the CAPM, and those with higher Beta coefficients tend to have
7 lower returns than expected.¹⁴¹ Beta coefficient adjustments such as those used by Value
8 Line, on the other hand, address the tendency of “raw” Beta coefficients to regress toward
9 the market mean of 1.00 over time. As explained below, the ECAPM is not an adjustment
10 to the Beta coefficient; the two are different issues and are addressed with different
11 methods.¹⁴²

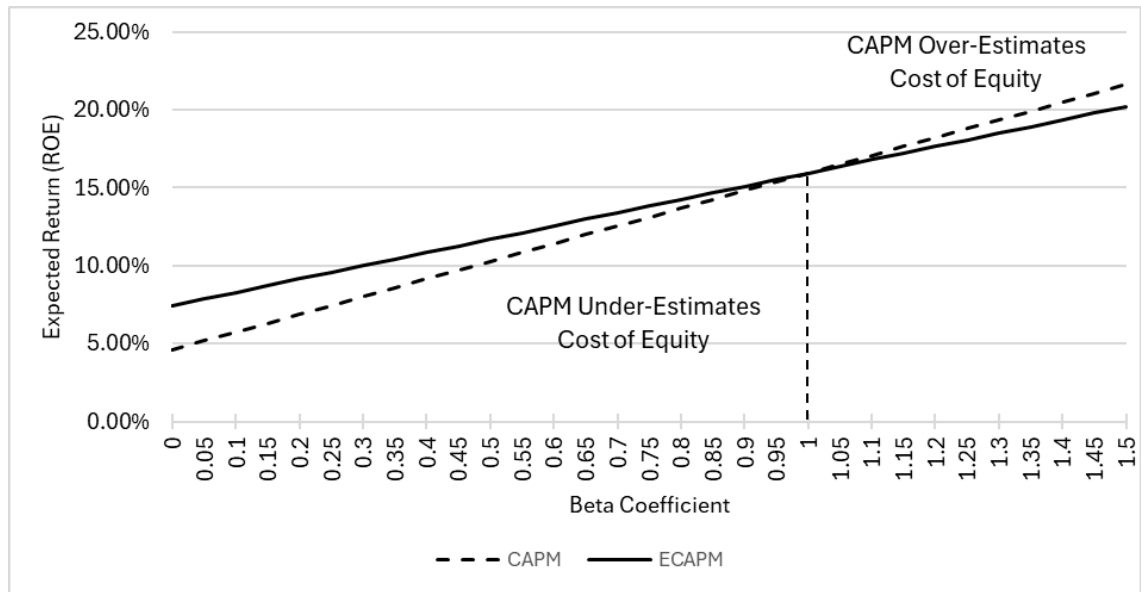
12 The relationship between expected returns from the CAPM and ECAPM can be
13 seen in Figure 15, below. As an example, Figure 15 reflects my projected risk-free rate
14 and forward-looking market risk premium and illustrates the extent to which the CAPM
15 under-states the expected return relative to the ECAPM when Beta coefficients, whether
16 adjusted or unadjusted, are less than 1.00.

¹⁴⁰ I&E St. No. 3, p. 26.

¹⁴¹ PPL Electric St. No. 10, p. 30; *see also* Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 175-176 (2006).

¹⁴² Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 191 (2006).

Figure 15: CAPM and ECAPM Expected Returns



The ECAPM is an adjustment to the risk/return line which, as shown in Figure 15 above, is flatter than the CAPM assumes. That adjustment is required even with the use of adjusted Beta coefficients, such as those provided by Value Line. As Dr. Morin observes (emphasis added):

*Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing...Both adjustments are necessary.*¹⁴³

¹⁴³ Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 191 (2006) (emphasis added).

1 **Q. Mr. Breuning states that he is “not aware of any instances where a utility commission**
2 **overseeing base rate proceedings explicitly relied on the ECAPM when determining**
3 **an appropriate cost of equity for a regulated utility.”¹⁴⁴ Is the ECAPM an accepted**
4 **methodology?**

5 **A.** Yes, it is. I am aware that the ECAPM (sometimes referred to as the “Zero Beta CAPM”)
6 has been accepted by regulatory commissions in Alaska, Maryland, Mississippi, New
7 York, and North Carolina.¹⁴⁵ Additionally, I am aware the ECAPM has been presented by
8 state regulatory commission staff in Maryland and Nevada and by the Department of
9 Commerce in Minnesota.¹⁴⁶

10 For example, the ECAPM is the preferred CAPM methodology and is explicitly
11 relied on by the New York Public Service Commission including the use of adjusted Beta

¹⁴⁴ I&E St. No. 3, p. 45.

¹⁴⁵ See Regulatory Commission of Alaska, Docket No. P-97-4, Order No. 151, at 146; Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 105; Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 19; New York Public Service Commission, Case 16-G-0058, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; *In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40; *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 209-210; *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163.

¹⁴⁶ See Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 88; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *Findings of Fact, Conclusions of Law, and Recommendation*, August 19, 2016, at 29; Public Utilities Commission of Nevada, Docket No. 12-02019, Second Modified Final Order, at 36.

1 coefficients.¹⁴⁷ Additionally, the North Carolina Utilities Commission accepted the
2 ECAPM in Duke Energy Carolinas' and Duke Energy Progress' most recent completed
3 rate cases, including the use of adjusted Beta coefficients in the ECAPM.¹⁴⁸ Consequently,
4 I believe the ECAPM is a reasonable approach and should be considered by the
5 Commission.

6
7 **E. Witness CAPM Adjustments and Conclusion**

8 **Q. Can adjustments be made to Mr. Breuning's CAPM analysis to produce more**
9 **reasonable results?**

10 A. Yes. As I explained previously, from the outset, I recommend the Commission not give
11 any weight to Mr. Garrett's CAPM-based ROE estimates or Mr. Breuning's Kroll CAPM
12 ROE estimate. Accordingly, I do not make adjustments to these estimates. However,
13 modest adjustments can be made to several inputs to Mr. Breuning's "forecasted CAPM
14 analysis"¹⁴⁹ to produce more reasonable results. First, solely replacing Mr. Breuning's use
15 of a projected yield on the 10-year U.S. Treasury Note with my projected yield on the 30-
16 year U.S. Treasury Bond¹⁵⁰ increases his CAPM ROE estimate by 13 basis points.

¹⁴⁷ See, e.g., New York Public Service Commission, Case 16-G-0058, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32.

¹⁴⁸ *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 209-210; *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163.

¹⁴⁹ I&E St. No. 3, pp. 36-37.

¹⁵⁰ See PPL Electric Exhibit JEN-4R.

Additionally, I have adjusted Mr. Breuning's Value Line-based estimate of the expected market return (" R_m ") to combine the weighted average growth rate and dividend yield (as opposed to the median growth rate and dividend yield that Mr. Breuning used) for the 1,352 Value Line companies that have available both projected 3-5 year EPS growth rates and market capitalization data. As shown in PPL Electric Exhibit JEN-12R, using the weighted average estimates, instead of the median data that Mr. Breuning uses, brings the CAPM ROE estimate from 9.71 percent to 11.57 percent. Incorporating both adjustments together, as shown below in Figure 16, raises the CAPM ROE estimate of Mr. Breuning's forecasted CAPM analysis from 9.71 percent to 11.70 percent, or by nearly 200 basis points.

Figure 16: Mr. Breuning's Adjusted CAPM Results¹⁵¹

Adjusted CAPM Input(s)	As Filed	Adjusted	Adjusted CAPM ROE	CAPM ROE Impact
Risk-free Rate	4.08%	4.60%	9.84%	+13bp
Value Line Estimated R_m	10.88%	15.86%	11.57%	+186bp
Risk-free Rate and Value Line Estimated R_m	4.08% and 10.88%	4.60% and 15.86%	11.70%	+199bp

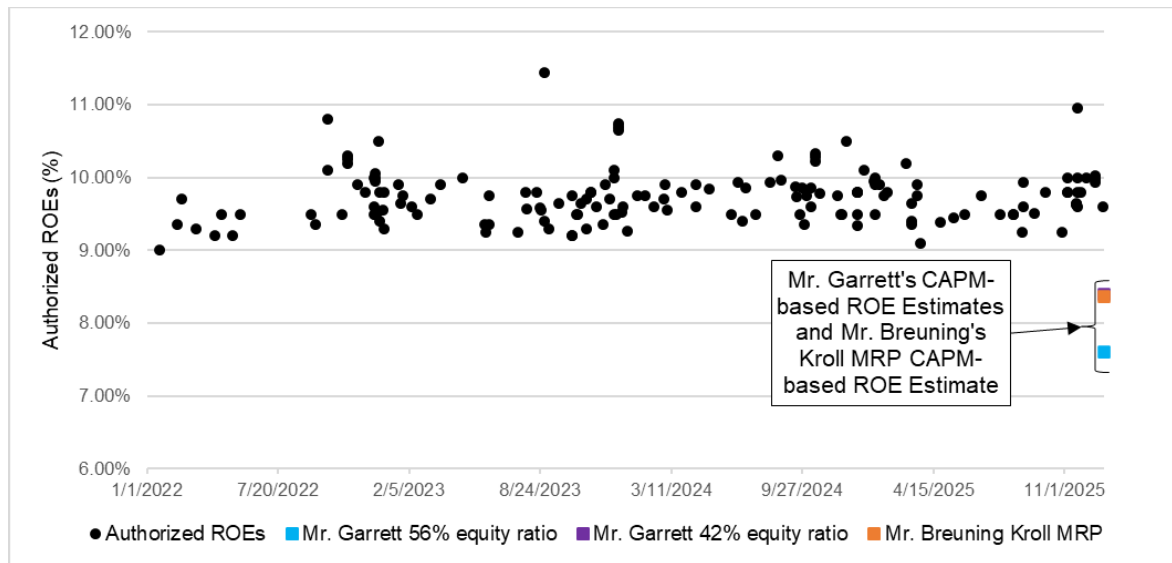
Q. Do Mr. Garrett's CAPM-based ROE estimates and Mr. Breuning's Kroll MRP CAPM ROE estimate satisfy the *Hope* and *Bluefield* comparable return standard?

A. No, they do not. As can be seen in Figure 17 below, Mr. Garrett's CAPM-based ROE estimates and Mr. Breuning's Kroll MRP CAPM-based ROE estimate are near the bottom

¹⁵¹ PPL Electric Exhibit JEN-12R.

of, or well below, recently authorized ROEs for electric utilities, which is especially problematic given the increase in interest rates over the past few years that I describe above.

Figure 17: Mr. Garrett’s CAPM-based ROE Estimates and Mr. Breuning’s Kroll MRP CAPM-based ROE Estimate vs. Electric Utility Authorized ROEs¹⁵²



Q. What is your conclusion with regard to the CAPM?

A. My conclusion is that using sound inputs for the risk-free rate and MRP, along with current Beta estimates from Value Line and Bloomberg, the CAPM is producing reasonable results that should be considered along with the results from the DCF and Risk Premium models. Mr. Breuning’s and Mr. Garrett’s CAPM analyses have multiple flaws or produce ROE estimates below all authorized ROEs for other electric utilities in at least the past 46 years

¹⁵² Source: RRA, rate case decisions for electric utilities as of December 31, 2025. Excludes decisions with companies that operate under a formula rate plan or decisions with ROE penalties, limited-issue rider cases, and transmission cases. Note that Mr. Garrett’s 42 percent equity ratio and Mr. Breuning’s Kroll MRP CAPM-based ROE estimates visually overlap.

1 and should be disregarded. With reasonable adjustments, Mr. Breuning's CAPM results
2 are in line with the CAPM results that I present.

3
4 **VIII. BOND YIELD PLUS RISK PREMIUM MODEL**

5 **Q. I&E Witness Breuning, OCA Witness Garrett, and EJA Witness Rábago challenge**
6 **the use of a Risk Premium model such as the one you have presented, or they contend**
7 **that your application of the Risk Premium model is not reasonable. What are their**
8 **concerns, and how do you respond to those concerns?**

9 A. Mr. Breuning, Mr. Garrett, and Mr. Rábago have expressed three primary concerns
10 regarding my Risk Premium analysis: (1) likening it to the CAPM, which is a
11 misunderstanding of the purpose or function of the Risk Premium model; (2) that the
12 analysis is a gauge of regulatory commission behavior, not investor behavior (i.e., is not
13 market-based and dependent on authorized ROEs); and (3) that the use of historical data in
14 the Risk Premium model is not forward looking.¹⁵³

15 Regarding the first concern, my Risk Premium analysis determines the appropriate
16 risk premium based on the relationship between historical authorized ROEs for integrated
17 electric utilities and Treasury bonds yields over the last 46 years. As shown in PPL Electric
18 Exhibit JEN-5R, my Risk Premium analysis is supported by a regression equation that
19 evaluates the relationship between Treasury bond yields and the equity risk premium over
20 time. The regression equation has an R^2 of 0.7647, which indicates that there is a high
21 degree of correlation between the change in the equity risk premium and changes in interest

¹⁵³ I&E St. No. 3, pp. 22, 25, 29, 43-44; OCA St. 3, p. 41; EJA St. No. 1, p. 24.

rates, making the model a reliable predictor of the equity risk premium at various levels of interest rates. This is a highly statistically significant relationship, and an intuitive one, reflecting the change in the equity risk premium in response to changes in interest rates and economic conditions. The CAPM is a distinct, separate model that adds value in addition to the Risk Premium analysis. The differences between these two models are summarized in Figure 18 below.

Figure 18: CAPM vs. Risk Premium Differences

CAPM	Risk Premium
Market risk premium calculated based on the market (S&P 500) return	Equity risk premium calculated by reference to electric utility authorized ROEs
Estimates company-specific market risk through Beta coefficients	Derives an industry-specific cost of equity estimate by using electric utility ROEs
Does not use a statistical relationship to determine the market risk premium	Uses a statistical relationship to determine the equity risk premium
Market risk premium can be more volatile as the expected market return and risk-free rate are more variable	Equity risk premium relationship more stable over time due to the use of more than 1,800 electric rate cases over 46 years and bond yields that are lagged over the average length of a rate case
As illustrated above, the market risk premium estimate is often the most contentious	Fewer contentious inputs, and the inputs (e.g., authorized ROEs and bond yields) are observable and objective.

In response to the second concern, while my Risk Premium analysis is based on authorized ROEs and the corresponding Treasury yields at the time the regulatory decisions were issued (adjusted for the average length of a rate case), investors are informed by

1 allowed ROEs from hundreds of rate case decisions to frame their return expectations. A
2 fundamental principle in setting a just and reasonable return is that the return must be
3 comparable to returns available to investors in companies with commensurate risk. In that
4 regard, the returns that have been authorized for other electric utility companies are highly
5 relevant to investors. Moreover, the use of over 1,800 rate case decisions over the last 46
6 years mitigates the effect of the unique circumstances of any one rate case. Lastly,
7 commissions are tasked with determining the appropriate regulated return that is based on
8 a utility's cost of equity. In my experience, regulators like this Commission carefully
9 weigh the results of various models that reflect investor behavior and use *market data*.
10 From that perspective, authorized ROEs reflect the commission's informed opinion
11 regarding investors' views of the utility's cost of equity, and consequently, the Risk
12 Premium ROE estimates are based on market data and are not circular. Finally, as an
13 example, in a December 2023 report from UBS on the utility sector, the investment bank
14 presents a regression analysis which shows that current authorized ROEs are below what
15 would be expected given the historical level of the 10-year Treasury bond yield – i.e., the
16 premise of my Risk Premium analysis.¹⁵⁴ This demonstrates that investors do use the Risk
17 Premium analysis.

18 In response to the third concern, the 46 years of data that my Risk Premium analysis
19 relies on are used to establish a robust *relationship* between the 30-year Treasury bond
20 yield and the equity risk premium, not directly estimate the ROE. My ROE estimate uses
21 current and projected Treasury bond yields; because of that, it is forward-looking.

¹⁵⁴

UBS, "US Utilities 2024 Outlook: A Year for Resolutions and Resolve," December 12, 2023, at 10.

1
2 **Q. Mr. Rábago cites an article that claims that Federal Energy Regulatory Commission**
3 **(“FERC”) “prohibited” the use of the Risk Premium model.¹⁵⁵ Do you agree with**
4 **this claim?**

5 A. No, I do not. The author of that article, Mark Ellis, both mischaracterizes FERC’s decision
6 and does not cite FERC’s most current stance. In its most recent Order on the ROE topic,
7 FERC noted that, “[t]herefore, while we do not adopt the Risk Premium model here for the
8 reasons discussed above, we do not foreclose the use of a Risk Premium model in future
9 proceedings if parties can demonstrate the concerns discussed above have been
10 addressed.”¹⁵⁶ As such, FERC has not “prohibited” the Risk Premium model; it would
11 consider it if parties can demonstrate that its concerns have been addressed. I addressed
12 FERC’s concerns (i.e., circularity and investor use) above.

13
14 **IX. BUSINESS RISK**

15 **Q. Please summarize the Witnesses’ testimony regarding the business risk of PPL**
16 **Electric and the implications for the Company’s authorized ROE in this proceeding.**

17 A. Mr. Breuning does not conclude that PPL Electric has greater than average business risk
18 due to the Company’s elevated capital expenditure program and regulatory mechanisms,
19 and he disagrees with small size and flotation cost adjustments for PPL Electric.¹⁵⁷ Mr.

¹⁵⁵ EJA St. No. 1, p. 24.

¹⁵⁶ *Ass’n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,036 (Oct. 2024), at P. 24.

¹⁵⁷ I&E St. No. 3, pp. 46-52.

1 Garrett also disputes the need for a small size adjustment for utilities, as well as the need
2 for flotation cost recovery through the authorized ROE.¹⁵⁸ Mr. Cicero argues that PPL
3 Electric's regulatory mechanisms shift "the risk of under recovery of the authorized
4 revenue requirement from the utility to its customers."¹⁵⁹ Finally, Mr. Lyon argues that
5 PPL Electric has lower regulatory lag due to the Company's ability to use a FPFTY in
6 Pennsylvania.¹⁶⁰

7 I will respond to each of these points in this section, starting with the effect of PPL
8 Electric's projected capital expenditures on its risk profile. In addition, it is important to
9 keep in mind that I did not make an explicit adjustment to my ROE recommendation for
10 any of these business risks or flotation costs. Rather, I considered them in developing my
11 ROE recommendation for PPL Electric from within the range of reasonable results. In the
12 end, my ROE recommendation reflects the approximate midpoint of my recommended
13 range.

14
15 **Q. Mr. Breuning challenges the notion that PPL Electric's elevated capital spending**
16 **program supports a higher authorized ROE for the Company.¹⁶¹ What is your**
17 **response?**

18 **A.** As a preliminary matter, Mr. Breuning misinterprets my testimony when he says that "[s]he
19 also claims that PPL Electric requires a higher authorized ROE in order to support these

¹⁵⁸ OCA St. 3, pp. 42-46.

¹⁵⁹ CAUSE-PA St. No. 1, pp. 10-12.

¹⁶⁰ Walmart St. No. 1, pp. 5-6.

¹⁶¹ I&E St. No. 3, pp. 46-47.

1 [capital] expenditures.”¹⁶² I did not claim that PPL Electric requires a “higher authorized
2 ROE” or make an adjustment to my recommended ROE due to PPL Electric’s heightened
3 capital expenditures. That aside, Mr. Breuning asserts that all electric utilities are facing
4 the issues of upgrading or replacing infrastructure, that PPL Electric can file a rate case at
5 any time to address revenue inadequacy, and that the Commission offers risk reducing
6 mechanisms to help reduce regulatory lag in recovery of infrastructure investments or other
7 unforeseen expenditures. As explained below, Mr. Breuning’s position does not compare
8 the Company to its peers on these points.

9 As discussed in my direct testimony, PPL Electric is planning a major capital
10 investment program from 2025-2029 totaling approximately \$4.4 billion of distribution
11 capital expenditures.¹⁶³ PPL Electric updated its capital expenditure plan to total
12 approximately \$4.5 billion of distribution capital expenditures, or \$8.7 billion when also
13 including transmission capital expenditures.¹⁶⁴ The Company will require access to
14 external debt and equity capital to fund its capital program. Credit rating agencies have
15 commented on the Company’s heightened capital program as one of its key credit
16 challenges, as discussed in my direct testimony.¹⁶⁵

17 As can be seen in PPL Electric Exhibit JEN-6R, and in Figure 19 below, PPL
18 Electric’s ratio of projected capital expenditures to net utility plant is 1.15 times higher
19 than the median ratio for the proxy group of 54.96 percent. As such, it is important that

¹⁶² I&E St. No. 3, p. 46 (clarification added).

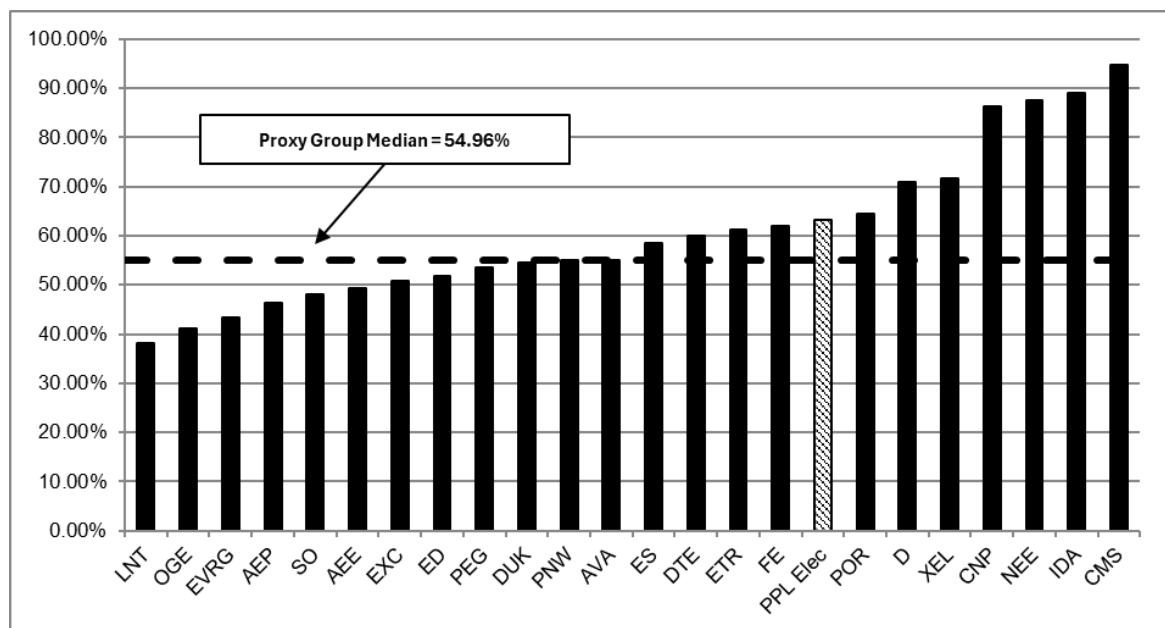
¹⁶³ PPL Electric St. No. 10, p. 38.

¹⁶⁴ PPL Electric Response to the Set II Data Requests of EJA, November 7, 2025, EJA-PPL-II-17
CONFIDENTIAL Attachment 1.

¹⁶⁵ PPL Electric St. No. 10, p. 40.

the authorized ROE for PPL Electric be set at a level that allows the Company to continue to attract both debt and equity under favorable terms under a variety of economic and financial market conditions.

Figure 19: Ratio of 2025-29 Capital Expenditures to 2024 Net Utility Plant¹⁶⁶



Q. Mr. Breuning and Mr. Garrett disagree with your position that PPL Electric's smaller size relative to the proxy group companies is a risk factor that would cause equity investors to require a higher return.¹⁶⁷ What is your response?

A. Mr. Breuning argues against the small size effect, noting that (1) academic literature on small size is not applicable to the utility industry, (2) any size effect on the buying power

¹⁶⁶ PPL Electric Exhibit JEN-6R. Note that I had provided a similar analysis in response to interrogatory question EJA Set II number 17. PPL Electric Exhibit JEN-6R is updated with my rebuttal testimony proxy group and proxy group data through December 31, 2025.

¹⁶⁷ I&E St. No. 3, pp. 47-50; OCA St. 3, pp. 42-44.

1 of the utility is already accounted for through the revenue requirement, and (3) the
2 Commission has previously rejected the application of a size adjustment to the cost of
3 equity calculation.¹⁶⁸ Similarly, Mr. Garrett characterizes the size effect phenomenon first
4 observed by Banz in 1981 as “short lived” and cites several articles that dismiss the small
5 size effect as being outdated.¹⁶⁹ As both witnesses correctly observe, I am not
6 recommending a size adjustment for PPL Electric in this proceeding, and my ROE
7 recommendation does not include an adjustment for size.

8 In response to Mr. Breuning’s testimony regarding academic literature, I cited a
9 2011 article by Chrétien and Coggins in my direct testimony¹⁷⁰ which found that the small
10 size effect was observed for the regulated utility industry specifically. Therefore, I disagree
11 with Mr. Breuning that “[t]he Company has presented no evidence to support application
12 of a non-utility study regarding a size adjustment for risk to a utility setting.”¹⁷¹

13 In response to Mr. Garrett’s contention that the small size effect is outdated, he
14 reaches that conclusion based on references to articles that examine the size effect over a
15 limited number of years.¹⁷² Studies that are based on samples collected over limited
16 timeframes may not capture the higher stock returns achieved by smaller firms over the
17 long-term. Morningstar, which was the original publisher of the size study that is now
18 published by Kroll, explains that investors in small stocks do not always earn returns that

¹⁶⁸ I&E St. No. 3, pp. 47-50.

¹⁶⁹ OCA St. 3, pp. 42-44.

¹⁷⁰ PPL Electric St. No. 10, p. 47.

¹⁷¹ I&E St. No. 3, p. 49.

¹⁷² For example, the Ibbotson article that Mr. Garrett cites on page 43 of his direct testimony reaches conclusions based on only 10 or 20 years.

1 are higher than returns earned from large stocks – and it is precisely why small stocks are
2 riskier, *by definition*.

3 Because investors cannot predict when small-cap returns will be
4 higher than large-cap returns, it has been argued that they do not
5 expect higher rates of return for small stocks. As was illustrated
6 earlier in this chapter, even over periods of many years, investors in
7 small stocks do not always earn returns that are higher than those of
8 investors in large stocks. **By simple definition, one cannot expect**
9 **risky companies to always outperform less risky companies;**
10 **otherwise they would not be risky. Over the long-term,**
11 **however, investors do expect small stocks to outperform large**
12 **stocks.**¹⁷³

13 In the 2023 SBBI Yearbook, Kroll further explains that the risk/return profile must
14 be assessed over long term periods, not short-term periods (emphasis in original).

15 The increased risk faced by investors in small stocks is quite real. It
16 is important to note, however, that the risk/return profile is over the
17 *long-term*. The long-term expected return for any asset class can be
18 quite different from short-term expected returns. Investors in small-
19 cap stocks should expect losses and periods of underperformance
20 relative to large-cap stocks. While this might lead some market
21 observers to speculate that there is no size premium, statistical
22 evidence suggests that periods of smaller stocks' underperformance
23 should be expected. The evidence also suggests that the longer
24 small-cap companies are given to “race” against large-cap
25 companies, the greater the chance that small-cap companies outpace
26 their larger counterparts.¹⁷⁴

27 Kroll goes on to demonstrate that the period over which the size premium is
28 analyzed is a significant factor in whether small-cap stocks outperform large-cap stocks.
29 For example, between 1926-2022, the percentage of periods in which small-cap stocks
30 outperformed large-cap stocks increases as the holding period increases, as shown in Figure

¹⁷³ Morningstar, Inc., 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook, at 112. (emphasis added)

¹⁷⁴ Kroll 2023 SBBI Yearbook, at 147.

20 below. Accordingly, the Commission should not give any weight to Mr. Garret's contention that the small size effect is outdated.

Figure 20: Small-Cap Companies' Performance Minus Large-Cap Companies' Performance (1926-2022)¹⁷⁵

Holding Period	Small Stocks Outperform	Large Stocks Outperform
1 Month	50%	50%
60 Months (5 Years)	54%	46%
120 Months (10 Years)	66%	34%
240 Months (20 Years)	88%	12%
360 Months (30 Years)	96%	4%

Q. Mr. Breuning disputes the 2002 study by Thomas Zepp that you cited in your direct testimony as support for the size premium, claiming that it “does not contain enough credible evidence to refute Dr. Wong’s findings,” since it focuses on a small number of water utility companies and jurisdictions.¹⁷⁶ Have any other commissions or jurisdictions acknowledged the need for a small size premium?

A. Yes, they have. For example, FERC acknowledged the increased risk associated with a company's smaller size and incorporates Kroll's size premia adjustments in the CAPM analysis, which is the same size premia data I presented in PPL Electric Exhibit JEN-7. In its determination in Docket Nos. EL14-12-003 and EL15-45-000, FERC stated that “size premium adjustments improve the accuracy of the CAPM results and cause it to better correspond to the costs of capital estimates employed by investors.”¹⁷⁷ FERC has found

¹⁷⁵ Source: Kroll 2023 SBBI Yearbook, Exhibit 7.3, at 148.

¹⁷⁶ I&E St. No. 3, p. 50.

¹⁷⁷ 169 FERC ¶ 61,129 at 149, paragraph 297.

1 that “sufficient amount of academic literature exists to indicate that many investors rely on
2 the size premia.”¹⁷⁸ Specifically, FERC was not persuaded by the Annie Wong article that
3 Mr. Breuning presents, stating:

4 We also agree with the Presiding Judge that the financial literature
5 arguing against the continued existence of the size premium or its
6 applicability to utilities is unavailing. **Specifically, we do not find**
7 **persuasive the article cited by Professor Annie Wong that**
8 **utilities are less risky than industrial stocks and feature betas**
9 **that do not decrease with firm size.** Even if true, which the MISO
10 TOs aver is not the case, the argument in favor of a size premium
11 adjustment is that there are differences in risk and required returns
12 between small and large companies that are not captured in the
13 betas. Consequently, lack of substantial variance in the betas
14 between large and small companies is not indicative that they feature
15 differences in risk and corresponding returns that are the basis for
16 the size premium adjustment. The subsequent endorsement of this
17 phenomenon, by Dr. Morin, lends credence to the view that
18 Professor Wong’s conclusions are no longer state of the art.
19 Furthermore, an article reconsiders Professor Wong’s evidence and
20 concludes that “new information...indicates that there is a small
21 firm effect in the utility sector.” A more recent article published in
22 *Business Valuation Review* found that “none of the academic papers
23 throughout the last three decades have qualified the [size premium]
24 as a statistical error.” Finally, a 2019 National Association of
25 Certified Valuers and Analysts publication supports the use of the
26 size premium adjustment to the CAPM. We thus find that, based on
27 the evidence of this dynamic and that many investors consider it
28 when evaluating companies, it is appropriate to include it in CAPM
29 determinations.¹⁷⁹

¹⁷⁸ *Id.* at 149, paragraph 299.

¹⁷⁹ *Id.* at 149, paragraph 301 (citations omitted) (emphasis added).

1 **Q. Mr. Breuning and Mr. Garrett contest your position that the authorized ROE for**
2 **PPL Electric should recognize the need for the Company to recover flotation costs.¹⁸⁰**
3 **How do you respond to their arguments on this issue?**

4 A. Mr. Breuning testifies that he is not aware that the Commission has approved a flotation
5 cost adjustment in previous base rate cases, and argues that flotation costs are operating
6 expenses that should be normalized and recovered through rates similar to the treatment of
7 rate case expense, not through an adjustment to the authorized ROE. Mr. Garrett opposes
8 the recovery of flotation costs, arguing that (1) they are not actual “out-of-pocket” costs,
9 (2) the market already accounts for flotation costs, and (3) it is inappropriate to add flotation
10 costs to a proposed ROE that is already “far above the Company’s cost of equity.”

11 As a preliminary matter, I have not recommended an adjustment to the authorized
12 ROE for PPL Electric in this proceeding to account for flotation costs, even though PPL
13 Corporation recently issued 11.3 million shares of common equity through an at-the-
14 market placement.¹⁸¹ Notwithstanding, Mr. Breuning contends that “it is inappropriate to
15 seek an increase to the cost of equity for stock issuance flotation costs,” but offers no
16 explanation as to why it is inappropriate; accordingly the Commission should not give any
17 weight to Mr. Breuning’s unsupported position. Further, flotation costs are costs associated
18 with issuing common equity and are recorded on the balance sheet as paid-in capital; they
19 are not included as operating expenses on the income statement. Therefore, it is

¹⁸⁰ I&E St. No. 3, pp. 50-52; OCA St. 3, pp. 44-46.

¹⁸¹ PPL Electric St. No. 10, p. 51.

1 appropriate to recover flotation costs through an adjustment to the authorized ROE, as
2 explained in my direct testimony.¹⁸²

3 In response to Mr. Garrett's first reason for opposing flotation cost recovery, I
4 disagree that flotation costs are not "out-of-pocket" expenses because the company issuing
5 the common equity is paying fees for preparation, filing, underwriting, and legal services
6 of an investment bank. These are actual and legitimate costs that are deducted from the
7 proceeds that a company such as PPL Corporation receives when the common stock is sold
8 in the market. As explained in my direct testimony, to the extent a company is denied the
9 opportunity to recover prudently incurred flotation costs, actual returns will fall short of
10 expected returns, thereby diminishing the utility's ability to attract capital on reasonable
11 terms.

12 Regarding Mr. Garrett's argument that the market already takes into account
13 flotation costs, this is not true. When a utility issues equity, it does not receive the price of
14 the stock; it receives net proceeds *after* these costs. Consequently, this is not already
15 accounted for in stock prices, as it is borne by the utility, not investors. Even if this were
16 true, then Mr. Garrett is implying that investors would adjust the share price downward
17 because they recognize that the company issuing the stock is receiving less in actual equity
18 proceeds on its balance sheet from the sale of shares. From the perspective of the issuer,
19 in this case PPL Corporation, this suggests that investors would require a higher return
20 because part of that return is being lost to transaction costs associated with the sale of
21 shares. I present an illustrative analysis in PPL Electric Exhibit JEN-13R that demonstrates

¹⁸² PPL Electric St. No. 10, pp. 50-51.

1 how a utility does not earn its authorized ROE without an adjustment for flotation costs.
2 As shown in PPL Electric Exhibit JEN-13R, without flotation cost recovery, retained
3 earnings, book value, earnings per share, and dividends per share are all lower than the
4 scenario in which recovery of flotation costs is allowed in the ROE. The result is that
5 utility perpetually underearns its authorized ROE. This illustrative example provides
6 quantitative support for the point I made in my direct testimony: to the extent that a
7 company is denied the opportunity to recover prudently incurred flotation costs, actual
8 returns will fall short of expected (or required) returns, thereby diminishing the utility's
9 ability to attract adequate capital on reasonable terms.¹⁸³

10 To Mr. Garrett's third point, as a preliminary matter, I disagree with his claim that
11 my recommended ROE is "already far above the Company's cost of equity," as I explain
12 throughout my direct and rebuttal testimonies. I rely on three market-based financial
13 models to estimate PPL Electric's market-based cost of equity. Notwithstanding, the level
14 of PPL Electric's authorized ROE should be based on market data for a risk comparable
15 proxy group of companies that reflects investors' return requirements for that level of risk.
16 The level of the authorized ROE should not determine whether flotation costs, which are a
17 legitimate cost of issuing common equity, are recovered through the authorized ROE.

¹⁸³ PPL Electric St. No. 10, p. 50.

1 **Q. Mr. Breuning, Mr. Cicero, and Mr. Lyon argue that PPL Electric has lower risk due**
2 **to its regulatory mechanisms.¹⁸⁴ Do you agree with these witnesses' positions on this**
3 **issue?**

4 **A.** I agree with Messrs. Breuning, Cicero, and Lyon that regulatory mechanisms, such as the
5 DSIC, FPFTY, and SDER, may mitigate the *absolute* risk of PPL Electric compared to a
6 company that does not have these mechanisms or other regulatory mechanisms that also
7 mitigate risk (e.g., decoupling). However, these witnesses overlook the fact that
8 determining a utility's just and reasonable ROE is a *comparative* exercise; it is necessary
9 to compare the regulatory mechanisms available to PPL Electric to those that are available
10 to the proxy group operating companies. These mechanisms are not unique to
11 Pennsylvania or to PPL Electric, and many proxy group operating companies utilize
12 mechanisms that also mitigate risk that PPL Electric does not use, such as decoupling. As
13 I have demonstrated in PPL Electric Exhibit JEN-7R, like PPL Electric, 52 percent of the
14 operating companies held by the proxy group operate in jurisdictions that use a partially or
15 fully forecast test year, 67 percent have a capital cost recovery mechanism similar to the
16 DSIC, and 29 percent have a storm damage expense recover rider, similar to the SDER.
17 Unlike PPL Electric, 62 percent utilize volumetric risk mitigation mechanisms such as
18 revenue decoupling or weather normalization clauses. I further note that PPL Electric's
19 mechanisms are not new, and investors' return expectations account for the continued
20 implementation of these mechanisms. Because the proxy companies also have similar risk-
21 mitigating mechanisms, any perceived effect on the cost of equity by investors is accounted

¹⁸⁴ I&E St. No. 3, p. 47; CAUSE-PA St. No. 1, pp. 10-13; Walmart St. No. 1, pp. 5-6.

1 for in the market data of the analysis. Therefore, my recommendation accounts for the
2 prevalence of regulatory mechanisms in the proxy group. On that basis, my conclusion is
3 that PPL Electric has comparable regulatory risk to the proxy group companies and that
4 the data used in my various models reflects the regulatory treatment in these other
5 jurisdictions. As such, PPL Electric's authorized ROE should not be lowered due to its
6 regulatory mechanisms.

7
8 **Q. Have your conclusions regarding PPL Electric's business risk changed from those**
9 **you presented in your direct testimony?**

10 A. No, they have not. My research and analyses show PPL Electric has elevated capital
11 spending risk relative to the proxy group, is exposed to greater risk as a result of the
12 Company's smaller relative size, should be allowed to recover flotation costs associated
13 with equity issuances through the authorized ROE, and has regulatory mechanisms similar
14 to those utilized by the proxy group operating companies. Nonetheless, my ROE
15 recommendation does not depend on the Commission finding that PPL Electric has greater
16 business risk than the proxy group. My ROE recommendation is based on the results of
17 the financial models I have used to estimate the cost of equity and does not include an
18 upward adjustment for risk or for flotation costs.

1 **X. UPDATED ROE RESULTS**

2 **Q. Please comment on the importance of using multiple models in determining the cost**
3 **of equity.**

4 A. As explained in my direct testimony,¹⁸⁵ the cost of equity cannot be precisely quantified,
5 thus driving the need to estimate through the use of multiple financial models. Each model
6 holds limiting assumptions and offers a unique perspective on investors' return
7 requirements under varying market conditions. The use of multiple financial models is
8 therefore crucial in providing a robust and comprehensive estimate of the cost of equity for
9 PPL Electric. Accordingly, I encourage the Commission to rely on multiple models, based
10 on sound inputs, to set PPL Electric's authorized ROE, rather than rely on a single model
11 as Mr. Breuning recommends.

12
13 **Q. Have you updated your ROE analyses?**

14 A. Yes, I have updated the results of the financial models used to estimate the cost of equity
15 for PPL Electric in my direct testimony (data as of June 30, 2025) to include market data
16 through December 31, 2025. As previously explained, I updated the proxy group to remove
17 NWE, which brings the updated proxy group to a total of 23 companies. The results of the
18 updated analyses are shown in Figure 21 and PPL Electric Exhibits JEN-1R through JEN-
19 5R.

¹⁸⁵ PPL Electric St. No. 10, p. 4.

Figure 21: Updated ROE Results¹⁸⁶

Model	June 30, 2025	December 31, 2025
DCF	10.29%	10.58%
CAPM	Historical market return: 10.35%	Historical market return: 10.32%
	Forward market return: 12.35%	Forward market return: 13.17%
Risk Premium	10.32%	10.29%
ROE Range	10.30%-12.35%	10.30%-12.35%
ROE Recommendation	11.30%	11.30%

Q. How do these updated results compare with those presented in your direct testimony?

A. The updated data does not meaningfully change the results of the Risk Premium model; results remained at approximately 10.3 percent. The updated data for the DCF led to a 29 basis point increase from 10.29 percent to 10.58 percent, driven by higher analyst EPS growth rates. The updated data for the CAPM produced results ranging from 10.32 percent to 13.17 percent; the CAPM results that used the historical MRP did not meaningfully change, while the CAPM results that used the forward-looking MRP increased by 82 basis points, driven by an increased Value Line-projected market return. The low end of my recommended range of the cost of equity in my direct testimony, 10.30 percent, continues to be supported by the average Risk Premium results and the CAPM and ECAPM results using a long-term average historical market return. The updated CAPM results could

¹⁸⁶ See PPL Electric Exhibit JEN-2 through PPL Electric Exhibit JEN-6 and PPL Electric Exhibit JEN-1R through PPL Electric Exhibit JEN-5R. DCF and CAPM results reflect the average of the proxy group mean and median ROE estimates.

support an increase in the higher end of my recommended range, though I have conservatively not increased the top end of my range. Accordingly, my 11.30 percent ROE recommendation conservatively remains unchanged..

XI. CAPITAL STRUCTURE

Q. Please summarize the Witnesses' recommendations regarding the appropriate capital structure for PPL Electric.

A. Witnesses Breuning, Garrett, Rábago, and Cicero all recommend a hypothetical capital structure for PPL Electric that contains less common equity than the Company's actual and requested capital structure. The Witnesses' recommendations are summarized in Figure 22 below.

Figure 22: Witnesses' Capital Structure Recommendations¹⁸⁷

Witness	Common Equity	Long-term Debt
Nelson ¹⁸⁸	56.05%	43.95%
Breuning	55.00%	45.00%
Garrett	42.00%	58.00%
Rábago	50.00%	50.00%
Cicero	50.00%	50.00%
Lyon	N/A	N/A

¹⁸⁷ I&E St. No. 3, p. 15; OCA St. 3, p. 3; EJA St. No. 1, p. 30; CAUSE-PA St. No. 1, p. 20.

¹⁸⁸ In my direct testimony, on page 61, I noted that the Company was requesting a permanent capital structure consisting of 56.00 percent common equity and 44.00 percent long-term debt. I clarify that the Company is requesting a permanent capital structure consisting of 56.05 percent common equity and 43.95 percent long-term debt.

1 Mr. Breuning looks at the equity ratios of the proxy group *holding companies*,
2 which, by his calculations, contain equity ratios of approximately 30 percent to 50 percent.
3 He then concludes that an equity ratio of 55 percent “helps strike a balance between
4 rewarding the company for carrying more equity while also reducing the costs that would
5 be passed on to ratepayers.”¹⁸⁹ Mr. Garrett similarly examines the ratio of proxy group
6 *holding companies*, from which he calculates an average equity ratio of 42 percent.¹⁹⁰ Mr.
7 Rábago references “current trends in the industry” and PPL Electric Exhibit JEN-9 in
8 recommending his 50 percent equity ratio.¹⁹¹ Mr. Cicero recommends a 50 percent equity
9 ratio, noting that it would save customers \$37.7 million annually and referencing PPL
10 Corporation’s holding company capital structure.¹⁹² Finally, Mr. Lyon does not explicitly
11 address PPL Electric’s capital structure, though uses a 56.05 percent equity ratio in his
12 Exhibit MTL-3, implicitly accepting PPL Electric’s requested permanent capital structure.

13
14 **Q. Both Mr. Breuning and Mr. Garrett reference the proxy group *holding company***
15 **capital structure in their analyses. When setting the authorized permanent capital**
16 **structure, is it correct to analyze the proxy group *holding company* capital structure,**
17 **rather than the proxy group *operating company* capital structure?**

18 **A. No. The comparison of the proxy group holding company capital structures to PPL**
19 **Electric’s capital structure is an apples-to-oranges comparison. The capital structure at the**

¹⁸⁹ I&E St. No. 3, pp. 15-16.

¹⁹⁰ OCA St. 3, p. 51.

¹⁹¹ EJA St. No. 1, p. 30.

¹⁹² CAUSE-PA St. No. 1, pp. 17-20. PPL Electric’s Witness Burgos responds to Mr. Cicero’s PPL Corporation holding company structure argument.

1 consolidated holding company level does not influence the capital structure of the
2 operating subsidiaries. Operating subsidiaries are financed according to the unique risks
3 and financing needs of each subsidiary. Because of the obligation to serve, operating
4 subsidiaries must maintain financial flexibility and access to capital under a variety of
5 operating and capital market environments and constraints. Holding companies, on the
6 other hand, do not have the obligation to serve like regulated operating subsidiaries do.
7 Thus, operating subsidiaries require more equity in the capital structure than their
8 consolidated parent holding companies to maintain financial flexibility necessary to meet
9 the obligation to serve. Further, while I have selected my proxy group to contain
10 companies that primarily have regulated operations, some proxy group holding companies
11 also have unregulated operations (which Mr. Breuning acknowledges¹⁹³); comparing to the
12 proxy group operating company capital structures ensures a comparison to entities that
13 have fully regulated operations.

14 Additionally, the use of the operating company capital structure is supported by
15 long-standing regulatory and financial principles. Under the standalone principle of
16 ratemaking, each utility subsidiary is treated as a “standalone” company.¹⁹⁴ At issue in this
17 proceeding is the appropriate cost of capital for PPL Electric, not the holding company.
18 Under the standalone principle, the allowed return is based on the capital derived from the
19 liabilities/owner’s equity side of the balance sheet used to fund the assets employed in

¹⁹³ As shown in PPL Electric Exhibit JEN-17R [I&E Answer to PPL to I&E-II-2], Mr. Breuning “concedes it is likely that some of the financing contained in the capital structures of each company were used to finance unregulated operations.”

¹⁹⁴ See, e.g., Transcontinental Gas Pipe Line Corp., 80 FERC ¶ 61,157, Opinion No. 414, at 17 (1997).

1 providing utility services. Moreover, according to financial principles,¹⁹⁵ the cost of capital
2 is based on the *use* of funds, not on the *source* of funds. In other words, a company's
3 ownership structure or source of capital does not affect its cost of capital. For example, a
4 company's cost of debt depends on the subject company's risk, not the risk of the investor
5 supplying the debt capital. The same is true for equity capital. From an external investor's
6 perspective, the consolidated parent company must provide a return reflecting the risks of
7 the company's constituent parts. As a result, investors value the consolidated entity on a
8 "sum-of-the-parts" basis, expecting each operating segment to provide its appropriate risk-
9 adjusted return, which is consistent with the standalone regulatory principle. In other
10 words, under both financial and regulatory principles, it is the operating company's risk
11 (*i.e.*, the *use* of capital) that defines the cost of capital, not the holding company or *source*
12 of capital.

13 In summary, comparisons to the consolidated holding company capital structures
14 simply do not reflect the common financing constraints faced by operating subsidiaries
15 with the obligation to serve. The only appropriate apples-to-apples comparison to discern
16 the appropriate capitalization for a regulated operating utility is a comparison to other
17 regulated operating utility subsidiaries.

18 Finally, Mr. Breuning's analysis of Value Line projected capital structures¹⁹⁶
19 suffers this same flaw because Value Line's projected capital structures are also at the

¹⁹⁵ See, *e.g.*, Richard A. Brealey, Steward C. Meyers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 10th Ed., 2011, at 234. "In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is *project risk* that counts."

¹⁹⁶ I&E St. No. 3, pp. 16-17.

1 holding company level, not the operating company level. As such, I recommend that the
2 Commission give no weight to Mr. Breuning's and Mr. Garrett's analyses and
3 recommendations that are based on holding company capital structures.
4

5 **Q. Mr. Breuning, Mr. Rábago, and Mr. Cicero calculate savings to customers based on**
6 **hypothetical capital structures.¹⁹⁷ Do you agree with their calculations?**

7 A. No, I do not. The calculations of Messrs. Breuning, Rábago, and Cicero assume that if
8 PPL Electric's equity ratio were to differ from its requested actual equity ratio, then the
9 cost of debt and cost of equity would stay the same. This is not a sound assumption. As
10 PPL Electric Witness Burgos explains (see PPL Electric St. No. 9-R), while the other
11 parties suggest increasing leverage, they do not account for the cost implications of the
12 additional long-term debt into their proposed hypothetical capital structures. That
13 increased level of debt would weaken PPL Electric's cash flow and debt leverage credit
14 metrics and could potentially cause PPL Electric's credit ratings to be lowered, increasing
15 the cost of debt and equity. Furthermore, having higher levels of debt increases financial
16 risk, which increases the cost of equity, all else equal. As explained by NARUC, "[a]s
17 increasing financial leverage shifts the weight from common equity to lower cost debt, it
18 also increases both the cost of debt and the cost of common equity. In practice, these
19 offsetting impacts cancel each other out over a wide range of capital structure ratios."¹⁹⁸

¹⁹⁷ I&E St. No. 3, pp. 18-19; EJA St. No. 1, pp. 30-31; CAUSE-PA St. No. 1, pp. 16-17.

¹⁹⁸ PPL Electric St. No. 10, pp. 62-63.

1 As such, the Commission should not give any weight to these attempts to quantify the
2 impact of a change in PPL Electric's capital structure.

3
4 **Q. Have other utilities experienced adverse financial implications after a commission**
5 **approved a hypothetical capital structure with significant reductions to the equity**
6 **ratio?**

7 A. Yes, they have. For example, in Case No. 23-894-GA-AIR, East Ohio Gas ("EOG")
8 requested its actual common equity ratio of 61.09 percent,¹⁹⁹ while the Public Utilities
9 Commission of Ohio approved a 51.87 percent hypothetical common equity ratio.²⁰⁰
10 Moody's subsequently downgraded EOG's credit rating one notch and retained a negative
11 outlook, noting that "EOG's downgrade reflects the unfavorable outcome of the rate case
12 which will lead to increased pressure on the company's balance sheet."²⁰¹ Similarly, in
13 Docket No. 22-057-03, Dominion Energy Utah ("DEU") requested its actual common
14 equity ratio of 53.21 percent; however, the Public Service Commission of Utah authorized
15 a hypothetical common equity ratio of 51 percent.²⁰² Afterwards, Moody's downgraded
16 DEU's²⁰³ credit rating one notch, explaining that "[DEU's] Baa1 rating is premised on its

¹⁹⁹ EOG's requested common equity ratio was later revised to 58 percent common equity prior to the evidentiary hearing.

²⁰⁰ *In The Matter of the Application of the East Ohio Gas Company D/B/A Dominion Energy Ohio for Approval to Increase Natural Gas Rates*, Case No. 23-894-GA-AIR, Opinion and Order, June 26, 2025, at 56, 59.

²⁰¹ Moody's Ratings, *Moody's Ratings downgrades East Ohio Gas Company to A3; outlook remains negative*, November 5, 2025, https://www.moodys.com/research/Moodys-Ratings-downgrades-East-Ohio-Gas-Company-to-A3-outlook-Rating-Action--PR_515224.

²⁰² *Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications*, Docket No. 22-057-03, Order, December 23, 2022, at 11, 13. Dominion Energy Utah's authorized equity ratio at the time was 55 percent.

²⁰³ Note that Moody's refers to DEU as Questar Gas Company; Questar Gas Company was rebranded as DEU.

1 51% equity capitalization, which is down from 55% as a result of a December 2022 Utah
2 Public Service Commission (UPSC) rate order. While Moody's does not view the order to
3 be a sign of regulatory contentiousness, it will increase the utility's leverage and reduce
4 key financial metrics."²⁰⁴ As such, if the Commission authorizes a hypothetical capital
5 structure in this case, especially one that is more than 600 basis points (as Mr. Rábago and
6 Mr. Cicero recommend) or 1,400 basis points (as Mr. Garrett recommends) below PPL
7 Electric's actual capital structure, PPL Electric could potentially face a credit rating
8 downgrade.

9
10 **Q. Have you updated your capital structure analysis?**

11 A. Yes, I have. As shown in PPL Electric Exhibit JEN-8R, I updated my capital structure
12 analysis with my updated proxy group and similarly updated the capital structure analysis
13 using Mr. Breuning's proxy group in PPL Electric Exhibit JEN-14R. I also included a five-
14 year average capital structure, similar to what the Commission analyzed when adopting
15 Columbia Gas's requested 54.4 percent equity ratio in Docket No. R-2025-3053499.²⁰⁵
16 Based on this updated analysis, the common equity ratios for the electric utilities within
17 my proxy group range from 44.73 percent to 60.60 percent (three-year average) and from
18 45.07 percent to 60.79 percent (five-year average). For Mr. Breuning's proxy group, his
19 proxy group average ranges from 46.39 percent to 56.72 percent (three-year average) and

²⁰⁴ Moody's Ratings, *Moody's downgrades Questar Gas to Baa1; stable outlook*, February 23, 2024, https://www.moodys.com/research/Moodys-downgrades-Questar-Gas-to-Baa1-stable-outlook-Rating-Action--PR_486058 (clarification added).

²⁰⁵ *Pa. PUC v. Columbia Gas of Pa. Inc.*, Docket No. R-2025-3053499, Opinion and Order, December 4, 2025, at 213.

1 from 45.83 percent to 56.55 percent (five-year average). I note that there are 14 operating
2 companies within my proxy group (and 10 in Mr. Breuning's proxy group) with a five-
3 year average equity ratio above PPL Electric's 56.05 percent requested equity ratio,
4 demonstrating that it is not an outlier. I emphasize that these proxy group equity ratio
5 ranges are correctly based on the equity ratios of the regulated *operating companies*, not
6 the *holding companies*. As such, PPL Electric's proposed 56.05 percent equity ratio is
7 consistent with industry standards, because it is within the range of actual common equity
8 ratios in both my and Mr. Breuning's proxy group.

9 A.

10 **Q. Has the Commission recently accepted a utility's proposed capital structure if it has**
11 **been equal to its proposed actual capital structure and consistent with industry**
12 **standards?**

13 A. Yes, it has. In Columbia Gas's recent base rate case at Docket No. R-2025-3053499, the
14 Commission adopted Columbia Gas's requested 54.4 percent equity ratio,²⁰⁶ rejecting the
15 50 percent equity ratio that OCA and CAUSE-PA recommended in that case.²⁰⁷ In doing
16 so, the Commission noted that "we find that [Columbia Gas]'s projected actual capital
17 structure is within the range of capital structures employed by the companies in the Natural
18 Gas Utility proxy group"²⁰⁸ and "[w]e find it appropriate to reinforce our finding, which
19 we have outlined in several recent base rate proceedings before this Commission, that 'the
20 use of an actual capital structure represents the Company's decision, in which it has full

²⁰⁶ *Id.*

²⁰⁷ *Id.* at 206-208.

²⁰⁸ *Id.* at 212 (clarification added).

1 discretion, on how to capitalize its rate base. This actual capitalization forms the basis upon
2 which the Company attracts capital.”²⁰⁹ This practice aligns with the regulatory guidelines
3 I explain in my direct testimony.²¹⁰
4

5 **Q. Mr. Breuning cites a 2025 average authorized equity ratio of 48.74 percent, while Mr.**
6 **Rábago cites 2023 and first half 2024 average authorized equity ratios of 51.15**
7 **percent and 49.26 percent (respectively).²¹¹ Do you agree with these citations?**

8 A. No, I do not. While I do not dispute that those are the numbers included in the RRA reports,
9 Mr. Breuning and Mr. Rábago ignore the fact that Arkansas, Florida, Indiana, and
10 Michigan rate case outcomes typically report capital structures that contain non-investor
11 supplied sources of capital, such as deferred income tax or customer deposits. I further
12 note that the authorized equity ratios reported by RRA also include short-term debt, which
13 PPL Electric does not include in its ratemaking capital structure. Accordingly, the
14 authorized equity ratios that RRA reports for any rate cases in those states are lower than
15 if they had been calculated only using investor-supplied sources of capital (and without
16 short-term debt), creating an apples-to-oranges comparison to equity ratios in
17 Pennsylvania. To have a meaningful comparison, Arkansas, Florida, Indiana, and
18 Michigan need to be removed prior to calculating the industry average. Doing so yields
19 average authorized equity ratios of 51.59 percent in 2023, 50.75 percent for the first half
20 of 2024, and 49.53 percent in the first 9 months of 2025 for all electric cases (analogous to

²⁰⁹ *Id.* at 210-211.

²¹⁰ PPL Electric St. No. 10, pp. 62-63.

²¹¹ I&E St. No. 3, p. 16; EJA St. No. 1, p. 21.

1 the RRA reports, though it would be more accurate to remove “Limited-Issue Rider” and
2 “Transmission” cases as well, which results in equity ratios of 51.48 percent, 50.32 percent,
3 and 49.33 percent, respectively).²¹² I note, however, that these revised averages still
4 include short-term debt for some companies, making these values conservative compared
5 to PPL Electric’s equity ratio. While these differences are relatively small, it is important
6 for the Commission to understand the nuances that are involved in analyzing authorized
7 equity ratios and drawing appropriate comparisons to other utilities.

8 Lastly, even if these numbers were accurately cited, referencing an industry average
9 authorized equity ratio is not a reasonable methodology to set a utility’s authorized equity
10 ratio. Each utility is different, and the operational and financial aspects that inform a
11 utility’s appropriate capital structure vary from utility to utility. For that reason, it is
12 important to also review the range of authorized equity ratios. For example, the ranges for
13 2023, 2024, and the first 9 months of 2025 had maximum authorized equity ratios of 60.70
14 percent, 56.54 percent, and 57.00 percent, respectively.²¹³ This further demonstrates that
15 PPL Electric’s requested 56.05 percent equity ratio is well within industry standards. The
16 correct methodology is to use the utility’s actual (or projected actual) capital structure if it
17 is reasonable and consistent with industry standards for companies with commensurate
18 risk, as I explained in my direct testimony.²¹⁴

²¹² Source: RRA.

²¹³ *Id.*, removing Limited-Issue Rider and Transmission cases.

²¹⁴ PPL Electric St. No. 10, pp. 62-63.

1 **Q. Referring to “utilities becoming over-leveraged and at risk in volatile risk markets,”**
2 **Mr. Rábago claims that he is “not aware of empirical evidence that such risk really**
3 **exists in financial markets today.”²¹⁵ Does this risk exist in financial markets today?**

4 A. Yes, it does. For example, in its 2026 Industry Outlook, S&P notes that “[t]he industry’s
5 funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to
6 about 13.5%, primarily reflecting rising leverage.”²¹⁶ S&P further notes that:

7 Because about 40% of the IOU industry is actively operating with
8 minimal credit cushion, an unexpected event outside of the base case
9 could result in a negative outlook or even a possible downgrade for
10 many IOU utilities if financial levers are not quickly implemented
11 to restore credit quality. While the industry’s cash flows are highly
12 predictable and stable, unexpected events beyond the base case still
13 occur. Utilities with financial cushion from their downgrade
14 threshold are more able to absorb these unexpected events while
15 maintaining credit quality. However, utilities who strategically
16 operate with minimal financial cushion must have financial levers
17 that they can quickly implement, when necessary, to maintain credit
18 quality.²¹⁷

19 Additionally, Fitch notes that “[m]ost utility parent holding companies have limited
20 headroom in their credit metrics, and several recently announced a reduction in dividend
21 growth rates and equity issuances to support capex funding.”²¹⁸ As such, the utility sector
22 has seen a significant number of credit rating downgrades, and further downgrades are
23 possible if markets become more volatile and utilities do not adequately delever their
24 balance sheets.

²¹⁵ EJA St. No. 1, p. 29.

²¹⁶ S&P Global Ratings, “Industry Credit Outlook 2026 North America Regulated Utilities” January 14, 2026,
at 10.

²¹⁷ *Id.* at 14.

²¹⁸ Fitch Ratings, “Neutral Outlook for North American Utilities in 2025”, December 5, 2024,
<https://www.fitchratings.com/research/corporate-finance/neutral-outlook-for-north-american-utilities-in-2025-05-12-2024>.

1
2 **Q. Mr. Garrett cites capital structures of other industries.²¹⁹ Is this data relevant in this**
3 **proceeding?**

4 A. No, it is not. Non-regulated companies do not have an obligation to serve like regulated
5 utilities do. While companies in other sectors have more flexibility as to when they issue
6 debt or equity, raise or lower prices, change product offerings or even temporarily cease
7 operations based on changing economic and capital market conditions, regulated utilities
8 do not have those options because the obligation to serve compels utilities to provide
9 service to all customers in their footprint without discrimination and to meet customers'
10 energy demands every day regardless of the prevailing economic or capital market
11 environment. As explained in my direct testimony, unlike non-regulated firms, a regulated
12 utility cannot decide to whom it provides utility service in its footprint, how much service
13 it delivers, nor when it provides service;²²⁰ for these reasons, utilities require more financial
14 flexibility than unregulated entities and the ability to access capital in all market
15 environments. Mr. Garrett acknowledges that he is not basing his capital structure
16 recommendation on any industry or company outside of the proxy group;²²¹ the
17 Commission should similarly not give any weight to these non-utility industry capital
18 structures.

²¹⁹ OCA St. 3, pp. 52-54.

²²⁰ PPL Electric St. No. 10, p. 10.

²²¹ *Id.*, p. 54.

1
2 **Q. Has your recommendation related to PPL Electric's capital structure in this**
3 **proceeding changed?**

4 A. No, it has not. I reiterate that the Company's proposed permanent capital structure of 56.05
5 percent common equity and 43.95 percent long-term debt is consistent with sound industry
6 practice and is consequently reasonable and appropriate. In addition, I support PPL
7 Electric Witness Burgos's rebuttal testimony (PPL Electric St. No. 9-R).

8
9 **XII. CONCLUSIONS AND RECOMMENDATIONS**

10 **Q. Please summarize your key conclusions and recommendations.**

11 A. As discussed in my direct and rebuttal testimonies, it is critical that the Company maintain
12 its financial profile in order to provide safe, reliable service to the benefit of customers.
13 With the exception of Mr. Breuning's DCF model results and subsequent ROE
14 recommendation, the Witnesses' analyses and recommendations are unduly low and would
15 not provide a risk-comparable return, impeding PPL Electric's ability to maintain a strong
16 financial profile and attract capital. While Mr. Breuning's recommendation is within my
17 ROE recommendation range, it does not adequately account for the increased cost of
18 capital since PPL Electric's 2012 and 2015 rate cases. Based on the analyses discussed
19 throughout my rebuttal testimony, my 11.30 percent ROE recommendation remains a
20 reasonable and appropriate estimate of PPL Electric's cost of equity. The results of my
21 updated DCF, CAPM, ECAPM, and Risk Premium analyses, along with my analyses of
22 capital market data and the Company's risk profile, continue to support the reasonableness

1 of my 11.30 percent ROE recommendation. Finally, I continue to support the Company's
2 proposed permanent capital structure of 56.05 percent common equity and 43.95 percent
3 long-term debt, as it is consistent with sound industry practice and is consequently
4 reasonable and appropriate.

5
6 **Q. Does this conclude your rebuttal testimony?**

7 **A.** Yes, it does.

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	\$2.03	\$66.22	3.07%	3.17%	7.20%	7.20%	6.00%	6.80%	9.16%	9.97%	10.38%
Ameren Corporation	AEE	\$2.84	\$100.90	2.81%	2.92%	8.50%	7.50%	6.50%	7.50%	9.41%	10.42%	11.43%
American Electric Power Company, Inc.	AEP	\$3.80	\$117.59	3.23%	3.35%	6.50%	8.50%	6.50%	7.17%	9.84%	10.51%	11.87%
Avista Corporation	AVA	\$1.96	\$39.33	4.98%	5.14%	7.10%	6.10%	5.50%	6.23%	10.62%	11.37%	12.26%
CenterPoint Energy, Inc.	CNP	\$0.88	\$38.58	2.28%	2.37%	8.90%	8.75%	7.00%	8.22%	9.36%	10.59%	11.28%
CMS Energy Corporation	CMS	\$2.17	\$71.57	3.03%	3.15%	7.30%	7.50%	8.50%	7.77%	10.44%	10.92%	11.66%
Consolidated Edison, Inc.	ED	\$3.40	\$98.61	3.45%	3.55%	6.10%	6.20%	6.00%	6.10%	9.55%	9.65%	9.75%
Dominion Energy, Inc.	D	\$2.67	\$59.79	4.47%	4.63%	10.30%	6.25%	6.00%	7.52%	10.60%	12.15%	15.00%
DTE Energy Company	DTE	\$4.66	\$131.62	3.54%	3.65%	7.10%	7.38%	4.50%	6.33%	8.12%	9.98%	11.05%
Duke Energy Corporation	DUK	\$4.26	\$118.45	3.60%	3.71%	6.90%	6.80%	6.00%	6.57%	9.70%	10.28%	10.62%
Entergy Corporation	ETR	\$2.56	\$93.56	2.74%	2.85%	10.20%	10.80%	3.00%	8.00%	5.78%	10.85%	13.68%
Eversource Energy	ES	\$3.01	\$67.05	4.49%	4.62%	5.90%	5.92%	5.50%	5.77%	10.11%	10.39%	10.54%
Exelon Corporation	EXC	\$1.60	\$44.46	3.60%	3.71%	6.00%	6.00%	6.00%	6.00%	9.71%	9.71%	9.71%
FirstEnergy Corporation	FE	\$1.78	\$45.36	3.92%	4.05%	6.50%	7.70%	4.50%	6.23%	8.51%	10.28%	11.78%
Evergy, Inc.	EVRG	\$2.78	\$74.25	3.74%	3.87%	5.80%	6.60%	7.50%	6.63%	9.65%	10.50%	11.38%
IDACORP, Inc.	IDA	\$3.52	\$127.30	2.77%	2.86%	8.00%	8.40%	5.00%	7.13%	7.83%	10.00%	11.29%
NextEra Energy, Inc.	NEE	\$2.27	\$82.27	2.75%	2.87%	8.10%	8.08%	8.50%	8.23%	10.94%	11.09%	11.37%
OGE Energy Corporation	OGE	\$1.70	\$43.60	3.90%	4.03%	7.00%	6.50%	6.50%	6.67%	10.53%	10.70%	11.04%
Pinnacle West Capital Corporation	PNW	\$3.64	\$88.51	4.11%	4.21%	2.10%	7.40%	5.00%	4.83%	6.26%	9.05%	11.66%
Portland General Electric Company	POR	\$2.10	\$48.74	4.31%	4.42%	3.40%	5.50%	6.50%	5.13%	7.78%	9.55%	10.95%
Public Service Enterprise Group Inc.	PEG	\$2.52	\$80.65	3.12%	3.24%	8.10%	7.30%	7.00%	7.47%	10.23%	10.71%	11.35%
Southern Company	SO	\$2.96	\$87.38	3.39%	3.51%	7.20%	7.23%	6.50%	6.98%	10.00%	10.48%	10.74%
Xcel Energy Inc.	XEL	\$2.28	\$76.64	2.97%	3.10%	8.90%	8.88%	7.00%	8.26%	10.08%	11.36%	12.01%
Proxy Group Mean				3.49%	3.61%	7.09%	7.33%	6.13%	6.85%	9.31%	10.46%	11.43%
Proxy Group Median				3.45%	3.55%	7.10%	7.30%	6.00%	6.80%	9.70%	10.48%	11.35%
Average of Mean and Median				3.47%	3.58%	7.10%	7.31%	6.07%	6.82%	9.51%	10.47%	11.39%

Notes:

- [1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

Company	Ticker	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	\$2.03	\$66.40	3.06%	3.16%	7.20%	7.20%	6.00%	6.80%	9.15%	9.96%	10.37%
Ameren Corporation	AEE	\$2.84	\$101.92	2.79%	2.89%	8.50%	7.50%	6.50%	7.50%	9.38%	10.39%	11.40%
American Electric Power Company, Inc.	AEP	\$3.80	\$115.55	3.29%	3.41%	6.50%	8.50%	6.50%	7.17%	9.90%	10.57%	11.93%
Avista Corporation	AVA	\$1.96	\$38.35	5.11%	5.27%	7.10%	6.10%	5.50%	6.23%	10.75%	11.50%	12.39%
CenterPoint Energy, Inc.	CNP	\$0.88	\$38.71	2.27%	2.37%	8.90%	8.75%	7.00%	8.22%	9.35%	10.58%	11.27%
CMS Energy Corporation	CMS	\$2.17	\$72.34	3.00%	3.12%	7.30%	7.50%	8.50%	7.77%	10.41%	10.88%	11.63%
Consolidated Edison, Inc.	ED	\$3.40	\$98.87	3.44%	3.54%	6.10%	6.20%	6.00%	6.10%	9.54%	9.64%	9.75%
Dominion Energy, Inc.	D	\$2.67	\$60.11	4.44%	4.61%	10.30%	6.25%	6.00%	7.52%	10.57%	12.13%	14.97%
DTE Energy Company	DTE	\$4.66	\$136.12	3.42%	3.53%	7.10%	7.38%	4.50%	6.33%	8.00%	9.86%	10.93%
Duke Energy Corporation	DUK	\$4.26	\$122.07	3.49%	3.60%	6.90%	6.80%	6.00%	6.57%	9.59%	10.17%	10.51%
Entergy Corporation	ETR	\$2.56	\$93.25	2.75%	2.86%	10.20%	10.80%	3.00%	8.00%	5.79%	10.86%	13.69%
Eversource Energy	ES	\$3.01	\$68.88	4.37%	4.50%	5.90%	5.92%	5.50%	5.77%	9.99%	10.27%	10.42%
Exelon Corporation	EXC	\$1.60	\$45.07	3.55%	3.66%	6.00%	6.00%	6.00%	6.00%	9.66%	9.66%	9.66%
FirstEnergy Corporation	FE	\$1.78	\$45.30	3.93%	4.05%	6.50%	7.70%	4.50%	6.23%	8.52%	10.29%	11.78%
Evergy, Inc.	EVRG	\$2.78	\$74.82	3.72%	3.84%	5.80%	6.60%	7.50%	6.63%	9.62%	10.47%	11.35%
IDACORP, Inc.	IDA	\$3.52	\$129.00	2.73%	2.83%	8.00%	8.40%	5.00%	7.13%	7.80%	9.96%	11.25%
NextEra Energy, Inc.	NEE	\$2.27	\$79.81	2.84%	2.96%	8.10%	8.08%	8.50%	8.23%	11.03%	11.18%	11.46%
OGE Energy Corporation	OGE	\$1.70	\$44.60	3.81%	3.94%	7.00%	6.50%	6.50%	6.67%	10.44%	10.61%	10.94%
Pinnacle West Capital Corporation	PNW	\$3.64	\$89.10	4.09%	4.18%	2.10%	7.40%	5.00%	4.83%	6.23%	9.02%	11.64%
Portland General Electric Company	POR	\$2.10	\$45.92	4.57%	4.69%	3.40%	5.50%	6.50%	5.13%	8.05%	9.82%	11.22%
Public Service Enterprise Group Inc.	PEG	\$2.52	\$81.67	3.09%	3.20%	8.10%	7.30%	7.00%	7.47%	10.19%	10.67%	11.31%
Southern Company	SO	\$2.96	\$91.65	3.23%	3.34%	7.20%	7.23%	6.50%	6.98%	9.83%	10.32%	10.58%
Xcel Energy Inc.	XEL	\$2.28	\$77.38	2.95%	3.07%	8.90%	8.88%	7.00%	8.26%	10.05%	11.33%	11.98%
Proxy Group Mean				3.47%	3.59%	7.09%	7.33%	6.13%	6.85%	9.30%	10.44%	11.41%
Proxy Group Median				3.42%	3.53%	7.10%	7.30%	6.00%	6.80%	9.62%	10.39%	11.31%
Average of Mean and Median				3.45%	3.56%	7.10%	7.31%	6.07%	6.82%	9.46%	10.42%	11.36%

Notes:

- [1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	\$2.03	\$64.42	3.15%	3.26%	7.20%	7.20%	6.00%	6.80%	9.25%	10.06%	10.46%
Ameren Corporation	AEE	\$2.84	\$99.96	2.84%	2.95%	8.50%	7.50%	6.50%	7.50%	9.43%	10.45%	11.46%
American Electric Power Company, Inc.	AEP	\$3.80	\$110.90	3.43%	3.55%	6.50%	8.50%	6.50%	7.17%	10.04%	10.72%	12.07%
Avista Corporation	AVA	\$1.96	\$38.42	5.10%	5.26%	7.10%	6.10%	5.50%	6.23%	10.74%	11.49%	12.38%
CenterPoint Energy, Inc.	CNP	\$0.88	\$38.03	2.31%	2.41%	8.90%	8.75%	7.00%	8.22%	9.39%	10.63%	11.32%
CMS Energy Corporation	CMS	\$2.17	\$71.90	3.02%	3.14%	7.30%	7.50%	8.50%	7.77%	10.43%	10.90%	11.65%
Consolidated Edison, Inc.	ED	\$3.40	\$101.38	3.35%	3.46%	6.10%	6.20%	6.00%	6.10%	9.45%	9.56%	9.66%
Dominion Energy, Inc.	D	\$2.67	\$58.47	4.57%	4.74%	10.30%	6.25%	6.00%	7.52%	10.70%	12.25%	15.10%
DTE Energy Company	DTE	\$4.66	\$135.95	3.43%	3.54%	7.10%	7.38%	4.50%	6.33%	8.00%	9.86%	10.93%
Duke Energy Corporation	DUK	\$4.26	\$120.60	3.53%	3.65%	6.90%	6.80%	6.00%	6.57%	9.64%	10.22%	10.55%
Entergy Corporation	ETR	\$2.56	\$88.89	2.88%	3.00%	10.20%	10.80%	3.00%	8.00%	5.92%	11.00%	13.84%
Eversource Energy	ES	\$3.01	\$66.27	4.54%	4.67%	5.90%	5.92%	5.50%	5.77%	10.17%	10.44%	10.59%
Exelon Corporation	EXC	\$1.60	\$44.65	3.58%	3.69%	6.00%	6.00%	6.00%	6.00%	9.69%	9.69%	9.69%
FirstEnergy Corporation	FE	\$1.78	\$43.50	4.09%	4.22%	6.50%	7.70%	4.50%	6.23%	8.68%	10.45%	11.95%
Evergy, Inc.	EVRG	\$2.78	\$71.75	3.87%	4.00%	5.80%	6.60%	7.50%	6.63%	9.79%	10.64%	11.52%
IDACORP, Inc.	IDA	\$3.52	\$123.72	2.85%	2.95%	8.00%	8.40%	5.00%	7.13%	7.92%	10.08%	11.37%
NextEra Energy, Inc.	NEE	\$2.27	\$75.59	3.00%	3.12%	8.10%	8.08%	8.50%	8.23%	11.20%	11.35%	11.63%
OGE Energy Corporation	OGE	\$1.70	\$44.60	3.81%	3.94%	7.00%	6.50%	6.50%	6.67%	10.44%	10.61%	10.94%
Pinnacle West Capital Corporation	PNW	\$3.64	\$90.24	4.03%	4.13%	2.10%	7.40%	5.00%	4.83%	6.18%	8.96%	11.58%
Portland General Electric Company	POR	\$2.10	\$43.78	4.80%	4.92%	3.40%	5.50%	6.50%	5.13%	8.28%	10.05%	11.45%
Public Service Enterprise Group Inc.	PEG	\$2.52	\$82.11	3.07%	3.18%	8.10%	7.30%	7.00%	7.47%	10.18%	10.65%	11.29%
Southern Company	SO	\$2.96	\$91.61	3.23%	3.34%	7.20%	7.23%	6.50%	6.98%	9.84%	10.32%	10.58%
Xcel Energy Inc.	XEL	\$2.28	\$73.80	3.09%	3.22%	8.90%	8.88%	7.00%	8.26%	10.20%	11.48%	12.13%
Proxy Group Mean				3.55%	3.67%	7.09%	7.33%	6.13%	6.85%	9.37%	10.52%	11.49%
Proxy Group Median				3.43%	3.54%	7.10%	7.30%	6.00%	6.80%	9.69%	10.45%	11.45%
Average of Mean and Median				3.49%	3.60%	7.10%	7.31%	6.07%	6.82%	9.53%	10.48%	11.47%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [8])

[5] Source: Zacks

[6] Source: S&P Capital IQ

[7] Source: Value Line

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	\$0.51	\$0.51	\$0.51	\$0.51	\$0.54	\$0.54	\$0.54	\$0.54	\$66.22	7.20%	7.20%	6.00%	6.80%	9.36%	10.20%	10.61%
Ameren Corporation	AEE	\$0.71	\$0.71	\$0.71	\$0.71	\$0.76	\$0.76	\$0.76	\$0.76	\$100.90	8.50%	7.50%	6.50%	7.50%	9.60%	10.64%	11.68%
American Electric Power Company, Inc.	AEP	\$0.93	\$0.93	\$0.93	\$0.95	\$1.00	\$1.00	\$1.00	\$1.02	\$117.59	6.50%	8.50%	6.50%	7.17%	10.01%	10.71%	12.10%
Avista Corporation	AVA	\$0.49	\$0.49	\$0.49	\$0.49	\$0.52	\$0.52	\$0.52	\$0.52	\$39.33	7.10%	6.10%	5.50%	6.23%	10.97%	11.76%	12.69%
CenterPoint Energy, Inc.	CNP	\$0.22	\$0.22	\$0.22	\$0.22	\$0.24	\$0.24	\$0.24	\$0.24	\$38.58	8.90%	8.75%	7.00%	8.22%	9.53%	10.78%	11.49%
CMS Energy Corporation	CMS	\$0.54	\$0.54	\$0.54	\$0.54	\$0.58	\$0.58	\$0.58	\$0.58	\$71.57	7.30%	7.50%	8.50%	7.77%	10.68%	11.17%	11.93%
Consolidated Edison, Inc.	ED	\$0.85	\$0.85	\$0.85	\$0.85	\$0.90	\$0.90	\$0.90	\$0.90	\$98.61	6.10%	6.20%	6.00%	6.10%	9.79%	9.89%	10.00%
Dominion Energy, Inc.	D	\$0.67	\$0.67	\$0.67	\$0.67	\$0.72	\$0.72	\$0.72	\$0.72	\$59.79	10.30%	6.25%	6.00%	7.52%	10.92%	12.54%	15.50%
DTE Energy Company	DTE	\$1.09	\$1.09	\$1.09	\$1.17	\$1.16	\$1.16	\$1.16	\$1.24	\$131.62	7.10%	7.38%	4.50%	6.33%	8.12%	10.04%	11.14%
Duke Energy Corporation	DUK	\$1.05	\$1.05	\$1.07	\$1.07	\$1.11	\$1.11	\$1.13	\$1.13	\$118.45	6.90%	6.80%	6.00%	6.57%	9.91%	10.51%	10.86%
Entergy Corporation	ETR	\$0.60	\$0.60	\$0.60	\$0.64	\$0.65	\$0.65	\$0.65	\$0.69	\$93.56	10.20%	10.80%	3.00%	8.00%	5.74%	10.93%	13.83%
Eversource Energy	ES	\$0.75	\$0.75	\$0.75	\$0.75	\$0.80	\$0.80	\$0.80	\$0.80	\$67.05	5.90%	5.92%	5.50%	5.77%	10.42%	10.71%	10.86%
Exelon Corporation	EXC	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$0.42	\$0.42	\$0.42	\$44.46	6.00%	6.00%	6.00%	6.00%	9.95%	9.95%	9.95%
FirstEnergy Corporation	FE	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$45.36	6.50%	7.70%	4.50%	6.23%	8.68%	10.51%	12.06%
Evergy, Inc.	EVRG	\$0.67	\$0.67	\$0.67	\$0.70	\$0.71	\$0.71	\$0.71	\$0.74	\$74.25	5.80%	6.60%	7.50%	6.63%	9.78%	10.66%	11.57%
IDACORP, Inc.	IDA	\$0.86	\$0.86	\$0.86	\$0.88	\$0.92	\$0.92	\$0.92	\$0.94	\$127.30	8.00%	8.40%	5.00%	7.13%	7.94%	10.15%	11.47%
NextEra Energy, Inc.	NEE	\$0.57	\$0.57	\$0.57	\$0.57	\$0.61	\$0.61	\$0.61	\$0.61	\$82.27	8.10%	8.08%	8.50%	8.23%	11.18%	11.33%	11.62%
OGE Energy Corporation	OGE	\$0.42	\$0.42	\$0.42	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$43.60	7.00%	6.50%	6.50%	6.67%	10.79%	10.96%	11.32%
Pinnacle West Capital Corporation	PNW	\$0.90	\$0.90	\$0.90	\$0.91	\$0.94	\$0.94	\$0.94	\$0.95	\$88.51	2.10%	7.40%	5.00%	4.83%	6.34%	9.24%	11.95%
Portland General Electric Company	POR	\$0.50	\$0.53	\$0.53	\$0.53	\$0.53	\$0.55	\$0.55	\$0.55	\$48.74	3.40%	5.50%	6.50%	5.13%	7.93%	9.77%	11.22%
Public Service Enterprise Group Inc.	PEG	\$0.63	\$0.63	\$0.63	\$0.63	\$0.68	\$0.68	\$0.68	\$0.68	\$80.65	8.10%	7.30%	7.00%	7.47%	10.47%	10.96%	11.62%
Southern Company	SO	\$0.72	\$0.74	\$0.74	\$0.74	\$0.77	\$0.79	\$0.79	\$0.79	\$87.38	7.20%	7.23%	6.50%	6.98%	10.22%	10.72%	10.99%
Xcel Energy Inc.	XEL	\$0.57	\$0.57	\$0.57	\$0.57	\$0.62	\$0.62	\$0.62	\$0.62	\$76.64	8.90%	8.88%	7.00%	8.26%	10.30%	11.62%	12.29%
Proxy Group Mean											7.09%	7.33%	6.13%	6.85%	9.51%	10.68%	11.69%
Proxy Group Median											7.10%	7.30%	6.00%	6.80%	9.91%	10.71%	11.57%
Average of Mean and Median															9.71%	10.70%	11.63%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ

[3] Source: S&P Capital IQ

[4] Source: S&P Capital IQ

[5] Equals Col. [1] x (1 + Col. [13])

[6] Equals Col. [2] x (1 + Col. [13])

[7] Equals Col. [3] x (1 + Col. [13])

[8] Equals Col. [4] x (1 + Col. [13])

[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[10] Source: Zacks

[11] Source: S&P Capital IQ

[12] Source: Value Line

[13] Equals Average (Cols. [10], [11], [12])

[14] Implied Low DCF

[15] Implied Mean DCF

[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	\$0.51	\$0.51	\$0.51	\$0.51	\$0.54	\$0.54	\$0.54	\$0.54	\$66.40	7.20%	7.20%	6.00%	6.80%	9.35%	10.19%	10.60%
Ameren Corporation	AEE	\$0.71	\$0.71	\$0.71	\$0.71	\$0.76	\$0.76	\$0.76	\$0.76	\$101.92	8.50%	7.50%	6.50%	7.50%	9.57%	10.61%	11.65%
American Electric Power Company, Inc.	AEP	\$0.93	\$0.93	\$0.93	\$0.95	\$1.00	\$1.00	\$1.00	\$1.02	\$115.55	6.50%	8.50%	6.50%	7.17%	10.07%	10.77%	12.17%
Avista Corporation	AVA	\$0.49	\$0.49	\$0.49	\$0.49	\$0.52	\$0.52	\$0.52	\$0.52	\$38.35	7.10%	6.10%	5.50%	6.23%	11.11%	11.90%	12.83%
CenterPoint Energy, Inc.	CNP	\$0.22	\$0.22	\$0.22	\$0.22	\$0.24	\$0.24	\$0.24	\$0.24	\$38.71	8.90%	8.75%	7.00%	8.22%	9.52%	10.77%	11.48%
CMS Energy Corporation	CMS	\$0.54	\$0.54	\$0.54	\$0.54	\$0.58	\$0.58	\$0.58	\$0.58	\$72.34	7.30%	7.50%	8.50%	7.77%	10.64%	11.13%	11.90%
Consolidated Edison, Inc.	ED	\$0.85	\$0.85	\$0.85	\$0.85	\$0.90	\$0.90	\$0.90	\$0.90	\$98.87	6.10%	6.20%	6.00%	6.10%	9.78%	9.88%	9.99%
Dominion Energy, Inc.	D	\$0.67	\$0.67	\$0.67	\$0.67	\$0.72	\$0.72	\$0.72	\$0.72	\$60.11	10.30%	6.25%	6.00%	7.52%	10.90%	12.51%	15.47%
DTE Energy Company	DTE	\$1.09	\$1.09	\$1.09	\$1.17	\$1.16	\$1.16	\$1.16	\$1.24	\$136.12	7.10%	7.38%	4.50%	6.33%	8.00%	9.92%	11.02%
Duke Energy Corporation	DUK	\$1.05	\$1.05	\$1.07	\$1.07	\$1.11	\$1.11	\$1.13	\$1.13	\$122.07	6.90%	6.80%	6.00%	6.57%	9.80%	10.39%	10.74%
Entergy Corporation	ETR	\$0.60	\$0.60	\$0.60	\$0.64	\$0.65	\$0.65	\$0.65	\$0.69	\$93.25	10.20%	10.80%	3.00%	8.00%	5.75%	10.94%	13.84%
Eversource Energy	ES	\$0.75	\$0.75	\$0.75	\$0.75	\$0.80	\$0.80	\$0.80	\$0.80	\$68.88	5.90%	5.92%	5.50%	5.77%	10.28%	10.57%	10.73%
Exelon Corporation	EXC	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$0.42	\$0.42	\$0.42	\$45.07	6.00%	6.00%	6.00%	6.00%	9.90%	9.90%	9.90%
FirstEnergy Corporation	FE	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$45.30	6.50%	7.70%	4.50%	6.23%	8.69%	10.52%	12.07%
Evergy, Inc.	EVRG	\$0.67	\$0.67	\$0.67	\$0.70	\$0.71	\$0.71	\$0.71	\$0.74	\$74.82	5.80%	6.60%	7.50%	6.63%	9.75%	10.63%	11.54%
IDACORP, Inc.	IDA	\$0.86	\$0.86	\$0.86	\$0.88	\$0.92	\$0.92	\$0.92	\$0.94	\$129.00	8.00%	8.40%	5.00%	7.13%	7.90%	10.11%	11.43%
NextEra Energy, Inc.	NEE	\$0.57	\$0.57	\$0.57	\$0.57	\$0.61	\$0.61	\$0.61	\$0.61	\$79.81	8.10%	8.08%	8.50%	8.23%	11.27%	11.43%	11.71%
OGE Energy Corporation	OGE	\$0.42	\$0.42	\$0.42	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$44.60	7.00%	6.50%	6.50%	6.67%	10.69%	10.87%	11.22%
Pinnacle West Capital Corporation	PNW	\$0.90	\$0.90	\$0.90	\$0.91	\$0.94	\$0.94	\$0.94	\$0.95	\$89.10	2.10%	7.40%	5.00%	4.83%	6.32%	9.21%	11.92%
Portland General Electric Company	POR	\$0.50	\$0.53	\$0.53	\$0.53	\$0.53	\$0.55	\$0.55	\$0.55	\$45.92	3.40%	5.50%	6.50%	5.13%	8.21%	10.06%	11.51%
Public Service Enterprise Group Inc.	PEG	\$0.63	\$0.63	\$0.63	\$0.63	\$0.68	\$0.68	\$0.68	\$0.68	\$81.67	8.10%	7.30%	7.00%	7.47%	10.43%	10.92%	11.58%
Southern Company	SO	\$0.72	\$0.74	\$0.74	\$0.74	\$0.77	\$0.79	\$0.79	\$0.79	\$91.65	7.20%	7.23%	6.50%	6.98%	10.04%	10.54%	10.81%
Xcel Energy Inc.	XEL	\$0.57	\$0.57	\$0.57	\$0.57	\$0.62	\$0.62	\$0.62	\$0.62	\$77.38	8.90%	8.88%	7.00%	8.26%	10.27%	11.58%	12.25%
Proxy Group Mean											7.09%	7.33%	6.13%	6.85%	9.49%	10.67%	11.67%
Proxy Group Median											7.10%	7.30%	6.00%	6.80%	9.80%	10.61%	11.54%
Average of Mean and Median															9.64%	10.64%	11.60%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ

[3] Source: S&P Capital IQ

[4] Source: S&P Capital IQ

[5] Equals Col. [1] x (1 + Col. [13])

[6] Equals Col. [2] x (1 + Col. [13])

[7] Equals Col. [3] x (1 + Col. [13])

[8] Equals Col. [4] x (1 + Col. [13])

[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[10] Source: Zacks

[11] Source: S&P Capital IQ

[12] Source: Value Line

[13] Equals Average (Cols. [10], [11], [12])

[14] Implied Low DCF

[15] Implied Mean DCF

[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Alliant Energy Corporation	LNT	\$0.51	\$0.51	\$0.51	\$0.51	\$0.54	\$0.54	\$0.54	\$0.54	\$64.42	7.20%	7.20%	6.00%	6.80%	9.46%	10.29%	10.71%
Ameren Corporation	AEE	\$0.71	\$0.71	\$0.71	\$0.71	\$0.76	\$0.76	\$0.76	\$0.76	\$99.96	8.50%	7.50%	6.50%	7.50%	9.63%	10.67%	11.72%
American Electric Power Company, Inc.	AEP	\$0.93	\$0.93	\$0.93	\$0.95	\$1.00	\$1.00	\$1.00	\$1.02	\$110.90	6.50%	8.50%	6.50%	7.17%	10.23%	10.92%	12.32%
Avista Corporation	AVA	\$0.49	\$0.49	\$0.49	\$0.49	\$0.52	\$0.52	\$0.52	\$0.52	\$38.42	7.10%	6.10%	5.50%	6.23%	11.10%	11.89%	12.82%
CenterPoint Energy, Inc.	CNP	\$0.22	\$0.22	\$0.22	\$0.22	\$0.24	\$0.24	\$0.24	\$0.24	\$38.03	8.90%	8.75%	7.00%	8.22%	9.56%	10.82%	11.53%
CMS Energy Corporation	CMS	\$0.54	\$0.54	\$0.54	\$0.54	\$0.58	\$0.58	\$0.58	\$0.58	\$71.90	7.30%	7.50%	8.50%	7.77%	10.67%	11.15%	11.92%
Consolidated Edison, Inc.	ED	\$0.85	\$0.85	\$0.85	\$0.85	\$0.90	\$0.90	\$0.90	\$0.90	\$101.38	6.10%	6.20%	6.00%	6.10%	9.68%	9.79%	9.89%
Dominion Energy, Inc.	D	\$0.67	\$0.67	\$0.67	\$0.67	\$0.72	\$0.72	\$0.72	\$0.72	\$58.47	10.30%	6.25%	6.00%	7.52%	11.04%	12.65%	15.62%
DTE Energy Company	DTE	\$1.09	\$1.09	\$1.09	\$1.17	\$1.16	\$1.16	\$1.16	\$1.24	\$135.95	7.10%	7.38%	4.50%	6.33%	8.01%	9.92%	11.02%
Duke Energy Corporation	DUK	\$1.05	\$1.05	\$1.07	\$1.07	\$1.11	\$1.11	\$1.13	\$1.13	\$120.60	6.90%	6.80%	6.00%	6.57%	9.84%	10.44%	10.79%
Entergy Corporation	ETR	\$0.60	\$0.60	\$0.60	\$0.64	\$0.65	\$0.65	\$0.65	\$0.69	\$88.89	10.20%	10.80%	3.00%	8.00%	5.89%	11.08%	13.99%
Eversource Energy	ES	\$0.75	\$0.75	\$0.75	\$0.75	\$0.80	\$0.80	\$0.80	\$0.80	\$66.27	5.90%	5.92%	5.50%	5.77%	10.48%	10.77%	10.92%
Exelon Corporation	EXC	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$0.42	\$0.42	\$0.42	\$44.65	6.00%	6.00%	6.00%	6.00%	9.94%	9.94%	9.94%
FirstEnergy Corporation	FE	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$43.50	6.50%	7.70%	4.50%	6.23%	8.86%	10.70%	12.25%
Evergy, Inc.	EVRG	\$0.67	\$0.67	\$0.67	\$0.70	\$0.71	\$0.71	\$0.71	\$0.74	\$71.75	5.80%	6.60%	7.50%	6.63%	9.92%	10.80%	11.71%
IDACORP, Inc.	IDA	\$0.86	\$0.86	\$0.86	\$0.88	\$0.92	\$0.92	\$0.92	\$0.94	\$123.72	8.00%	8.40%	5.00%	7.13%	8.02%	10.24%	11.56%
NextEra Energy, Inc.	NEE	\$0.57	\$0.57	\$0.57	\$0.57	\$0.61	\$0.61	\$0.61	\$0.61	\$75.59	8.10%	8.08%	8.50%	8.23%	11.45%	11.61%	11.89%
OGE Energy Corporation	OGE	\$0.42	\$0.42	\$0.42	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$44.60	7.00%	6.50%	6.50%	6.67%	10.69%	10.87%	11.22%
Pinnacle West Capital Corporation	PNW	\$0.90	\$0.90	\$0.90	\$0.91	\$0.94	\$0.94	\$0.94	\$0.95	\$90.24	2.10%	7.40%	5.00%	4.83%	6.26%	9.15%	11.86%
Portland General Electric Company	POR	\$0.50	\$0.53	\$0.53	\$0.53	\$0.53	\$0.55	\$0.55	\$0.55	\$43.78	3.40%	5.50%	6.50%	5.13%	8.45%	10.30%	11.76%
Public Service Enterprise Group Inc.	PEG	\$0.63	\$0.63	\$0.63	\$0.63	\$0.68	\$0.68	\$0.68	\$0.68	\$82.11	8.10%	7.30%	7.00%	7.47%	10.41%	10.90%	11.56%
Southern Company	SO	\$0.72	\$0.74	\$0.74	\$0.74	\$0.77	\$0.79	\$0.79	\$0.79	\$91.61	7.20%	7.23%	6.50%	6.98%	10.04%	10.54%	10.81%
Xcel Energy Inc.	XEL	\$0.57	\$0.57	\$0.57	\$0.57	\$0.62	\$0.62	\$0.62	\$0.62	\$73.80	8.90%	8.88%	7.00%	8.26%	10.43%	11.75%	12.42%
Proxy Group Mean											7.09%	7.33%	6.13%	6.85%	9.57%	10.75%	11.75%
Proxy Group Median											7.10%	7.30%	6.00%	6.80%	9.92%	10.77%	11.71%
Average of Mean and Median															9.74%	10.76%	11.73%

Notes:

- [1] Source: S&P Capital IQ
- [2] Source: S&P Capital IQ
- [3] Source: S&P Capital IQ
- [4] Source: S&P Capital IQ
- [5] Equals Col. [1] x (1 + Col. [13])
- [6] Equals Col. [2] x (1 + Col. [13])
- [7] Equals Col. [3] x (1 + Col. [13])
- [8] Equals Col. [4] x (1 + Col. [13])
- [9] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025
- [10] Source: Zacks
- [11] Source: S&P Capital IQ
- [12] Source: Value Line
- [13] Equals Average (Cols. [10], [11], [12])
- [14] Implied Low DCF
- [15] Implied Mean DCF
- [16] Implied High DCF

Expected Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	14.70%
[3] Market Cap. Weighted Estimated Required Market Return	15.95%

Notes:

- [1] Source: S&P Capital IQ
[2] Source: Value Line DCF-based expected market return provided in Confidential WP-10
[3] Equals $([1] \times (1 + (0.5 \times [2]))) + [2]$

Expected Market Return
Market DCF Based Method - Bloomberg EPS Growth

[4] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[5] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	17.55%
[6] Market Cap. Weighted Estimated Required Market Return	18.82%

Notes:

- [4] Source: S&P Capital IQ
[5] Source: Bloomberg DCF-based expected market return provided in Confidential WP-11
[6] Equals $([4] \times (1 + (0.5 \times [5]))) + [5]$

Expected Market Return
Market DCF Based Method - S&P Earnings and Estimates

[7] S&P 500 Dividend Yield	1.16%
[8] S&P 500 Growth Rate	17.38%
[9] Estimated Required Market Return	18.64%

Notes:

- [7], [8] Source: S&P Earnings and Estimate Report as of December 31, 2025 See Public WP-1
[9] Equals $([7] \times (1 + (0.5 \times [8]))) + [8]$

Summary of CAPM and ECAPM Results

	Current 30-Year Treasury Yield (4.77%)	Projected 30-Year Treasury Yield (4.62%)
CAPM Forward Market Return	12.80%	12.75%
ECAPM Forward Market Return	13.58%	13.55%
Average Forward Market Return CAPM		13.17%
CAPM Historical Market Return	10.08%	10.04%
ECAPM Historical Market Return	10.60%	10.57%
Average Historical Market Return CAPM		10.32%

Source: Exhibit JEN-4R, pages 2-5

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return and 5-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.77%	0.61	0.80	0.71	15.95%	11.18%	12.67%	13.49%
Ameren Corporation	AEE	4.77%	0.63	0.80	0.71	15.95%	11.18%	12.77%	13.56%
American Electric Power Company, Inc.	AEP	4.77%	0.55	0.70	0.62	15.95%	11.18%	11.73%	12.79%
Avista Corporation	AVA	4.77%	0.53	0.75	0.64	15.95%	11.18%	11.95%	12.95%
CenterPoint Energy, Inc.	CNP	4.77%	0.67	0.80	0.73	15.95%	11.18%	12.99%	13.73%
CMS Energy Corporation	CMS	4.77%	0.57	0.70	0.63	15.95%	11.18%	11.87%	12.89%
Consolidated Edison, Inc.	ED	4.77%	0.47	0.65	0.56	15.95%	11.18%	11.03%	12.26%
Dominion Energy, Inc.	D	4.77%	0.60	0.80	0.70	15.95%	11.18%	12.58%	13.42%
DTE Energy Company	DTE	4.77%	0.60	0.80	0.70	15.95%	11.18%	12.60%	13.44%
Duke Energy Corporation	DUK	4.77%	0.50	0.65	0.58	15.95%	11.18%	11.21%	12.40%
Entergy Corporation	ETR	4.77%	0.66	0.75	0.71	15.95%	11.18%	12.67%	13.49%
Eversource Energy	ES	4.77%	0.63	0.85	0.74	15.95%	11.18%	13.04%	13.77%
Exelon Corporation	EXC	4.77%	0.63	0.75	0.69	15.95%	11.18%	12.47%	13.34%
FirstEnergy Corporation	FE	4.77%	0.57	0.75	0.66	15.95%	11.18%	12.16%	13.11%
Evergy, Inc.	EVRG	4.77%	0.61	0.75	0.68	15.95%	11.18%	12.35%	13.25%
IDACORP, Inc.	IDA	4.77%	0.56	0.65	0.60	15.95%	11.18%	11.53%	12.63%
NextEra Energy, Inc.	NEE	4.77%	0.77	0.90	0.84	15.95%	11.18%	14.13%	14.58%
OGE Energy Corporation	OGE	4.77%	0.67	0.85	0.76	15.95%	11.18%	13.25%	13.93%
Pinnacle West Capital Corporation	PNW	4.77%	0.62	0.75	0.69	15.95%	11.18%	12.43%	13.31%
Portland General Electric Company	POR	4.77%	0.57	0.75	0.66	15.95%	11.18%	12.16%	13.10%
Public Service Enterprise Group Inc.	PEG	4.77%	0.71	0.85	0.78	15.95%	11.18%	13.48%	14.10%
Southern Company	SO	4.77%	0.56	0.65	0.60	15.95%	11.18%	11.51%	12.62%
Xcel Energy Inc.	XEL	4.77%	0.58	0.70	0.64	15.95%	11.18%	11.91%	12.92%

Mean:	12.37%	13.27%
Median:	12.43%	13.31%
Average of the Mean and Median:	12.40%	13.29%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.62%	0.61	0.80	0.71	15.95%	11.34%	12.63%	13.46%
Ameren Corporation	AEE	4.62%	0.63	0.80	0.71	15.95%	11.34%	12.72%	13.53%
American Electric Power Company, Inc.	AEP	4.62%	0.55	0.70	0.62	15.95%	11.34%	11.67%	12.74%
Avista Corporation	AVA	4.62%	0.53	0.75	0.64	15.95%	11.34%	11.90%	12.91%
CenterPoint Energy, Inc.	CNP	4.62%	0.67	0.80	0.73	15.95%	11.34%	12.95%	13.70%
CMS Energy Corporation	CMS	4.62%	0.57	0.70	0.63	15.95%	11.34%	11.81%	12.85%
Consolidated Edison, Inc.	ED	4.62%	0.47	0.65	0.56	15.95%	11.34%	10.96%	12.21%
Dominion Energy, Inc.	D	4.62%	0.60	0.80	0.70	15.95%	11.34%	12.53%	13.39%
DTE Energy Company	DTE	4.62%	0.60	0.80	0.70	15.95%	11.34%	12.55%	13.40%
Duke Energy Corporation	DUK	4.62%	0.50	0.65	0.58	15.95%	11.34%	11.15%	12.35%
Entergy Corporation	ETR	4.62%	0.66	0.75	0.71	15.95%	11.34%	12.63%	13.46%
Eversource Energy	ES	4.62%	0.63	0.85	0.74	15.95%	11.34%	13.00%	13.74%
Exelon Corporation	EXC	4.62%	0.63	0.75	0.69	15.95%	11.34%	12.42%	13.30%
FirstEnergy Corporation	FE	4.62%	0.57	0.75	0.66	15.95%	11.34%	12.11%	13.07%
Evergy, Inc.	EVRG	4.62%	0.61	0.75	0.68	15.95%	11.34%	12.30%	13.21%
IDACORP, Inc.	IDA	4.62%	0.56	0.65	0.60	15.95%	11.34%	11.47%	12.59%
NextEra Energy, Inc.	NEE	4.62%	0.77	0.90	0.84	15.95%	11.34%	14.10%	14.56%
OGE Energy Corporation	OGE	4.62%	0.67	0.85	0.76	15.95%	11.34%	13.21%	13.90%
Pinnacle West Capital Corporation	PNW	4.62%	0.62	0.75	0.69	15.95%	11.34%	12.39%	13.28%
Portland General Electric Company	POR	4.62%	0.57	0.75	0.66	15.95%	11.34%	12.10%	13.06%
Public Service Enterprise Group Inc.	PEG	4.62%	0.71	0.85	0.78	15.95%	11.34%	13.44%	14.07%
Southern Company	SO	4.62%	0.56	0.65	0.60	15.95%	11.34%	11.45%	12.58%
Xcel Energy Inc.	XEL	4.62%	0.58	0.70	0.64	15.95%	11.34%	11.86%	12.88%

Mean:	12.32%	13.23%
Median:	12.39%	13.28%
Average of the Mean and Median:	12.35%	13.25%

Notes:

[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average

[2] Source: Bloomberg Professional Service

[3] Source: Value Line

[4] Equals Average of Col. [2] and Col. [3]

[5] Source: JEN-3R; Value Line DCF-based expected market return

[6] Equals Col. [5] - Col. [1]

[7] Equals Col. [1] + (Col. [4] x Col. [6])

[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])

[9] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14

[10] See Note [2]

[11] See Note [3]

[12] Equals Average of Col. [10] and Col. [11]

[13] See Note [5]

[14] Equals Col. [13] - Col. [9]

[15] Equals Col. [9] + (Col. [12] x Col. [14])

[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return and 10-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.77%	0.75	15.95%	11.18%	13.17%	13.87%
Ameren Corporation	AEE	4.77%	0.72	15.95%	11.18%	12.86%	13.63%
American Electric Power Company, Inc.	AEP	4.77%	0.71	15.95%	11.18%	12.73%	13.53%
Avista Corporation	AVA	4.77%	0.70	15.95%	11.18%	12.65%	13.47%
CenterPoint Energy, Inc.	CNP	4.77%	0.93	15.95%	11.18%	15.15%	15.35%
CMS Energy Corporation	CMS	4.77%	0.71	15.95%	11.18%	12.67%	13.49%
Consolidated Edison, Inc.	ED	4.77%	0.59	15.95%	11.18%	11.36%	12.51%
Dominion Energy, Inc.	D	4.77%	0.68	15.95%	11.18%	12.42%	13.30%
DTE Energy Company	DTE	4.77%	0.78	15.95%	11.18%	13.55%	14.15%
Duke Energy Corporation	DUK	4.77%	0.68	15.95%	11.18%	12.39%	13.28%
Entergy Corporation	ETR	4.77%	0.83	15.95%	11.18%	14.08%	14.55%
Eversource Energy	ES	4.77%	0.79	15.95%	11.18%	13.56%	14.16%
Exelon Corporation	EXC	4.77%	0.81	15.95%	11.18%	13.77%	14.32%
FirstEnergy Corporation	FE	4.77%	0.75	15.95%	11.18%	13.15%	13.85%
Evergy, Inc.	EVRG	4.77%	0.75	15.95%	11.18%	13.14%	13.84%
IDACORP, Inc.	IDA	4.77%	0.74	15.95%	11.18%	13.07%	13.79%
NextEra Energy, Inc.	NEE	4.77%	0.80	15.95%	11.18%	13.70%	14.26%
OGE Energy Corporation	OGE	4.77%	0.87	15.95%	11.18%	14.52%	14.88%
Pinnacle West Capital Corporation	PNW	4.77%	0.79	15.95%	11.18%	13.59%	14.18%
Portland General Electric Company	POR	4.77%	0.74	15.95%	11.18%	13.07%	13.79%
Public Service Enterprise Group Inc.	PEG	4.77%	0.83	15.95%	11.18%	14.05%	14.53%
Southern Company	SO	4.77%	0.74	15.95%	11.18%	13.09%	13.81%
Xcel Energy Inc.	XEL	4.77%	0.72	15.95%	11.18%	12.79%	13.58%

Mean:	13.24%	13.92%
Median:	13.14%	13.84%
Average of the Mean and Median:	13.19%	13.88%

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.62%	0.75	15.95%	11.34%	13.13%	13.84%
Ameren Corporation	AEE	4.62%	0.72	15.95%	11.34%	12.81%	13.60%
American Electric Power Company, Inc.	AEP	4.62%	0.71	15.95%	11.34%	12.68%	13.50%
Avista Corporation	AVA	4.62%	0.70	15.95%	11.34%	12.60%	13.44%
CenterPoint Energy, Inc.	CNP	4.62%	0.93	15.95%	11.34%	15.13%	15.34%
CMS Energy Corporation	CMS	4.62%	0.71	15.95%	11.34%	12.62%	13.46%
Consolidated Edison, Inc.	ED	4.62%	0.59	15.95%	11.34%	11.29%	12.46%
Dominion Energy, Inc.	D	4.62%	0.68	15.95%	11.34%	12.37%	13.26%
DTE Energy Company	DTE	4.62%	0.78	15.95%	11.34%	13.51%	14.12%
Duke Energy Corporation	DUK	4.62%	0.68	15.95%	11.34%	12.34%	13.24%
Entergy Corporation	ETR	4.62%	0.83	15.95%	11.34%	14.05%	14.53%
Eversource Energy	ES	4.62%	0.79	15.95%	11.34%	13.53%	14.14%
Exelon Corporation	EXC	4.62%	0.81	15.95%	11.34%	13.74%	14.30%
FirstEnergy Corporation	FE	4.62%	0.75	15.95%	11.34%	13.11%	13.82%
Evergy, Inc.	EVRG	4.62%	0.75	15.95%	11.34%	13.10%	13.81%
IDACORP, Inc.	IDA	4.62%	0.74	15.95%	11.34%	13.03%	13.76%
NextEra Energy, Inc.	NEE	4.62%	0.80	15.95%	11.34%	13.66%	14.24%
OGE Energy Corporation	OGE	4.62%	0.87	15.95%	11.34%	14.50%	14.86%
Pinnacle West Capital Corporation	PNW	4.62%	0.79	15.95%	11.34%	13.55%	14.15%
Portland General Electric Company	POR	4.62%	0.74	15.95%	11.34%	13.03%	13.76%
Public Service Enterprise Group Inc.	PEG	4.62%	0.83	15.95%	11.34%	14.02%	14.51%
Southern Company	SO	4.62%	0.74	15.95%	11.34%	13.05%	13.78%
Xcel Energy Inc.	XEL	4.62%	0.72	15.95%	11.34%	12.75%	13.55%

Mean:	13.20%	13.89%
Median:	13.10%	13.81%
Average of the Mean and Median:	13.15%	13.85%

Notes:

- [1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: JEN-3R; Value Line DCF-based expected market return
[4] Equals Col. [3] - Col. [1]
[5] Equals Col. [1] + (Col. [2] x Col. [4])
[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[7] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[8] See Note [2]
[9] See Note [3]
[10] Equals Col. [9] - Col. [7]
[11] Equals Col. [7] + (Col. [8] x Col. [10])
[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 5-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30- Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.77%	0.61	0.80	0.71	12.17%	7.40%	10.00%	10.54%
Ameren Corporation	AEE	4.77%	0.63	0.80	0.71	12.17%	7.40%	10.06%	10.59%
American Electric Power Company, Inc.	AEP	4.77%	0.55	0.70	0.62	12.17%	7.40%	9.38%	10.08%
Avista Corporation	AVA	4.77%	0.53	0.75	0.64	12.17%	7.40%	9.52%	10.18%
CenterPoint Energy, Inc.	CNP	4.77%	0.67	0.80	0.73	12.17%	7.40%	10.21%	10.70%
CMS Energy Corporation	CMS	4.77%	0.57	0.70	0.63	12.17%	7.40%	9.47%	10.14%
Consolidated Edison, Inc.	ED	4.77%	0.47	0.65	0.56	12.17%	7.40%	8.91%	9.73%
Dominion Energy, Inc.	D	4.77%	0.60	0.80	0.70	12.17%	7.40%	9.94%	10.50%
DTE Energy Company	DTE	4.77%	0.60	0.80	0.70	12.17%	7.40%	9.95%	10.51%
Duke Energy Corporation	DUK	4.77%	0.50	0.65	0.58	12.17%	7.40%	9.03%	9.82%
Entergy Corporation	ETR	4.77%	0.66	0.75	0.71	12.17%	7.40%	10.00%	10.54%
Eversource Energy	ES	4.77%	0.63	0.85	0.74	12.17%	7.40%	10.24%	10.73%
Exelon Corporation	EXC	4.77%	0.63	0.75	0.69	12.17%	7.40%	9.87%	10.44%
FirstEnergy Corporation	FE	4.77%	0.57	0.75	0.66	12.17%	7.40%	9.66%	10.29%
Eergy, Inc.	EVRG	4.77%	0.61	0.75	0.68	12.17%	7.40%	9.79%	10.38%
IDACORP, Inc.	IDA	4.77%	0.56	0.65	0.60	12.17%	7.40%	9.24%	9.97%
NextEra Energy, Inc.	NEE	4.77%	0.77	0.90	0.84	12.17%	7.40%	10.96%	11.26%
OGE Energy Corporation	OGE	4.77%	0.67	0.85	0.76	12.17%	7.40%	10.38%	10.83%
Pinnacle West Capital Corporation	PNW	4.77%	0.62	0.75	0.69	12.17%	7.40%	9.84%	10.42%
Portland General Electric Company	POR	4.77%	0.57	0.75	0.66	12.17%	7.40%	9.66%	10.29%
Public Service Enterprise Group Inc.	PEG	4.77%	0.71	0.85	0.78	12.17%	7.40%	10.53%	10.94%
Southern Company	SO	4.77%	0.56	0.65	0.60	12.17%	7.40%	9.23%	9.97%
Xcel Energy Inc.	XEL	4.77%	0.58	0.70	0.64	12.17%	7.40%	9.50%	10.17%

Mean:	9.80%	10.39%
Median:	9.84%	10.42%
Average of the Mean and Median:	9.82%	10.41%

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30- Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.62%	0.61	0.80	0.71	12.17%	7.55%	9.95%	10.51%
Ameren Corporation	AEE	4.62%	0.63	0.80	0.71	12.17%	7.55%	10.02%	10.55%
American Electric Power Company, Inc.	AEP	4.62%	0.55	0.70	0.62	12.17%	7.55%	9.32%	10.03%
Avista Corporation	AVA	4.62%	0.53	0.75	0.64	12.17%	7.55%	9.47%	10.14%
CenterPoint Energy, Inc.	CNP	4.62%	0.67	0.80	0.73	12.17%	7.55%	10.17%	10.67%
CMS Energy Corporation	CMS	4.62%	0.57	0.70	0.63	12.17%	7.55%	9.41%	10.10%
Consolidated Edison, Inc.	ED	4.62%	0.47	0.65	0.56	12.17%	7.55%	8.84%	9.67%
Dominion Energy, Inc.	D	4.62%	0.60	0.80	0.70	12.17%	7.55%	9.89%	10.46%
DTE Energy Company	DTE	4.62%	0.60	0.80	0.70	12.17%	7.55%	9.90%	10.47%
Duke Energy Corporation	DUK	4.62%	0.50	0.65	0.58	12.17%	7.55%	8.97%	9.77%
Entergy Corporation	ETR	4.62%	0.66	0.75	0.71	12.17%	7.55%	9.95%	10.51%
Eversource Energy	ES	4.62%	0.63	0.85	0.74	12.17%	7.55%	10.20%	10.70%
Exelon Corporation	EXC	4.62%	0.63	0.75	0.69	12.17%	7.55%	9.82%	10.40%
FirstEnergy Corporation	FE	4.62%	0.57	0.75	0.66	12.17%	7.55%	9.61%	10.25%
Eergy, Inc.	EVRG	4.62%	0.61	0.75	0.68	12.17%	7.55%	9.74%	10.34%
IDACORP, Inc.	IDA	4.62%	0.56	0.65	0.60	12.17%	7.55%	9.18%	9.93%
NextEra Energy, Inc.	NEE	4.62%	0.77	0.90	0.84	12.17%	7.55%	10.94%	11.24%
OGE Energy Corporation	OGE	4.62%	0.67	0.85	0.76	12.17%	7.55%	10.35%	10.80%
Pinnacle West Capital Corporation	PNW	4.62%	0.62	0.75	0.69	12.17%	7.55%	9.79%	10.39%
Portland General Electric Company	POR	4.62%	0.57	0.75	0.66	12.17%	7.55%	9.60%	10.25%
Public Service Enterprise Group Inc.	PEG	4.62%	0.71	0.85	0.78	12.17%	7.55%	10.50%	10.92%
Southern Company	SO	4.62%	0.56	0.65	0.60	12.17%	7.55%	9.17%	9.92%
Xcel Energy Inc.	XEL	4.62%	0.58	0.70	0.64	12.17%	7.55%	9.44%	10.12%

Mean:	9.75%	10.35%
Median:	9.79%	10.39%
Average of the Mean and Median:	9.77%	10.37%

Notes:

[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average

[2] Source: Bloomberg Professional Service

[3] Source: Value Line

[4] Equals Average of Col. [2] and Col. [3]

[5] Kroll Cost of Capital Navigator

[6] Equals Col. [5] - Col. [1]

[7] Equals Col. [1] + (Col. [4] x Col. [6])

[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])

[9] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14

[10] See Note [2]

[11] See Note [3]

[12] Equals Average of Col. [10] and Col. [11]

[13] See Note [5]

[14] Equals Col. [13] - Col. [9]

[15] Equals Col. [9] + (Col. [12] x Col. [14])

[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 10-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.77%	0.75	12.17%	7.40%	10.33%	10.79%
Ameren Corporation	AEE	4.77%	0.72	12.17%	7.40%	10.12%	10.63%
American Electric Power Company, Inc.	AEP	4.77%	0.71	12.17%	7.40%	10.04%	10.57%
Avista Corporation	AVA	4.77%	0.70	12.17%	7.40%	9.98%	10.53%
CenterPoint Energy, Inc.	CNP	4.77%	0.93	12.17%	7.40%	11.64%	11.77%
CMS Energy Corporation	CMS	4.77%	0.71	12.17%	7.40%	10.00%	10.54%
Consolidated Edison, Inc.	ED	4.77%	0.59	12.17%	7.40%	9.13%	9.89%
Dominion Energy, Inc.	D	4.77%	0.68	12.17%	7.40%	9.83%	10.42%
DTE Energy Company	DTE	4.77%	0.78	12.17%	7.40%	10.58%	10.98%
Duke Energy Corporation	DUK	4.77%	0.68	12.17%	7.40%	9.81%	10.40%
Entergy Corporation	ETR	4.77%	0.83	12.17%	7.40%	10.93%	11.24%
Eversource Energy	ES	4.77%	0.79	12.17%	7.40%	10.59%	10.98%
Exelon Corporation	EXC	4.77%	0.81	12.17%	7.40%	10.73%	11.09%
FirstEnergy Corporation	FE	4.77%	0.75	12.17%	7.40%	10.31%	10.78%
Evergy, Inc.	EVRG	4.77%	0.75	12.17%	7.40%	10.31%	10.77%
IDACORP, Inc.	IDA	4.77%	0.74	12.17%	7.40%	10.26%	10.74%
NextEra Energy, Inc.	NEE	4.77%	0.80	12.17%	7.40%	10.68%	11.05%
OGE Energy Corporation	OGE	4.77%	0.87	12.17%	7.40%	11.22%	11.46%
Pinnacle West Capital Corporation	PNW	4.77%	0.79	12.17%	7.40%	10.60%	11.00%
Portland General Electric Company	POR	4.77%	0.74	12.17%	7.40%	10.26%	10.74%
Public Service Enterprise Group Inc.	PEG	4.77%	0.83	12.17%	7.40%	10.91%	11.23%
Southern Company	SO	4.77%	0.74	12.17%	7.40%	10.28%	10.75%
Xcel Energy Inc.	XEL	4.77%	0.72	12.17%	7.40%	10.08%	10.60%
						Mean:	10.37%
						Median:	10.31%
						Average of the Mean and Median:	10.34%
							10.80%

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Alliant Energy Corporation	LNT	4.62%	0.75	12.17%	7.55%	10.29%	10.76%
Ameren Corporation	AEE	4.62%	0.72	12.17%	7.55%	10.08%	10.60%
American Electric Power Company, Inc.	AEP	4.62%	0.71	12.17%	7.55%	9.99%	10.54%
Avista Corporation	AVA	4.62%	0.70	12.17%	7.55%	9.94%	10.49%
CenterPoint Energy, Inc.	CNP	4.62%	0.93	12.17%	7.55%	11.62%	11.76%
CMS Energy Corporation	CMS	4.62%	0.71	12.17%	7.55%	9.95%	10.51%
Consolidated Edison, Inc.	ED	4.62%	0.59	12.17%	7.55%	9.07%	9.84%
Dominion Energy, Inc.	D	4.62%	0.68	12.17%	7.55%	9.78%	10.38%
DTE Energy Company	DTE	4.62%	0.78	12.17%	7.55%	10.54%	10.95%
Duke Energy Corporation	DUK	4.62%	0.68	12.17%	7.55%	9.76%	10.36%
Entergy Corporation	ETR	4.62%	0.83	12.17%	7.55%	10.91%	11.22%
Eversource Energy	ES	4.62%	0.79	12.17%	7.55%	10.56%	10.96%
Exelon Corporation	EXC	4.62%	0.81	12.17%	7.55%	10.70%	11.07%
FirstEnergy Corporation	FE	4.62%	0.75	12.17%	7.55%	10.27%	10.75%
Evergy, Inc.	EVRG	4.62%	0.75	12.17%	7.55%	10.27%	10.74%
IDACORP, Inc.	IDA	4.62%	0.74	12.17%	7.55%	10.22%	10.71%
NextEra Energy, Inc.	NEE	4.62%	0.80	12.17%	7.55%	10.65%	11.03%
OGE Energy Corporation	OGE	4.62%	0.87	12.17%	7.55%	11.20%	11.44%
Pinnacle West Capital Corporation	PNW	4.62%	0.79	12.17%	7.55%	10.57%	10.97%
Portland General Electric Company	POR	4.62%	0.74	12.17%	7.55%	10.22%	10.71%
Public Service Enterprise Group Inc.	PEG	4.62%	0.83	12.17%	7.55%	10.89%	11.21%
Southern Company	SO	4.62%	0.74	12.17%	7.55%	10.24%	10.72%
Xcel Energy Inc.	XEL	4.62%	0.72	12.17%	7.55%	10.03%	10.57%
						Mean:	10.34%
						Median:	10.27%
						Average of the Mean and Median:	10.30%
							10.77%

Notes:

[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average

[2] Source: Bloomberg Professional Service

[3] Kroll Cost of Capital Navigator

[4] Equals Col. [3] - Col. [1]

[5] Equals Col. [1] + (Col. [2] x Col. [4])

[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])

[7] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14

[8] See Note [2]

[9] See Note [3]

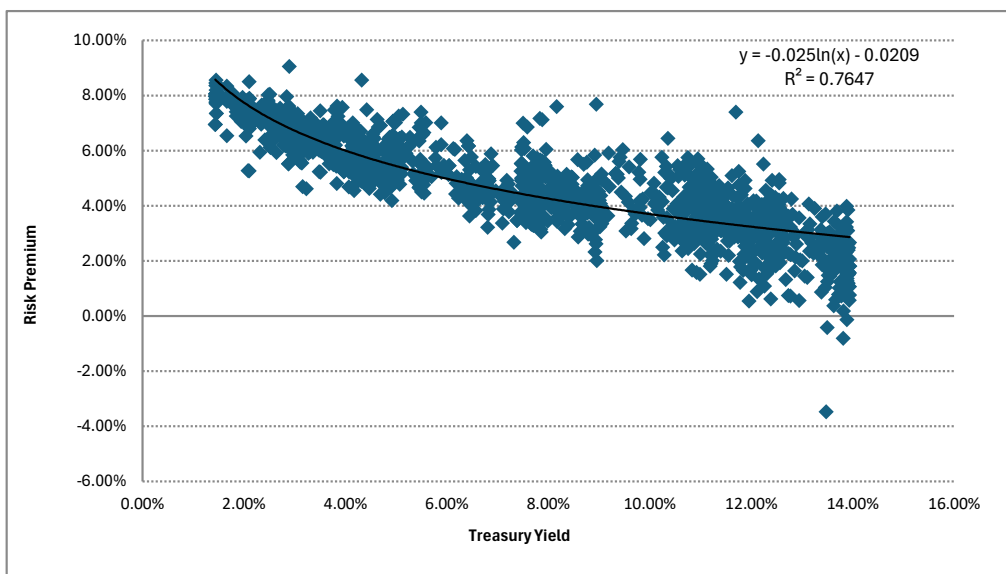
[10] Equals Col. [9] - Col. [7]

[11] Equals Col. [7] + (Col. [8] x Col. [10])

[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.09%	-2.51%			
		Current 30-Year Treasury	4.77%	5.56%
		Projected 30-Year Treasury	4.62%	5.64%
				10.33%
				10.26%



Notes:

[1] Constant of regression equation

[2] Slope of regression equation

[3] Sources: Current = Federal Reserve Bank of St. Louis (FRED),

Projected = Average of near-term and long-term projected 30-year Treasury yield from

Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14

[4] Equals [1] + $\ln([3]) \times [2]$

[5] Equals [3] + [4]

[6] Source: S&P Capital IQ

[7] Source: S&P Capital IQ

[8] Source: Bloomberg Professional, equals 202-trading day average (i.e. lag period)

[9] Equals [7] - [8]

Bond Yield Plus Risk Premium			
[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.38%	5.01%
1/9/1980	15.00%	9.39%	5.61%
1/14/1980	15.17%	9.41%	5.76%
1/17/1980	13.93%	9.43%	4.50%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.63%	3.17%
2/14/1980	13.00%	9.64%	3.36%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.89%	2.81%
3/14/1980	13.50%	9.96%	3.54%
3/26/1980	14.16%	10.09%	4.07%
3/27/1980	14.24%	10.11%	4.13%
3/28/1980	14.50%	10.13%	4.37%
4/10/1980	12.75%	10.25%	2.50%
4/13/1980	13.85%	10.27%	3.58%
4/15/1980	15.50%	10.29%	5.21%
4/21/1980	13.90%	10.33%	3.57%
4/21/1980	13.25%	10.33%	2.92%
4/23/1980	16.80%	10.36%	6.44%
4/29/1980	15.50%	10.40%	5.10%
5/6/1980	13.70%	10.44%	3.26%
5/7/1980	15.00%	10.45%	4.55%
5/8/1980	13.75%	10.45%	3.30%
5/9/1980	14.35%	10.46%	3.89%
5/13/1980	13.60%	10.47%	3.13%
5/15/1980	13.25%	10.49%	2.76%
5/19/1980	13.75%	10.50%	3.25%
5/27/1980	14.60%	10.53%	4.07%
5/27/1980	13.62%	10.53%	3.09%
5/29/1980	16.00%	10.55%	5.45%
5/30/1980	13.80%	10.56%	3.24%
6/2/1980	15.63%	10.56%	5.07%
6/9/1980	15.90%	10.59%	5.31%
6/10/1980	13.78%	10.59%	3.19%
6/12/1980	14.25%	10.60%	3.65%
6/19/1980	13.40%	10.61%	2.79%
6/30/1980	13.00%	10.64%	2.36%
6/30/1980	13.40%	10.64%	2.76%
7/9/1980	14.75%	10.67%	4.08%
7/10/1980	15.00%	10.67%	4.33%
7/15/1980	15.80%	10.69%	5.11%
7/18/1980	13.80%	10.70%	3.10%
7/22/1980	14.10%	10.71%	3.39%
7/24/1980	15.00%	10.72%	4.28%
7/25/1980	13.48%	10.73%	2.75%
7/31/1980	14.58%	10.75%	3.83%
8/8/1980	14.00%	10.77%	3.23%
8/8/1980	13.50%	10.77%	2.73%
8/8/1980	15.45%	10.77%	4.68%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.83%	1.67%
9/15/1980	15.80%	10.87%	4.93%
9/15/1980	13.93%	10.87%	3.06%
9/15/1980	13.50%	10.87%	2.63%
9/24/1980	12.50%	10.92%	1.58%
9/24/1980	15.00%	10.92%	4.08%
9/26/1980	13.75%	10.94%	2.81%
9/30/1980	14.20%	10.96%	3.24%
9/30/1980	14.10%	10.96%	3.14%
10/1/1980	13.90%	10.96%	2.94%
10/3/1980	15.50%	10.98%	4.52%
10/7/1980	12.50%	10.99%	1.51%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	14.50%	11.00%	3.50%
10/9/1980	13.25%	11.00%	2.25%
10/16/1980	16.10%	11.02%	5.08%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	14.25%	11.10%	3.15%
10/31/1980	13.75%	11.10%	2.65%
11/4/1980	15.00%	11.11%	3.89%
11/5/1980	14.00%	11.12%	2.88%
11/5/1980	13.75%	11.12%	2.63%
11/8/1980	13.75%	11.14%	2.61%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.21%	2.79%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	15.10%	11.23%	3.87%
12/8/1980	14.15%	11.23%	2.92%
12/9/1980	15.35%	11.23%	4.12%
12/12/1980	15.45%	11.23%	4.22%
12/17/1980	13.25%	11.24%	2.01%
12/18/1980	15.80%	11.24%	4.56%
12/19/1980	14.50%	11.24%	3.26%
12/19/1980	14.64%	11.24%	3.40%
12/22/1980	13.45%	11.24%	2.21%
12/22/1980	15.00%	11.24%	3.76%
12/30/1980	14.50%	11.22%	3.28%
12/30/1980	14.95%	11.22%	3.73%
12/31/1980	13.39%	11.22%	2.17%
1/2/1981	15.25%	11.22%	4.03%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.20%	4.05%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%
1/26/1981	15.25%	11.21%	4.04%
1/27/1981	15.00%	11.21%	3.79%
1/31/1981	13.47%	11.22%	2.25%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.24%	4.51%
2/11/1981	15.60%	11.28%	4.32%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/20/1981	15.25%	11.33%	3.92%
3/11/1981	15.40%	11.49%	3.91%
3/12/1981	14.51%	11.50%	3.01%
3/12/1981	16.00%	11.50%	4.50%
3/13/1981	13.02%	11.51%	1.51%
3/18/1981	16.19%	11.54%	4.65%
3/19/1981	13.75%	11.55%	2.20%
3/23/1981	14.30%	11.57%	2.73%
3/25/1981	15.30%	11.60%	3.70%
4/1/1981	14.53%	11.67%	2.86%
4/3/1981	19.10%	11.70%	7.40%
4/8/1981	15.00%	11.75%	3.25%
4/8/1981	15.30%	11.75%	3.55%
4/8/1981	17.00%	11.75%	5.25%
4/8/1981	16.50%	11.75%	4.75%
4/9/1981	13.75%	11.77%	1.98%
4/12/1981	13.57%	11.79%	1.78%
4/14/1981	15.30%	11.82%	3.48%
4/15/1981	13.50%	11.84%	1.66%
4/16/1981	14.10%	11.86%	2.24%
4/20/1981	16.80%	11.88%	4.92%
4/20/1981	14.00%	11.88%	2.12%
4/23/1981	16.00%	11.92%	4.08%
4/27/1981	13.61%	11.96%	1.65%
4/27/1981	12.50%	11.96%	0.54%
4/29/1981	13.65%	11.99%	1.66%
4/30/1981	13.50%	12.01%	1.49%
5/4/1981	16.22%	12.04%	4.18%
5/5/1981	14.40%	12.06%	2.34%
5/7/1981	16.25%	12.10%	4.15%
5/7/1981	16.27%	12.10%	4.17%
5/8/1981	13.00%	12.12%	0.88%
5/8/1981	16.00%	12.12%	3.88%
5/12/1981	13.50%	12.15%	1.35%
5/15/1981	15.75%	12.21%	3.54%
5/18/1981	14.88%	12.22%	2.66%
5/20/1981	16.00%	12.25%	3.75%
5/21/1981	14.00%	12.27%	1.73%
5/26/1981	14.90%	12.29%	2.61%
5/27/1981	15.00%	12.31%	2.69%
5/29/1981	15.50%	12.33%	3.17%
6/1/1981	16.50%	12.34%	4.16%
6/3/1981	14.67%	12.36%	2.31%
6/5/1981	13.00%	12.38%	0.62%
6/10/1981	16.75%	12.41%	4.34%
6/17/1981	14.40%	12.45%	1.95%
6/18/1981	16.33%	12.46%	3.87%
6/25/1981	14.75%	12.51%	2.24%
6/26/1981	16.00%	12.52%	3.48%
6/30/1981	15.25%	12.54%	2.71%
7/1/1981	15.50%	12.55%	2.95%
7/1/1981	17.50%	12.55%	4.95%
7/10/1981	16.00%	12.61%	3.39%
7/14/1981	16.90%	12.63%	4.27%
7/15/1981	16.00%	12.64%	3.36%
7/17/1981	15.00%	12.66%	2.34%
7/20/1981	15.00%	12.67%	2.33%
7/21/1981	14.00%	12.68%	1.32%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/28/1981	13.48%	12.73%	0.75%
7/31/1981	13.50%	12.77%	0.73%
7/31/1981	16.00%	12.77%	3.23%
7/31/1981	15.00%	12.77%	2.23%
8/5/1981	15.71%	12.82%	2.89%
8/10/1981	14.50%	12.86%	1.64%
8/11/1981	15.00%	12.87%	2.13%
8/20/1981	16.50%	12.94%	3.56%
8/20/1981	13.50%	12.94%	0.56%
8/24/1981	15.00%	12.96%	2.04%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.05%	1.45%
9/10/1981	14.50%	13.10%	1.40%
9/11/1981	16.00%	13.11%	2.89%
9/16/1981	16.00%	13.14%	2.86%
9/17/1981	16.50%	13.15%	3.35%
9/23/1981	15.85%	13.19%	2.66%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.32%	2.43%
10/15/1981	16.25%	13.36%	2.89%
10/16/1981	16.50%	13.37%	3.13%
10/16/1981	15.50%	13.37%	2.13%
10/19/1981	14.25%	13.38%	0.87%
10/20/1981	15.25%	13.40%	1.85%
10/20/1981	17.00%	13.40%	3.60%
10/23/1981	16.00%	13.44%	2.56%
10/27/1981	10.00%	13.48%	-3.48%
10/29/1981	16.50%	13.50%	3.00%
10/29/1981	14.75%	13.50%	1.25%
11/3/1981	15.17%	13.53%	1.64%
11/5/1981	16.60%	13.55%	3.05%
11/6/1981	15.17%	13.55%	1.62%
11/24/1981	15.50%	13.60%	1.90%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	16.10%	13.60%	2.50%
11/25/1981	15.25%	13.60%	1.65%
11/25/1981	15.35%	13.60%	1.75%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.00%	13.61%	2.39%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.62%	2.63%
12/14/1981	14.00%	13.62%	0.38%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.63%	2.87%
12/18/1981	15.45%	13.63%	1.82%
12/30/1981	16.00%	13.66%	2.34%
12/30/1981	16.25%	13.66%	2.59%
12/30/1981	14.25%	13.66%	0.59%
12/31/1981	16.15%	13.67%	2.48%
1/4/1982	15.50%	13.67%	1.83%
1/11/1982	14.50%	13.72%	0.78%
1/11/1982	17.00%	13.72%	3.28%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.74%	2.01%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/15/1982	15.00%	13.75%	1.25%
1/15/1982	16.50%	13.75%	2.75%
1/22/1982	16.25%	13.79%	2.46%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.81%	-0.81%
1/29/1982	15.50%	13.81%	1.69%
2/1/1982	15.85%	13.82%	2.03%
2/3/1982	16.44%	13.83%	2.61%
2/8/1982	15.50%	13.85%	1.65%
2/11/1982	16.00%	13.87%	2.13%
2/11/1982	16.20%	13.87%	2.33%
2/17/1982	15.00%	13.88%	1.12%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.88%	1.22%
3/27/1982	15.40%	13.89%	1.51%
3/30/1982	15.50%	13.90%	1.60%
3/31/1982	17.00%	13.90%	3.10%
4/1/1982	16.50%	13.91%	2.59%
4/1/1982	14.70%	13.91%	0.79%
4/2/1982	15.50%	13.91%	1.59%
4/4/1982	15.50%	13.91%	1.59%
4/7/1982	16.40%	13.92%	2.48%
4/12/1982	14.50%	13.93%	0.57%
4/22/1982	15.75%	13.94%	1.81%
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	15.50%	13.94%	1.56%
4/30/1982	14.70%	13.94%	0.76%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.91%	0.78%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/20/1982	15.00%	13.91%	1.09%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.88%	0.97%
6/18/1982	15.50%	13.87%	1.63%
6/21/1982	14.90%	13.87%	1.03%
6/23/1982	16.00%	13.87%	2.13%
6/23/1982	16.17%	13.87%	2.30%
6/24/1982	14.85%	13.86%	0.99%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/25/1982	14.70%	13.86%	0.84%
7/1/1982	16.00%	13.85%	2.15%
7/2/1982	15.62%	13.84%	1.78%
7/2/1982	17.00%	13.84%	3.16%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.82%	1.94%
7/14/1982	16.02%	13.82%	2.20%
7/19/1982	16.50%	13.80%	2.70%
7/22/1982	17.00%	13.78%	3.22%
7/22/1982	14.50%	13.78%	0.72%
7/27/1982	16.75%	13.75%	3.00%
7/29/1982	16.50%	13.74%	2.76%
8/11/1982	17.50%	13.69%	3.81%
8/18/1982	17.07%	13.64%	3.43%
8/20/1982	15.73%	13.61%	2.12%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.50%	-0.42%
9/15/1982	16.25%	13.50%	2.75%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.49%	1.76%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.46%	1.04%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.25%	2.50%
10/22/1982	17.15%	13.25%	3.90%
10/29/1982	15.54%	13.17%	2.37%
11/1/1982	15.50%	13.15%	2.35%
11/3/1982	17.20%	13.13%	4.07%
11/4/1982	16.25%	13.12%	3.13%
11/5/1982	16.20%	13.10%	3.10%
11/9/1982	16.00%	13.06%	2.94%
11/23/1982	15.85%	12.89%	2.96%
11/23/1982	15.50%	12.89%	2.61%
11/30/1982	16.50%	12.82%	3.68%
12/1/1982	17.04%	12.79%	4.25%
12/6/1982	15.00%	12.74%	2.26%
12/6/1982	16.35%	12.74%	3.61%
12/10/1982	15.50%	12.67%	2.83%
12/13/1982	16.00%	12.65%	3.35%
12/14/1982	16.40%	12.63%	3.77%
12/14/1982	15.30%	12.63%	2.67%
12/20/1982	16.00%	12.58%	3.42%
12/21/1982	15.85%	12.56%	3.29%
12/21/1982	14.75%	12.56%	2.19%
12/22/1982	16.75%	12.55%	4.20%
12/22/1982	16.58%	12.55%	4.03%
12/22/1982	16.25%	12.55%	3.70%
12/29/1982	14.90%	12.49%	2.41%
12/29/1982	16.25%	12.49%	3.76%
12/30/1982	16.35%	12.47%	3.88%
12/30/1982	16.00%	12.47%	3.53%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/30/1982	16.77%	12.47%	4.30%
1/5/1983	17.33%	12.41%	4.92%
1/11/1983	15.90%	12.35%	3.55%
1/12/1983	15.50%	12.34%	3.16%
1/12/1983	14.63%	12.34%	2.29%
1/20/1983	17.75%	12.24%	5.51%
1/21/1983	15.00%	12.23%	2.77%
1/24/1983	14.50%	12.21%	2.29%
1/24/1983	15.50%	12.21%	3.29%
1/25/1983	15.85%	12.20%	3.65%
1/27/1983	16.14%	12.17%	3.97%
2/1/1983	18.50%	12.14%	6.36%
2/4/1983	14.00%	12.10%	1.90%
2/10/1983	15.00%	12.06%	2.94%
2/21/1983	15.50%	11.99%	3.51%
2/22/1983	15.50%	11.98%	3.52%
2/23/1983	15.10%	11.96%	3.14%
2/23/1983	16.00%	11.96%	4.04%
3/2/1983	15.25%	11.90%	3.35%
3/9/1983	15.20%	11.83%	3.37%
3/15/1983	13.00%	11.78%	1.22%
3/18/1983	15.25%	11.74%	3.51%
3/23/1983	15.40%	11.70%	3.70%
3/24/1983	15.00%	11.68%	3.32%
3/29/1983	15.50%	11.64%	3.86%
3/30/1983	16.71%	11.62%	5.09%
3/31/1983	15.00%	11.61%	3.39%
4/3/1983	15.20%	11.61%	3.59%
4/7/1983	15.50%	11.54%	3.96%
4/10/1983	14.81%	11.52%	3.29%
4/18/1983	14.50%	11.41%	3.09%
4/19/1983	16.00%	11.39%	4.61%
4/29/1983	16.00%	11.26%	4.74%
5/1/1983	14.50%	11.26%	3.24%
5/9/1983	15.50%	11.16%	4.34%
5/11/1983	16.46%	11.13%	5.33%
5/12/1983	14.14%	11.12%	3.02%
5/18/1983	15.00%	11.06%	3.94%
5/23/1983	14.90%	11.02%	3.88%
5/23/1983	15.50%	11.02%	4.48%
5/25/1983	15.50%	11.00%	4.50%
5/27/1983	15.00%	10.97%	4.03%
5/31/1983	15.50%	10.96%	4.54%
5/31/1983	14.00%	10.96%	3.04%
6/2/1983	14.50%	10.94%	3.56%
6/17/1983	15.03%	10.85%	4.18%
7/1/1983	14.80%	10.78%	4.02%
7/1/1983	14.90%	10.78%	4.12%
7/8/1983	16.25%	10.76%	5.49%
7/13/1983	13.20%	10.76%	2.44%
7/19/1983	15.10%	10.75%	4.35%
7/19/1983	15.00%	10.75%	4.25%
7/25/1983	16.25%	10.74%	5.51%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.50%	10.75%	5.75%
8/3/1983	16.34%	10.75%	5.59%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	16.40%	10.80%	5.60%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/22/1983	15.50%	10.80%	4.70%
8/31/1983	14.75%	10.84%	3.91%
9/7/1983	15.00%	10.86%	4.14%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.94%	4.56%
9/30/1983	16.15%	10.95%	5.20%
9/30/1983	15.25%	10.95%	4.30%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.98%	4.54%
10/17/1983	15.50%	10.99%	4.51%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.00%	5.50%
10/19/1983	16.25%	11.00%	5.25%
10/26/1983	15.00%	11.03%	3.97%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.15%	3.92%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.17%	3.33%
12/15/1983	15.56%	11.19%	4.37%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.21%	4.79%
12/20/1983	14.69%	11.21%	3.48%
12/20/1983	16.25%	11.21%	5.04%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.26%	3.49%
1/10/1984	15.90%	11.29%	4.61%
1/12/1984	15.60%	11.30%	4.30%
1/18/1984	13.75%	11.32%	2.43%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.36%	4.74%
1/31/1984	15.25%	11.37%	3.88%
2/1/1984	14.80%	11.38%	3.42%
2/6/1984	14.75%	11.40%	3.35%
2/6/1984	13.75%	11.40%	2.35%
2/9/1984	15.25%	11.42%	3.83%
2/15/1984	15.70%	11.44%	4.26%
2/20/1984	15.00%	11.45%	3.55%
2/20/1984	15.00%	11.45%	3.55%
2/22/1984	14.75%	11.47%	3.28%
2/28/1984	14.50%	11.50%	3.00%
3/2/1984	14.25%	11.53%	2.72%
3/20/1984	16.00%	11.64%	4.36%
3/23/1984	15.50%	11.66%	3.84%
3/26/1984	14.71%	11.67%	3.04%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/1/1984	15.50%	11.70%	3.80%
4/5/1984	14.74%	11.74%	3.00%
4/10/1984	15.72%	11.76%	3.96%
4/16/1984	15.00%	11.80%	3.20%
4/17/1984	16.20%	11.80%	4.40%
4/24/1984	14.64%	11.84%	2.80%
4/30/1984	14.40%	11.87%	2.53%
5/16/1984	14.69%	11.98%	2.71%
5/16/1984	15.00%	11.98%	3.02%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.15%	3.10%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.25%	3.00%
7/2/1984	13.35%	12.26%	1.09%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.32%	4.18%
7/13/1984	16.25%	12.33%	3.92%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.35%	3.15%
7/18/1984	15.30%	12.35%	2.95%
7/19/1984	14.30%	12.36%	1.94%
7/24/1984	16.79%	12.39%	4.40%
7/31/1984	16.00%	12.42%	3.58%
8/3/1984	14.25%	12.44%	1.81%
8/17/1984	14.30%	12.48%	1.82%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.50%	3.80%
8/31/1984	15.55%	12.52%	3.03%
9/6/1984	16.00%	12.53%	3.47%
9/10/1984	14.75%	12.54%	2.21%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.55%	4.83%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	16.25%	12.57%	3.68%
9/28/1984	15.00%	12.57%	2.43%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.58%	3.02%
10/22/1984	15.00%	12.58%	2.42%
10/26/1984	16.40%	12.58%	3.82%
10/31/1984	16.25%	12.58%	3.67%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.58%	3.17%
11/20/1984	15.25%	12.57%	2.68%
11/20/1984	15.92%	12.57%	3.35%
11/23/1984	15.00%	12.57%	2.43%
11/28/1984	16.15%	12.56%	3.59%
12/3/1984	15.80%	12.56%	3.24%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.53%	3.87%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.52%	3.48%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.36%	2.11%
3/1/1985	13.84%	12.31%	1.53%
3/8/1985	16.85%	12.29%	4.56%
3/14/1985	15.50%	12.26%	3.24%
3/15/1985	15.62%	12.26%	3.36%
3/29/1985	15.62%	12.17%	3.45%
4/3/1985	14.60%	12.14%	2.46%
4/8/1985	15.50%	12.12%	3.38%
4/15/1985	15.70%	12.07%	3.63%
4/21/1985	14.00%	12.03%	1.97%
4/25/1985	15.50%	12.00%	3.50%
4/29/1985	15.00%	11.98%	3.02%
5/2/1985	14.68%	11.94%	2.74%
5/8/1985	15.62%	11.90%	3.72%
5/10/1985	16.50%	11.88%	4.62%
5/29/1985	14.61%	11.74%	2.87%
5/31/1985	16.00%	11.72%	4.28%
6/14/1985	15.50%	11.61%	3.89%
7/9/1985	15.00%	11.45%	3.55%
7/16/1985	14.50%	11.40%	3.10%
7/26/1985	14.50%	11.33%	3.17%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.27%	3.73%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.15%	3.35%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.09%	3.81%
9/23/1985	15.00%	11.07%	3.93%
9/27/1985	15.50%	11.05%	4.45%
9/27/1985	15.80%	11.05%	4.75%
10/2/1985	14.75%	11.04%	3.71%
10/2/1985	14.00%	11.04%	2.96%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.85%	10.96%	4.89%
10/24/1985	15.82%	10.96%	4.86%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.95%	5.70%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.92%	3.58%
11/7/1985	15.50%	10.90%	4.60%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.70%	4.30%
12/20/1985	15.00%	10.68%	4.32%
12/20/1985	14.50%	10.68%	3.82%
12/20/1985	14.50%	10.68%	3.82%
1/24/1986	15.40%	10.41%	4.99%
1/31/1986	15.00%	10.36%	4.64%
2/5/1986	15.00%	10.33%	4.67%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/5/1986	15.75%	10.33%	5.42%
2/10/1986	13.30%	10.30%	3.00%
2/11/1986	12.50%	10.28%	2.22%
2/14/1986	14.40%	10.25%	4.15%
2/18/1986	16.00%	10.24%	5.76%
2/24/1986	14.50%	10.18%	4.32%
2/26/1986	14.00%	10.16%	3.84%
3/5/1986	14.90%	10.08%	4.82%
3/11/1986	14.50%	10.02%	4.48%
3/12/1986	13.50%	10.01%	3.49%
3/27/1986	14.10%	9.86%	4.24%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.83%	4.17%
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/13/1986	13.40%	9.71%	3.69%
4/22/1986	15.00%	9.59%	5.41%
5/16/1986	14.50%	9.33%	5.17%
5/16/1986	14.50%	9.33%	5.17%
5/29/1986	13.90%	9.20%	4.70%
5/30/1986	15.10%	9.19%	5.91%
6/2/1986	12.81%	9.17%	3.64%
6/11/1986	14.00%	9.08%	4.92%
6/24/1986	16.63%	8.94%	7.69%
6/26/1986	12.00%	8.91%	3.09%
6/26/1986	14.75%	8.91%	5.84%
6/30/1986	13.00%	8.88%	4.12%
7/10/1986	14.34%	8.76%	5.58%
7/11/1986	12.75%	8.74%	4.01%
7/14/1986	12.60%	8.72%	3.88%
7/17/1986	12.40%	8.67%	3.73%
7/25/1986	14.25%	8.58%	5.67%
8/6/1986	13.50%	8.45%	5.05%
8/14/1986	13.50%	8.36%	5.14%
9/16/1986	12.75%	8.07%	4.68%
9/19/1986	13.25%	8.04%	5.21%
10/1/1986	14.00%	7.96%	6.04%
10/3/1986	13.40%	7.94%	5.46%
10/31/1986	13.50%	7.78%	5.72%
11/5/1986	13.00%	7.76%	5.24%
12/3/1986	12.90%	7.59%	5.31%
12/4/1986	14.44%	7.58%	6.86%
12/16/1986	13.60%	7.53%	6.07%
12/22/1986	13.80%	7.51%	6.29%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.49%	5.51%
1/12/1987	12.40%	7.47%	4.93%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.47%	5.53%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.83%	7.17%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.86%	5.04%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.94%	5.04%
8/26/1987	12.63%	8.05%	4.58%
8/26/1987	12.75%	8.05%	4.70%
8/27/1987	13.25%	8.06%	5.19%
9/9/1987	13.00%	8.13%	4.87%
9/30/1987	13.00%	8.30%	4.70%
9/30/1987	12.75%	8.30%	4.45%
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.43%	4.57%
11/2/1987	13.00%	8.54%	4.46%
11/19/1987	13.00%	8.63%	4.37%
11/30/1987	12.00%	8.68%	3.32%
12/3/1987	14.20%	8.70%	5.50%
12/15/1987	13.25%	8.77%	4.48%
12/16/1987	13.72%	8.78%	4.94%
12/16/1987	13.50%	8.78%	4.72%
12/17/1987	11.75%	8.78%	2.97%
12/18/1987	13.50%	8.79%	4.71%
12/21/1987	12.01%	8.80%	3.21%
12/22/1987	12.75%	8.81%	3.94%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	12.00%	8.81%	3.19%
12/22/1987	13.00%	8.81%	4.19%
1/20/1988	13.80%	8.93%	4.87%
1/26/1988	13.90%	8.95%	4.95%
1/29/1988	13.20%	8.95%	4.25%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.95%	2.01%
5/3/1988	12.91%	8.97%	3.94%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	9.00%	3.75%
7/1/1988	12.75%	9.00%	3.75%
7/20/1988	13.40%	8.97%	4.43%
8/5/1988	12.75%	8.92%	3.83%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.01%	3.99%
12/20/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.03%	4.37%
1/27/1989	13.00%	9.05%	3.95%
1/31/1989	13.00%	9.05%	3.95%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.01%	4.19%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.92%	4.33%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.49%	4.51%
12/15/1989	13.00%	8.34%	4.66%
12/20/1989	12.90%	8.32%	4.58%
12/21/1989	12.90%	8.32%	4.58%
12/27/1989	13.00%	8.30%	4.70%
12/27/1989	12.50%	8.30%	4.20%
1/10/1990	12.80%	8.25%	4.55%
1/11/1990	12.90%	8.24%	4.66%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.20%	3.80%
2/9/1990	12.10%	8.18%	3.92%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.31%	4.89%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.33%	4.17%
7/6/1990	12.35%	8.34%	4.01%
7/6/1990	12.10%	8.34%	3.76%
8/10/1990	12.55%	8.40%	4.15%
8/16/1990	13.21%	8.42%	4.79%
8/22/1990	13.10%	8.44%	4.66%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.62%	4.22%
10/19/1990	13.00%	8.66%	4.34%
10/25/1990	12.30%	8.67%	3.63%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.65%	4.45%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.64%	4.11%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.61%	3.89%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.58%	4.42%
2/14/1991	12.72%	8.57%	4.15%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.52%	4.48%
3/8/1991	12.30%	8.52%	3.78%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.44%	4.31%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.39%	3.31%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.38%	3.62%
7/3/1991	12.50%	8.37%	4.13%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	12.50%	8.18%	4.32%
11/26/1991	11.60%	8.18%	3.42%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/27/1992	12.65%	8.06%	4.59%
1/31/1992	12.00%	8.05%	3.95%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.99%	3.44%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.94%	3.51%
4/10/1992	11.50%	7.94%	3.56%
4/14/1992	11.50%	7.93%	3.57%
5/5/1992	11.50%	7.90%	3.60%
5/12/1992	12.46%	7.89%	4.57%
5/12/1992	11.87%	7.89%	3.98%
6/1/1992	12.30%	7.87%	4.43%
6/12/1992	10.90%	7.86%	3.04%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	13.50%	7.84%	5.66%
7/13/1992	11.90%	7.84%	4.06%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.70%	4.05%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.70%	5.46%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.30%	7.65%	4.65%
12/22/1992	12.40%	7.65%	4.75%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.63%	4.27%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.25%	4.50%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.23%	4.27%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.96%	4.54%
9/21/1993	10.50%	6.81%	3.69%
9/29/1993	11.47%	6.77%	4.70%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.61%	4.19%
11/12/1993	12.00%	6.57%	5.43%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.45%	3.62%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.36%	4.89%
2/25/1994	12.00%	6.36%	5.64%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.35%	4.65%
4/25/1994	11.00%	6.41%	4.59%
5/10/1994	11.75%	6.45%	5.30%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.53%	4.47%
6/27/1994	11.40%	6.64%	4.76%
8/5/1994	12.75%	6.87%	5.88%
10/31/1994	10.00%	7.32%	2.68%
11/9/1994	10.85%	7.38%	3.47%
11/9/1994	10.85%	7.38%	3.47%
11/18/1994	11.20%	7.45%	3.75%
11/22/1994	11.60%	7.46%	4.14%
11/28/1994	11.06%	7.49%	3.57%
12/8/1994	11.70%	7.54%	4.16%
12/8/1994	11.50%	7.54%	3.96%
12/14/1994	10.95%	7.56%	3.39%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.57%	3.93%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.68%	3.32%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.71%	3.79%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.71%	3.39%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.52%	3.58%
9/11/1995	11.30%	7.21%	4.09%
9/27/1995	11.50%	7.13%	4.37%
9/27/1995	11.75%	7.13%	4.62%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/27/1995	11.30%	7.13%	4.17%
9/29/1995	11.00%	7.12%	3.88%
11/9/1995	12.36%	6.90%	5.46%
11/9/1995	11.38%	6.90%	4.48%
11/17/1995	11.00%	6.86%	4.14%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.75%	4.65%
12/20/1995	11.60%	6.70%	4.90%
12/27/1995	12.00%	6.67%	5.33%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.44%	4.81%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.44%	4.81%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.70%	4.30%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.80%	4.20%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.83%	4.92%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.61%	4.39%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.40%	6.35%
3/2/1998	11.25%	6.29%	4.96%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.23%	4.27%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.55%	6.65%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.39%	4.91%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.51%	5.24%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.89%	5.21%
1/7/2000	11.50%	6.04%	5.46%
1/7/2000	11.50%	6.04%	5.46%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.19%	5.06%
5/24/2000	11.00%	6.18%	4.82%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.47%	5.53%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.05%	7.25%
3/6/2003	10.75%	5.03%	5.72%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.99%	7.01%
4/3/2003	12.00%	4.96%	7.04%
4/15/2003	11.15%	4.94%	6.21%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.80%	4.70%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.93%	4.92%
12/17/2003	10.70%	4.93%	5.77%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.98%	5.77%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/25/2004	10.25%	5.08%	5.17%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.06%	5.44%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.06%	5.91%
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.07%	4.78%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.90%	5.40%
4/4/2005	10.00%	4.88%	5.12%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.77%	5.98%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.65%	6.85%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.62%	5.51%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.54%	6.21%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.55%	5.74%
12/21/2005	10.40%	4.55%	5.85%
12/22/2005	11.15%	4.54%	6.61%
12/22/2005	11.00%	4.54%	6.46%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.61%	5.59%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.74%	5.26%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.82%	5.38%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.86%	5.19%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.89%	5.65%
9/14/2006	10.00%	4.90%	5.10%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.50%	4.95%	5.55%
12/1/2006	10.25%	4.95%	5.30%
12/7/2006	10.75%	4.95%	5.80%
12/21/2006	11.25%	4.95%	6.30%
12/21/2006	10.90%	4.95%	5.95%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.87%	6.48%
3/22/2007	9.75%	4.87%	4.88%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.81%	5.44%
5/17/2007	10.25%	4.81%	5.44%
5/22/2007	10.20%	4.81%	5.39%
5/22/2007	10.50%	4.81%	5.69%
5/23/2007	10.70%	4.81%	5.89%
5/25/2007	9.67%	4.81%	4.86%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.85%	5.35%
12/20/2007	10.20%	4.85%	5.35%
12/20/2007	11.00%	4.85%	6.15%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.82%	5.93%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.69%	4.41%
4/22/2008	10.25%	4.61%	5.64%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.59%	6.11%
5/19/2008	11.00%	4.57%	6.43%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	11.04%	4.54%	6.50%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/27/2008	10.50%	4.54%	5.96%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.52%	4.88%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.51%	5.74%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.48%	5.72%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.40%	5.85%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/21/2009	10.50%	4.12%	6.38%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.08%	6.42%
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.97%	6.53%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.86%	7.24%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.79%	6.21%
4/30/2009	11.25%	3.78%	7.47%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.75%	6.50%
5/28/2009	10.50%	3.75%	6.75%
6/22/2009	10.00%	3.77%	6.23%
6/24/2009	10.80%	3.77%	7.03%
7/8/2009	10.63%	3.77%	6.86%
7/17/2009	10.50%	3.78%	6.72%
8/21/2009	10.25%	3.81%	6.44%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.01%	6.69%
10/23/2009	10.88%	4.05%	6.83%
11/2/2009	10.70%	4.09%	6.61%
11/3/2009	10.70%	4.09%	6.61%
11/24/2009	10.25%	4.15%	6.10%
11/25/2009	10.75%	4.15%	6.60%
11/30/2009	10.35%	4.16%	6.19%
12/3/2009	10.50%	4.17%	6.33%
12/7/2009	10.70%	4.18%	6.52%
12/16/2009	11.00%	4.21%	6.79%
12/16/2009	10.90%	4.21%	6.69%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.27%	6.53%
1/11/2010	11.00%	4.30%	6.70%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.40%	4.35%	6.05%
1/27/2010	10.70%	4.35%	6.35%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.42%	5.58%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.46%	5.84%
5/12/2010	10.30%	4.46%	5.84%
5/28/2010	10.20%	4.44%	5.76%
5/28/2010	10.10%	4.44%	5.66%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	10.50%	4.43%	6.07%
6/28/2010	9.67%	4.43%	5.24%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.70%	4.43%	6.27%
7/15/2010	10.53%	4.43%	6.10%
7/30/2010	10.70%	4.41%	6.29%
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.33%	5.67%
9/16/2010	10.00%	4.33%	5.67%
9/30/2010	9.75%	4.29%	5.46%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.20%	6.50%
11/19/2010	10.20%	4.18%	6.02%
11/22/2010	10.00%	4.18%	5.82%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.16%	5.70%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.15%	5.85%
12/20/2010	10.60%	4.15%	6.45%
12/21/2010	10.30%	4.15%	6.15%
12/27/2010	9.90%	4.14%	5.76%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.13%	6.17%
1/13/2011	10.30%	4.13%	6.17%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.12%	5.48%
2/3/2011	10.00%	4.12%	5.88%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.23%	5.44%
4/27/2011	10.40%	4.23%	6.17%
5/4/2011	10.00%	4.24%	5.76%
5/4/2011	10.00%	4.24%	5.76%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.31%	4.89%
6/17/2011	9.95%	4.31%	5.64%
7/13/2011	10.20%	4.36%	5.84%
8/1/2011	9.20%	4.38%	4.82%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.37%	5.63%
8/12/2011	10.35%	4.37%	5.98%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.88%	7.02%
11/30/2011	10.90%	3.88%	7.02%
12/14/2011	10.00%	3.80%	6.20%
12/14/2011	10.30%	3.80%	6.50%
12/20/2011	10.20%	3.77%	6.43%
12/21/2011	10.20%	3.76%	6.44%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.75%	6.44%
1/25/2012	10.50%	3.57%	6.93%
1/27/2012	10.50%	3.56%	6.94%
2/15/2012	10.20%	3.48%	6.72%
2/23/2012	9.90%	3.44%	6.46%
2/27/2012	10.25%	3.43%	6.82%
2/29/2012	10.40%	3.42%	6.98%
3/29/2012	10.37%	3.32%	7.05%
4/4/2012	10.00%	3.30%	6.70%
4/26/2012	10.00%	3.21%	6.79%
5/2/2012	10.00%	3.19%	6.81%
5/7/2012	9.80%	3.17%	6.63%
5/15/2012	10.00%	3.15%	6.85%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.08%	7.22%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.06%	6.54%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/19/2012	9.80%	2.94%	6.86%
9/26/2012	9.50%	2.94%	6.56%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.88%	2.90%	6.98%
11/29/2012	9.75%	2.90%	6.85%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	10.50%	2.88%	7.62%
12/13/2012	9.50%	2.88%	6.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.88%	6.83%
12/19/2012	10.25%	2.88%	7.37%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.45%	2.87%	7.58%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	9.50%	2.87%	6.63%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
1/9/2013	9.70%	2.85%	6.85%
2/13/2013	10.20%	2.85%	7.35%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.07%	6.29%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.25%	3.26%	6.99%
9/11/2013	10.20%	3.26%	6.94%
9/24/2013	10.20%	3.30%	6.90%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.47%	6.73%
12/9/2013	8.72%	3.48%	5.24%
12/9/2013	9.75%	3.48%	6.27%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.50%	6.00%
12/17/2013	10.95%	3.50%	7.45%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.68%	5.52%
2/26/2014	9.75%	3.69%	6.06%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.72%	5.68%
3/26/2014	9.96%	3.72%	6.24%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.57%	6.18%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.45%	6.35%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.36%	6.84%
11/26/2014	9.70%	3.33%	6.37%
11/26/2014	10.20%	3.33%	6.87%
12/4/2014	9.68%	3.31%	6.37%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.29%	6.78%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.27%	6.56%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.96%	6.54%
3/26/2015	9.72%	2.96%	6.76%
4/23/2015	10.20%	2.87%	7.33%
4/29/2015	9.53%	2.86%	6.67%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.30%	2.88%	7.42%
11/19/2015	10.00%	2.88%	7.12%
12/3/2015	10.00%	2.89%	7.11%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.90%	6.70%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.92%	6.58%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.79%	6.21%
6/15/2016	9.00%	2.79%	6.21%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.62%	7.13%
9/1/2016	9.50%	2.60%	6.90%
9/8/2016	10.00%	2.58%	7.42%
9/28/2016	9.58%	2.54%	7.04%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.37%	2.54%	6.83%
12/19/2016	9.00%	2.54%	6.46%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.56%	6.94%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.71%	7.54%
4/12/2017	9.40%	2.73%	6.67%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.94%	6.56%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.93%	6.87%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.88%	5.52%
12/6/2017	8.40%	2.88%	5.52%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.65%	2.87%	6.78%
12/14/2017	9.60%	2.87%	6.73%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.86%	6.72%
12/21/2017	9.10%	2.86%	6.24%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10.00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	9.25%	2.89%	6.36%
4/18/2018	10.00%	2.89%	7.11%
4/26/2018	9.50%	2.90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2.96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2.97%	6.93%
6/28/2018	9.35%	2.97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%
8/24/2018	9.28%	3.00%	6.28%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	9.77%	3.04%	6.73%
9/26/2018	10.00%	3.04%	6.96%
9/27/2018	9.30%	3.05%	6.25%
10/4/2018	9.85%	3.06%	6.79%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5.55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9.84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10.00%	3.13%	6.87%
2/27/2019	9.75%	3.12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3.12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9.73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3.11%	6.89%
5/8/2019	9.50%	3.10%	6.40%
5/14/2019	8.75%	3.10%	5.65%
5/16/2019	9.50%	3.09%	6.41%
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9.60%	2.90%	6.70%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.79%	7.21%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%
11/7/2019	9.35%	2.58%	6.77%
11/29/2019	9.50%	2.53%	6.97%
12/4/2019	8.91%	2.51%	6.40%
12/4/2019	9.75%	2.51%	7.24%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	10.50%	2.48%	8.02%
12/17/2019	9.70%	2.48%	7.22%
12/19/2019	10.25%	2.47%	7.78%
12/19/2019	10.20%	2.47%	7.73%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.45%	2.47%	6.98%
12/20/2019	9.65%	2.47%	7.18%
12/24/2019	9.70%	2.46%	7.24%
1/8/2020	10.02%	2.43%	7.59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9.50%	2.40%	7.10%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.35%	7.65%
2/11/2020	9.30%	2.34%	6.96%
2/14/2020	9.40%	2.33%	7.07%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.30%	7.45%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.18%	7.22%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.03%	7.22%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.85%	7.40%
7/8/2020	9.40%	1.83%	7.57%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.77%	7.73%
8/27/2020	10.00%	1.66%	8.34%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	8.20%	1.66%	6.54%
10/22/2020	9.50%	1.50%	8.00%
10/28/2020	9.60%	1.49%	8.11%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.20%	1.44%	7.76%
11/24/2020	9.80%	1.44%	8.36%
12/9/2020	8.38%	1.43%	6.95%
12/9/2020	8.38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%
12/16/2020	9.50%	1.44%	8.06%
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8.06%
12/22/2020	9.15%	1.45%	7.70%
12/23/2020	10.00%	1.45%	8.55%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
3/31/2021	9.60%	1.67%	7.93%
4/16/2021	9.60%	1.73%	7.87%
5/4/2021	9.85%	1.79%	8.06%
5/18/2021	9.50%	1.84%	7.66%
6/4/2021	9.28%	1.90%	7.38%
6/23/2021	9.00%	1.94%	7.06%
6/28/2021	9.55%	1.95%	7.60%
6/30/2021	9.43%	1.96%	7.47%
6/30/2021	9.43%	1.96%	7.47%
7/14/2021	9.60%	1.99%	7.61%
7/21/2021	9.50%	2.00%	7.50%
8/5/2021	9.60%	2.01%	7.59%
8/18/2021	9.50%	2.03%	7.47%
8/31/2021	8.57%	2.04%	6.53%
9/1/2021	9.40%	2.04%	7.36%
9/27/2021	9.40%	2.07%	7.33%
10/21/2021	9.95%	2.10%	7.85%
10/26/2021	10.60%	2.10%	8.50%
10/28/2021	9.35%	2.10%	7.25%
11/2/2021	8.90%	2.10%	6.80%
11/4/2021	9.48%	2.11%	7.37%
11/17/2021	9.70%	2.11%	7.59%
11/18/2021	9.00%	2.11%	6.89%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/18/2021	9.25%	2.11%	7.14%
11/18/2021	9.35%	2.11%	7.24%
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.11%	7.69%
12/1/2021	7.36%	2.10%	5.26%
12/7/2021	9.65%	2.09%	7.56%
12/13/2021	7.36%	2.08%	5.28%
12/15/2021	9.60%	2.08%	7.52%
12/22/2021	9.90%	2.07%	7.83%
12/28/2021	9.40%	2.05%	7.35%
1/20/2022	9.00%	2.03%	6.97%
2/16/2022	9.35%	2.02%	7.33%
2/23/2022	9.70%	2.02%	7.68%
3/16/2022	9.30%	2.02%	7.28%
4/14/2022	9.20%	2.07%	7.13%
4/25/2022	9.50%	2.11%	7.39%
5/12/2022	9.20%	2.18%	7.02%
5/23/2022	9.50%	2.22%	7.28%
8/31/2022	8.57%	2.64%	5.93%
9/8/2022	9.50%	2.68%	6.82%
9/15/2022	9.35%	2.73%	6.62%
10/4/2022	10.10%	2.84%	7.26%
10/4/2022	10.80%	2.84%	7.96%
10/25/2022	9.50%	2.99%	6.51%
11/3/2022	10.25%	3.06%	7.19%
11/3/2022	10.20%	3.06%	7.14%
11/3/2022	10.30%	3.06%	7.24%
11/17/2022	7.85%	3.16%	4.69%
11/18/2022	9.90%	3.16%	6.74%
11/30/2022	9.80%	3.22%	6.58%
12/1/2022	7.85%	3.23%	4.62%
12/14/2022	9.60%	3.29%	6.31%
12/14/2022	9.50%	3.29%	6.21%
12/14/2022	10.00%	3.29%	6.71%
12/15/2022	10.00%	3.29%	6.71%
12/15/2022	9.95%	3.29%	6.66%
12/15/2022	10.05%	3.29%	6.76%
12/16/2022	9.50%	3.30%	6.20%
12/20/2022	10.50%	3.31%	7.19%
12/22/2022	9.40%	3.32%	6.08%
12/22/2022	9.80%	3.32%	6.48%
12/27/2022	9.56%	3.35%	6.21%
12/29/2022	9.30%	3.36%	5.94%
12/29/2022	9.80%	3.36%	6.44%
1/19/2023	9.90%	3.44%	6.46%
1/23/2023	9.65%	3.45%	6.20%
1/26/2023	9.75%	3.46%	6.29%
2/9/2023	9.60%	3.49%	6.11%
2/17/2023	9.50%	3.52%	5.98%
3/9/2023	9.70%	3.58%	6.12%
3/24/2023	9.90%	3.60%	6.30%
4/27/2023	10.00%	3.66%	6.34%
5/31/2023	9.35%	3.76%	5.59%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/1/2023	9.25%	3.76%	5.49%
6/6/2023	9.35%	3.77%	5.58%
6/6/2023	9.75%	3.77%	5.98%
7/20/2023	9.25%	3.82%	5.43%
8/2/2023	9.80%	3.81%	5.99%
8/3/2023	9.57%	3.81%	5.76%
8/18/2023	9.80%	3.82%	5.98%
8/23/2023	9.58%	3.82%	5.76%
8/25/2023	9.55%	3.83%	5.72%
8/25/2023	8.63%	3.83%	4.80%
8/31/2023	11.45%	3.84%	7.61%
8/31/2023	9.40%	3.84%	5.56%
9/6/2023	9.30%	3.85%	5.45%
9/21/2023	9.65%	3.89%	5.76%
10/12/2023	9.75%	3.97%	5.78%
10/12/2023	9.20%	3.97%	5.23%
10/12/2023	9.20%	3.97%	5.23%
10/18/2023	9.50%	3.99%	5.51%
10/19/2023	9.50%	4.00%	5.50%
10/25/2023	9.65%	4.03%	5.62%
11/3/2023	9.30%	4.07%	5.23%
11/3/2023	9.70%	4.07%	5.63%
11/9/2023	9.80%	4.09%	5.71%
11/9/2023	9.80%	4.09%	5.71%
11/17/2023	9.60%	4.12%	5.48%
11/28/2023	9.35%	4.15%	5.20%
12/1/2023	9.90%	4.16%	5.74%
12/7/2023	9.70%	4.16%	5.54%
12/14/2023	10.00%	4.17%	5.83%
12/14/2023	8.72%	4.17%	4.55%
12/14/2023	8.91%	4.17%	4.74%
12/14/2023	9.50%	4.17%	5.33%
12/15/2023	10.10%	4.17%	5.93%
12/18/2023	9.50%	4.17%	5.33%
12/22/2023	10.70%	4.18%	6.52%
12/22/2023	10.65%	4.18%	6.47%
12/22/2023	10.75%	4.18%	6.57%
12/26/2023	9.52%	4.18%	5.34%
12/28/2023	9.60%	4.19%	5.41%
1/3/2024	9.26%	4.19%	5.07%
1/19/2024	9.75%	4.23%	5.52%
1/30/2024	9.75%	4.25%	5.50%
2/14/2024	9.60%	4.28%	5.32%
2/28/2024	9.70%	4.31%	5.39%
3/1/2024	9.90%	4.31%	5.59%
3/5/2024	9.55%	4.32%	5.23%
3/26/2024	9.80%	4.35%	5.45%
4/17/2024	9.90%	4.40%	5.50%
4/18/2024	9.60%	4.41%	5.19%
5/8/2024	9.85%	4.46%	5.39%
6/10/2024	9.50%	4.49%	5.01%
6/20/2024	9.94%	4.50%	5.44%
6/28/2024	9.40%	4.50%	4.90%
7/2/2024	9.86%	4.50%	5.36%
7/18/2024	9.50%	4.48%	5.02%
8/8/2024	9.94%	4.43%	5.51%
8/21/2024	10.30%	4.40%	5.90%
8/26/2024	9.97%	4.40%	5.57%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/17/2024	9.87%	4.36%	5.51%
9/18/2024	9.74%	4.36%	5.38%
9/23/2024	9.50%	4.36%	5.14%
9/26/2024	9.86%	4.36%	5.50%
9/30/2024	9.35%	4.36%	4.99%
10/3/2024	9.76%	4.36%	5.40%
10/9/2024	9.60%	4.37%	5.23%
10/10/2024	9.86%	4.37%	5.49%
10/17/2024	10.28%	4.38%	5.90%
10/17/2024	10.23%	4.38%	5.85%
10/17/2024	10.33%	4.38%	5.95%
10/24/2024	9.78%	4.38%	5.40%
11/20/2024	9.75%	4.40%	5.35%
11/25/2024	9.50%	4.41%	5.09%
11/26/2024	9.50%	4.41%	5.09%
12/3/2024	10.50%	4.41%	6.09%
12/19/2024	9.50%	4.42%	5.08%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/20/2024	9.34%	4.42%	4.92%
12/20/2024	9.80%	4.42%	5.38%
12/30/2024	10.10%	4.43%	5.67%
1/14/2025	9.95%	4.45%	5.50%
1/15/2025	9.50%	4.45%	5.05%
1/15/2025	9.90%	4.45%	5.45%
1/16/2025	10.00%	4.46%	5.54%
1/23/2025	9.90%	4.46%	5.44%
1/29/2025	9.75%	4.46%	5.29%
2/3/2025	9.80%	4.46%	5.34%
3/4/2025	10.20%	4.46%	5.74%
3/12/2025	9.40%	4.46%	4.94%
3/13/2025	9.35%	4.46%	4.89%
3/13/2025	9.65%	4.46%	5.19%
3/20/2025	9.75%	4.47%	5.28%
3/21/2025	9.90%	4.47%	5.43%
3/25/2025	9.10%	4.47%	4.63%
4/25/2025	9.38%	4.50%	4.88%
5/15/2025	9.45%	4.53%	4.92%
6/2/2025	9.50%	4.58%	4.92%
6/26/2025	9.75%	4.65%	5.10%
7/25/2025	9.50%	4.73%	4.77%
8/14/2025	9.50%	4.75%	4.75%
8/14/2025	9.50%	4.75%	4.75%
8/28/2025	9.25%	4.77%	4.48%
8/29/2025	9.60%	4.77%	4.83%
8/29/2025	9.94%	4.77%	5.17%
9/16/2025	9.51%	4.79%	4.72%
10/2/2025	9.80%	4.80%	5.00%
10/28/2025	9.25%	4.78%	4.47%
11/5/2025	10.00%	4.77%	5.23%
11/6/2025	9.80%	4.77%	5.03%

[6]	[7]	[8]	[9]
Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/6/2025	9.80%	4.77%	5.03%
11/19/2025	9.65%	4.77%	4.88%
11/19/2025	9.63%	4.77%	4.86%
11/19/2025	9.63%	4.77%	4.86%
11/19/2025	9.63%	4.77%	4.86%
11/20/2025	10.95%	4.77%	6.18%
11/20/2025	9.99%	4.77%	5.22%
11/20/2025	9.80%	4.77%	5.03%
11/21/2025	9.60%	4.77%	4.83%
11/25/2025	9.80%	4.77%	5.03%
12/4/2025	9.99%	4.77%	5.22%
12/18/2025	9.98%	4.78%	5.20%
12/18/2025	9.93%	4.78%	5.15%
12/18/2025	10.03%	4.78%	5.25%
12/30/2025	9.60%	4.79%	4.81%
# of Cases:			1,851

2025-2029 CAPITAL EXPENDITURES AS A PERCENT OF 2024 NET PLANT
(\$ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2024	2025	2026	2027	2028	2029	2025-2029 Cap. Ex. / 2024 Net Plant
Alliant Energy Corporation	LNT							
Capital Spending per Share			\$5.60	\$5.60	\$5.53	\$5.47	\$5.40	
Common Shares Outstanding			257.10	257.50	\$258.00	\$258.50	259.00	
Capital Expenditures			\$1,439.8	\$1,442.0	\$1,427.6	\$1,413.1	\$1,398.6	38.08%
Net Plant		\$18,701.0						
Ameren Corporation	AEE							
Capital Spending per Share			\$12.80	\$12.85	\$12.90	\$12.95	\$13.00	
Common Shares Outstanding			272.00	275.00	\$278.33	\$281.67	285.00	
Capital Expenditures			\$3,481.6	\$3,533.8	\$3,590.5	\$3,647.6	\$3,705.0	49.37%
Net Plant		\$36,376.0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			\$14.10	\$14.10	\$14.07	\$14.03	\$14.00	
Common Shares Outstanding			535.00	540.00	\$543.33	\$546.67	550.00	
Capital Expenditures			\$7,543.5	\$7,614.0	\$7,642.9	\$7,671.6	\$7,700.0	46.32%
Net Plant		\$82,416.0						
Avista Corporation	AVA							
Capital Spending per Share			\$6.55	\$7.00	\$7.83	\$8.67	\$9.50	
Common Shares Outstanding			81.50	83.00	\$83.67	\$84.33	85.00	
Capital Expenditures			\$533.8	\$581.0	\$655.4	\$730.9	\$807.5	54.96%
Net Plant		\$6,020.0						
CMS Energy Corporation	CMS							
Capital Spending per Share			\$13.15	\$16.40	\$17.47	\$18.53	\$19.60	
Common Shares Outstanding			304.50	305.00	\$305.33	\$305.67	306.00	
Capital Expenditures			\$4,004.2	\$5,002.0	\$5,333.2	\$5,665.0	\$5,997.6	94.69%
Net Plant		\$27,461.0						
CenterPoint Energy, Inc.	CNP							
Capital Spending per Share			\$8.45	\$8.50	\$8.50	\$8.50	\$8.50	
Common Shares Outstanding			653.00	653.00	\$653.00	\$653.00	653.00	
Capital Expenditures			\$5,517.9	\$5,550.5	\$5,550.5	\$5,550.5	\$5,550.5	86.38%
Net Plant		\$32,089.0						
Consolidated Edison, Inc.	ED							
Capital Spending per Share			\$13.85	\$15.20	\$15.15	\$15.10	\$15.05	
Common Shares Outstanding			360.70	361.50	\$362.67	\$363.83	365.00	
Capital Expenditures			\$4,995.7	\$5,494.8	\$5,494.4	\$5,493.9	\$5,493.3	51.71%
Net Plant		\$52,165.0						
Dominion Energy, Inc.	D							
Capital Spending per Share			\$12.40	\$11.00	\$11.00	\$11.00	\$11.00	
Common Shares Outstanding			855.00	858.00	\$865.33	\$872.67	880.00	
Capital Expenditures			\$10,602.0	\$9,438.0	\$9,518.7	\$9,599.3	\$9,680.0	70.92%
Net Plant		\$68,862.0						
DTE Energy Company	DTE							
Capital Spending per Share			\$17.75	\$17.95	\$18.13	\$18.32	\$18.50	
Common Shares Outstanding			205.50	205.50	\$205.67	\$205.83	206.00	
Capital Expenditures			\$3,647.6	\$3,688.7	\$3,729.4	\$3,770.2	\$3,811.0	59.99%
Net Plant		\$31,081.0						
Duke Energy Corporation	DUK							
Capital Spending per Share			\$16.30	\$16.75	\$17.25	\$17.75	\$18.25	
Common Shares Outstanding			777.60	778.00	\$778.67	\$779.33	780.00	
Capital Expenditures			\$12,674.9	\$13,031.5	\$13,432.0	\$13,833.2	\$14,235.0	54.51%
Net Plant		\$123,303.0						
Entergy Corporation	ETR							
Capital Spending per Share			\$12.00	\$12.50	\$13.00	\$13.50	\$14.00	
Common Shares Outstanding			435.00	440.00	\$446.67	\$453.33	460.00	
Capital Expenditures			\$5,220.0	\$5,500.0	\$5,806.7	\$6,120.0	\$6,440.0	61.33%
Net Plant		\$47,423.0						
Eversource Energy	ES							
Capital Spending per Share			\$12.25	\$12.50	\$12.75	\$13.00	\$13.25	
Common Shares Outstanding			371.50	373.00	\$375.33	\$377.67	380.00	
Capital Expenditures			\$4,550.9	\$4,662.5	\$4,785.5	\$4,909.7	\$5,035.0	58.42%
Net Plant		\$40,987.0						
Exelon Corporation	EXC							
Capital Spending per Share			\$7.80	\$7.85	\$7.90	\$7.95	\$8.00	
Common Shares Outstanding			1005.00	1005.00	\$1,005.00	\$1,005.00	1005.00	
Capital Expenditures			\$7,839.0	\$7,889.3	\$7,939.5	\$7,989.8	\$8,040.0	50.78%
Net Plant		\$78,182.0						
FirstEnergy Corporation	FE							
Capital Spending per Share			\$8.25	\$8.25	\$8.58	\$8.92	\$9.25	
Common Shares Outstanding			580.00	585.00	\$588.33	\$591.67	595.00	
Capital Expenditures			\$4,785.0	\$4,826.3	\$5,049.9	\$5,275.7	\$5,503.8	61.90%
Net Plant		\$41,102.0						

IDACORP, Inc.	IDA						
Capital Spending per Share		\$18.35	\$18.25	\$20.50	\$22.75	\$25.00	
Common Shares Outstanding		54.50	55.00	\$55.33	\$55.67	56.00	
Capital Expenditures		\$1,000.1	\$1,003.8	\$1,134.3	\$1,266.4	\$1,400.0	89.06%
Net Plant		\$6,517.3					
NextEra Energy, Inc.	NEE						
Capital Spending per Share		\$11.00	\$11.00	\$11.33	\$11.67	\$12.00	
Common Shares Outstanding		2065.00	2100.00	\$2,133.33	\$2,166.67	2200.00	
Capital Expenditures		\$22,715.0	\$23,100.0	\$24,177.8	\$25,277.8	\$26,400.0	87.63%
Net Plant		\$138,852.0					
OGE Energy Corporation	OGE						
Capital Spending per Share		\$4.75	\$4.75	\$4.75	\$4.75	\$4.75	
Common Shares Outstanding		200.20	200.20	\$200.20	\$200.20	200.20	
Capital Expenditures		\$951.0	\$951.0	\$951.0	\$951.0	\$951.0	41.21%
Net Plant		\$11,538.0					
Pinnacle West Capital Corporation	PNW						
Capital Spending per Share		\$16.75	\$17.00	\$17.17	\$17.33	\$17.50	
Common Shares Outstanding		120.50	122.00	\$123.00	\$124.00	125.00	
Capital Expenditures		\$2,018.4	\$2,074.0	\$2,111.5	\$2,149.3	\$2,187.5	54.91%
Net Plant		\$19,198.0					
Portland General Electric Company	POR						
Capital Spending per Share		\$11.50	\$11.50	\$11.50	\$11.50	\$11.50	
Common Shares Outstanding		111.00	114.00	\$116.00	\$118.00	120.00	
Capital Expenditures		\$1,276.5	\$1,311.0	\$1,334.0	\$1,357.0	\$1,380.0	64.36%
Net Plant		\$10,345.0					
Public Service Enterprise Group Inc.	PEG						
Capital Spending per Share		\$7.75	\$8.50	\$8.67	\$8.83	\$9.00	
Common Shares Outstanding		500.00	501.00	\$502.33	\$503.67	505.00	
Capital Expenditures		\$3,875.0	\$4,258.5	\$4,353.6	\$4,449.1	\$4,545.0	53.62%
Net Plant		\$40,064.0					
Southern Company	SO						
Capital Spending per Share		\$8.75	\$8.70	\$8.63	\$8.57	\$8.50	
Common Shares Outstanding		1105.00	1110.00	\$1,113.33	\$1,116.67	1120.00	
Capital Expenditures		\$9,668.8	\$9,657.0	\$9,611.8	\$9,566.1	\$9,520.0	48.01%
Net Plant		\$100,028.0					
Xcel Energy Inc.	XEL						
Capital Spending per Share		\$15.70	\$13.50	\$13.33	\$13.17	\$13.00	
Common Shares Outstanding		591.50	593.50	\$595.67	\$597.83	600.00	
Capital Expenditures		\$9,286.6	\$8,012.3	\$7,942.2	\$7,871.5	\$7,800.0	71.53%
Net Plant		\$57,198.0					
PPL Electric	PPL Elec						
Capital Expenditures [8]		\$1,580.77	\$1,893.66	\$1,849.91	\$1,784.14	\$1,603.79	63.09%
Net Plant [9]		\$13,808.8					
		2025	2026	2027	2028	2029	
PPL CapEx Total (2025 - 2029)							\$8,712.3
PPL CapEx Annual Average							\$1,742.5
Proxy Group Median							54.96%
PPL / Proxy Group Median							1.15

Notes:

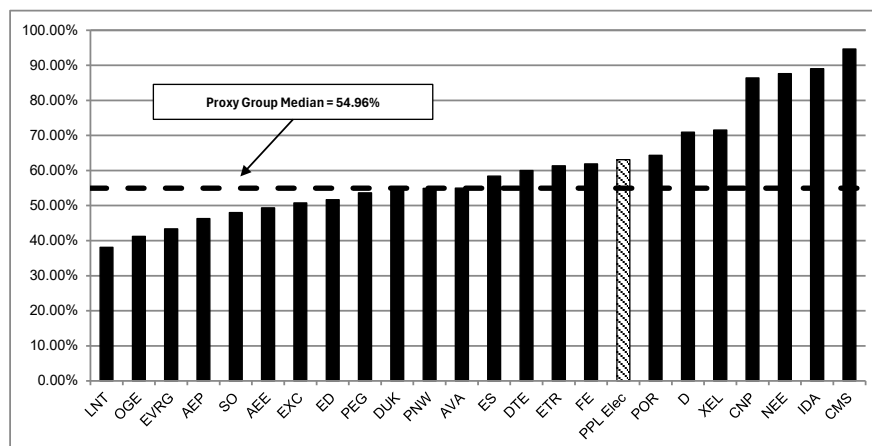
[1] - [6] Source: Value Line, dated October 17, 2025, November 7, 2025, December 5, 2025; Evergy net plant from Evergy 2024 Report 10-K at 75.

[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]

[8] Source: Company Provided Data

[9] Source: 2024 PPL Electric Utilities Co. FERC Form 1, pp. 108-109, Line 6 Net Utility Plant

TURES AS A PERCENT OF 2024 NET PLANT



Projected CAPEX / 2024 Net Plant

Rank	Company	Ticker	2025-2029
1	Alliant Energy Corporation	LNT	38.08%
2	OGE Energy Corporation	OGE	41.21%
3	Evergy, Inc.	EVRG	43.36%
4	American Electric Power Company, Inc.	AEP	46.32%
5	Southern Company	SO	48.01%
6	Ameren Corporation	AEE	49.37%
7	Exelon Corporation	EXC	50.78%
8	Consolidated Edison, Inc.	ED	51.71%
9	Public Service Enterprise Group Inc.	PEG	53.62%
10	Duke Energy Corporation	DUK	54.51%
11	Pinnacle West Capital Corporation	PNW	54.91%
12	Avista Corporation	AVA	54.96%
13	Eversource Energy	ES	58.42%
14	DTE Energy Company	DTE	59.99%
15	Entergy Corporation	ETR	61.33%
16	FirstEnergy Corporation	FE	61.90%
17	PPL Electric	PPL Elec	63.09%
18	Portland General Electric Company	POR	64.36%
19	Dominion Energy, Inc.	D	70.92%
20	Xcel Energy Inc.	XEL	71.53%
21	CenterPoint Energy, Inc.	CNP	86.38%
22	NextEra Energy, Inc.	NEE	87.63%
23	IDACORP, Inc.	IDA	89.06%
24	CMS Energy Corporation	CMS	94.69%
Proxy Group Median			54.96%
PPL Electric/Proxy Group			1.15

Proxy Group Regulatory Risk Comparative Assessment

				Adjustment Clauses									Ratemaking Framework Component	
				Fuel / Purchased Power	Volumetric Risk Mitigation [1]	New Capital Investment [2]	Storm / Natural Disaster Damage Expense	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]	Jurisdiction Test Year	Jurisdiction Rate Base Methodology	
Company	Parent	Jurisdiction	Service											
Ameren Illinois Company	AEE	Illinois	Electric	✓	✓	✓		✓	✓	✓	✓	Forecast Permitted	Year End	
Union Electric Company	AEE	Missouri	Electric	✓	✓	✓		✓	✓	✓	✓	Partially Forecast	Year End	
Southwestern Electric Power Company	AEP	Arkansas	Electric	✓	✓	✓		✓		✓	✓	Forecast Permitted	Year End	
Indiana Michigan Power Company	AEP	Indiana	Electric	✓	✓	✓		✓	✓	✓	✓	Forecast Permitted	Year End	
Kentucky Power Company	AEP	Kentucky	Electric	✓	✓	✓		✓	✓	✓	✓	Historical	Year End	
Southwestern Electric Power Company	AEP	Louisiana	Electric	✓	✓	✓	✓	✓	✓	✓	✓	Historical	Average	
Indiana Michigan Power Company	AEP	Michigan	Electric	✓	✓	✓		✓	✓	✓	✓	Fully Forecast	Average	
Ohio Power Company	AEP	Ohio	Electric	✓	✓	✓	✓	✓	✓		✓	Partially Forecast	Year End	
Public Service Company of Oklahoma	AEP	Oklahoma	Electric	✓	✓	✓	✓	✓	✓		✓	Historical	Year End	
Kingsport Power Company	AEP	Tennessee	Electric	✓		✓	✓				✓	Fully Forecast	Average	
AEP Texas Inc.	AEP	Texas	Electric	NA		✓		✓		✓	✓	Historical	Year End	
Southwestern Electric Power Company	AEP	Texas	Electric	✓		✓		✓	✓		✓	Historical	Year End	
Appalachian Power Company	AEP	Virginia	Electric	✓		✓		✓	✓	✓	✓	Forecast Permitted	Average	
Appalachian Power / Wheeling Power	AEP	West Virginia	Electric	✓		✓		✓	✓	✓	✓	Historical	Average	
Alaska Electric Light and Power Company	AVA	Alaska	Electric	✓							✓	Historical	Average	
Avista Corporation	AVA	Idaho	Electric	✓	✓			✓			✓	Historical	Average	
Avista Corporation	AVA	Washington	Electric	✓	✓	✓	✓	✓	✓		✓	Forecast Permitted	Average	
Consumers Energy Company	CMS	Michigan	Electric	✓				✓	✓		✓	Fully Forecast	Average	
Southern Indiana Gas & Electric Co.	CNP	Indiana	Electric	✓	✓	✓		✓		✓	✓	Historical	Year End	
CenterPoint Energy Houston Electric LLC	CNP	Texas	Electric	NA		✓		✓			✓	Historical	Year End	
Dominion Energy South Carolina	D	South Carolina	Electric	✓				✓	✓	✓	✓	Historical	Year End	
Dominion Energy North Carolina	D	North Carolina	Electric	✓	✓			✓	✓	✓	✓	Historical	Year End	
Virginia Electric and Power Company	D	Virginia	Electric	✓		✓		✓	✓	✓	✓	Forecast Permitted	Average	
DTE Electric Company	DTE	Michigan	Electric	✓		✓		✓	✓	✓	✓	Fully Forecast	Average	
Duke Energy Florida, LLC	DUK	Florida	Electric	✓			✓	✓	✓	✓	✓	Partially Forecast	Average	
Duke Energy Indiana, LLC	DUK	Indiana	Electric	✓	✓	✓		✓	✓	✓	✓	Forecast Permitted	Year End	
Duke Energy Kentucky, Inc.	DUK	Kentucky	Electric	✓	✓			✓	✓	✓	✓	Historical	Year End	
Duke Energy Carolinas, LLC	DUK	North Carolina	Electric	✓	✓		✓	✓	✓	✓	✓	Historical	Year End	
Duke Energy Progress, LLC	DUK	North Carolina	Electric	✓	✓	✓	✓	✓	✓	✓	✓	Historical	Year End	
Duke Energy Ohio, Inc.	DUK	Ohio	Electric	✓	✓	✓	✓	✓	✓		✓	Partially Forecast	Year End	
Duke Energy Carolinas, LLC	DUK	South Carolina	Electric	✓	✓			✓	✓	✓	✓	Historical	Year End	
Duke Energy Progress, LLC	DUK	South Carolina	Electric	✓	✓			✓	✓	✓	✓	Historical	Year End	
Rockland Electric Co.	ED	New Jersey	Electric	✓	✓		✓			✓	✓	Partially Forecast	Year End	
Consolidated Edison Co. of New York Inc.	ED	New York	Electric	✓	✓			✓	✓		✓	Fully Forecast	Average	
Orange & Rockland Utilities Inc.	ED	New York	Electric	✓	✓			✓	✓		✓	Fully Forecast	Average	
Public Service Co. of New Hampshire	ES	New Hampshire	Electric	✓	✓			✓			✓	Historical	Year End	
Connecticut Light and Power Co.	ES	Connecticut	Electric	✓	✓			✓			✓	Historical	Year End	
NSTAR Electric Co.	ES	Massachusetts	Electric	✓	✓	✓	✓	✓	✓		✓	Historical	Year End	
Entergy Arkansas, LLC	ETR	Arkansas	Electric	✓	✓	✓	✓	✓		✓	✓	Forecast Permitted	Year End	
Entergy Louisiana, LLC	ETR	Louisiana	Electric	✓	✓	✓	✓	✓		✓	✓	Historical	Average	
Entergy Mississippi, LLC	ETR	Mississippi	Electric	✓	✓	✓	✓	✓			✓	Forecast Permitted	Average	
Entergy New Orleans, LLC	ETR	Louisiana - NOCC	Electric	✓	✓	✓	✓	✓		✓	✓	Forecast Permitted	Average	
Entergy Texas, Inc.	ETR	Texas	Electric	✓		✓	✓	✓			✓	Historical	Year End	
Evergy Kansas Central	EVRG	Kansas	Electric	✓	✓			✓		✓	✓	Historical	Year End	
Evergy Kansas Metro	EVRG	Kansas	Electric	✓				✓		✓	✓	Historical	Year End	
Evergy Missouri Metro	EVRG	Missouri	Electric	✓	✓	✓		✓		✓	✓	Partially Forecast	Year End	
Evergy Missouri West	EVRG	Missouri	Electric	✓	✓			✓	✓	✓	✓	Partially Forecast	Year End	
Delmarva Power & Light Co.	EXC	Delaware	Electric	✓		✓		✓			✓	Historical	Average	
Potomac Electric Power Co.	EXC	District of Columbia	Electric	✓	✓			✓	✓		✓	Historical	Average	
Commonwealth Edison Co.	EXC	Illinois	Electric	✓	✓	✓		✓		✓	✓	Historical	Year End	
Baltimore Gas & Electric Co.	EXC	Maryland	Electric	✓	✓			✓			✓	Historical	Average	
Delmarva Power & Light Co.	EXC	Maryland	Electric	✓	✓			✓		✓	✓	Historical	Average	
Potomac Electric Power Co.	EXC	Maryland	Electric	✓	✓			✓		✓	✓	Historical	Average	
Atlantic City Electric Co.	EXC	New Jersey	Electric	✓	✓	✓				✓	✓	Partially Forecast	Year End	
PECO Energy Co.	EXC	Pennsylvania	Electric	✓		✓		✓			✓	Fully Forecast	Year End	

Company	Parent	Jurisdiction	Service	Adjustment Clauses								Ratemaking Framework Component	
				Fuel / Purchased Power	Volumetric Risk Mitigation [1]	New Capital Investment [2]	Storm / Natural Disaster Damage Expense	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]	Jurisdiction Test Year	Jurisdiction Rate Base Methodology
				✓				✓	✓		✓		
Cleveland Electric Illuminating Company	FE	Ohio	Electric	✓		✓		✓	✓		✓	Partially Forecast	Year End
Jersey Central Power & Light Company	FE	New Jersey	Electric	✓	✓	✓		✓	✓	✓	✓	Partially Forecast	Year End
Ohio Edison Company	FE	Ohio	Electric	✓		✓		✓	✓		✓	Partially Forecast	Year End
FirstEnergy Pennsylvania Electric Co.	FE	Pennsylvania	Electric	✓		✓		✓			✓	Fully Forecast	Year End
Monongahela Power Company	FE	West Virginia	Electric	✓					✓	✓	✓	Historical	Average
Potomac Edison Company	FE	Maryland	Electric	✓				✓	✓	✓	✓	Forecast Permitted	Average
Potomac Edison Company	FE	West Virginia	Electric	✓					✓	✓	✓	Historical	Year End
Toledo Edison Company	FE	Ohio	Electric	✓		✓		✓	✓		✓	Partially Forecast	Year End
Idaho Power Co.	IDA	Idaho	Electric	✓	✓		✓	✓			✓	Historical	Average
Idaho Power Co.	IDA	Oregon	Electric	✓			✓	✓	✓		✓	Partially Forecast	Average
Interstate Power and Light Company	LNT	Iowa	Electric	✓		✓			✓	✓	✓	Historical	Year End
Wisconsin Power and Light Company	LNT	Wisconsin	Electric	✓							✓	Fully Forecast	Average
Florida Power & Light Company	NEE	Florida	Electric	✓		✓	✓	✓	✓	✓	✓	Partially Forecast	Average
Oklahoma Gas and Electric Company	OGE	Arkansas	Electric	✓	✓	✓		✓		✓	✓	Forecast Permitted	Year End
Oklahoma Gas and Electric Company	OGE	Oklahoma	Electric	✓	✓	✓	✓	✓			✓	Historical	Year End
Public Service Electric & Gas Co.	PEG	New Jersey	Electric	✓	✓	✓		✓		✓	✓	Partially Forecast	Year End
Arizona Public Service Company	PNW	Arizona	Electric	✓	✓	✓		✓	✓	✓	✓	Historical	Year End
Portland General Electric Company	POR	Oregon	Electric	✓	✓	✓	✓	✓	✓	✓	✓	Partially Forecast	Average
Alabama Power Company	SO	Alabama	Electric	✓	✓	✓	✓	✓		✓	✓	Historical	Year End
Georgia Power Company	SO	Georgia	Electric	✓		✓		✓		✓	✓	Fully Forecast	Average
Mississippi Power Company	SO	Mississippi	Electric	✓	✓	✓	✓		✓	✓	✓	Forecast Permitted	Average
Public Service Company of Colorado	XEL	Colorado	Electric	✓	✓	✓	✓	✓	✓	✓	✓	Historical	Average
Northern States Power Company - WI	XEL	Michigan	Electric	✓				✓	✓		✓	Fully Forecast	Average
Northern States Power Company - MN	XEL	Minnesota	Electric	✓	✓	✓		✓	✓	✓	✓	Fully Forecast	Average
Southwestern Public Service Company	XEL	New Mexico	Electric	✓		✓		✓			✓	Forecast Permitted	Average
Northern States Power Company - MN	XEL	North Dakota	Electric	✓		✓			✓		✓	Partially Forecast	Average
Northern States Power Company - MN	XEL	South Dakota	Electric	✓	✓			✓		✓	✓	Historical	Average
Southwestern Public Service Company	XEL	Texas	Electric	✓		✓		✓			✓	Historical	Year End
Northern States Power Company - WI	XEL	Wisconsin	Electric	✓							✓	Fully Forecast	Average

% of Proxy Group	100%	62%	67%	29%	85%	57%	60%	100%	52%	55%
									% Partial or Fully Forecast	% Year End Rate Base

PPL Electric Utilities Corporation	PPL	Pennsylvania	Electric	✓		✓	✓	✓			✓	Fully Forecast	Year End

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D electric utilities do not have retail obligation, thus do not need a fuel or purchased power cost recovery

[1] Volumetric Risk Mitigation mechanisms include full or partial decoupling, straight fixed variable rate design, weather normalization adjustment clauses, recovery of lost revenues as a result of Energy Efficiency programs, and earnings true-up mechanisms, such as formula rate plans or annual rate review riders.

[2] Includes recovery of capital investment related to new generation projects, transmission capital, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.

[4] Recovers costs associated with renewable energy projects, distributed energy resources, REC purchases, net metering, RPS expense, and renewable PPAs.

[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear/coal plant decommissioning, and other costs to comply with state and federal environmental mandates.

[6] Cost recovery for items such as pension expenses, bad debt expense, low income programs, vegetation management, RTO/transmission expense (not capital), government & franchise fees and taxes, and regulatory fees.

Sources: Regulatory Research Associates, Adjustment Clauses: A State-by-State Overview, September 22, 2025; Regulatory Research Associates Quarterly State Regulatory Evaluations - July 2025; RRA - Commission Profiles; SEC Form 10-Ks; Company tariffs.

Capital Structure Analysis

COMMON EQUITY RATIO [1]								
Proxy Group Company	Ticker	2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Alliant Energy Corporation	LNT	52.71%	52.10%	52.60%	51.32%	52.51%	52.47%	52.25%
Ameren Corporation	AEE	53.52%	53.94%	53.66%	53.72%	53.09%	53.70%	53.58%
American Electric Power Company, Inc.	AEP	48.58%	48.45%	48.56%	47.76%	48.15%	48.53%	48.30%
Avista Corporation	AVA	50.45%	50.24%	51.06%	50.79%	50.99%	50.58%	50.71%
CenterPoint Energy, Inc.	CNP	46.23%	46.20%	46.73%	44.89%	45.08%	46.39%	45.83%
CMS Energy Corporation	CMS	48.71%	49.10%	49.78%	52.28%	51.17%	49.19%	50.21%
Consolidated Edison, Inc.	ED	45.95%	47.50%	46.73%	46.87%	46.77%	46.73%	46.76%
Dominion Energy, Inc.	D	53.40%	55.08%	52.25%	53.04%	53.16%	53.58%	53.39%
DTE Energy Company	DTE	49.79%	49.72%	50.41%	49.83%	49.45%	49.97%	49.84%
Duke Energy Corporation	DUK	53.08%	52.87%	53.04%	53.39%	52.95%	53.00%	53.07%
Entergy Corporation	ETR	51.30%	51.96%	47.65%	45.48%	46.32%	50.30%	48.54%
Eversource Energy	ES	56.69%	57.02%	56.45%	54.50%	54.61%	56.72%	55.85%
Exelon Corporation	EXC	52.89%	53.27%	53.42%	53.30%	53.19%	53.19%	53.21%
FirstEnergy Corporation	FE	58.94%	54.19%	55.52%	55.24%	56.98%	56.22%	56.18%
Evergy, Inc.	EVRG	59.43%	58.84%	60.20%	60.04%	58.66%	59.49%	59.43%
IDACORP, Inc.	IDA	49.95%	49.42%	54.37%	55.00%	53.96%	51.24%	52.54%
NextEra Energy, Inc.	NEE	59.98%	58.67%	63.14%	62.12%	60.04%	60.60%	60.79%
OGE Energy Corporation	OGE	53.25%	53.53%	55.65%	53.38%	53.04%	54.14%	53.77%
Pinnacle West Capital Corporation	PNW	52.22%	49.56%	50.25%	51.12%	51.35%	50.68%	50.90%
Portland General Electric Company	POR	45.57%	45.37%	43.24%	45.09%	46.07%	44.73%	45.07%
Public Service Enterprise Group Inc.	PEG	55.03%	55.40%	55.16%	55.17%	54.54%	55.20%	55.06%
Southern Company	SO	55.54%	54.82%	54.58%	54.38%	54.66%	54.98%	54.80%
Xcel Energy Inc.	XEL	54.24%	54.47%	54.84%	54.41%	54.82%	54.52%	54.56%
Proxy Group								
MEAN		52.50%	52.25%	52.58%	52.31%	52.24%	52.44%	52.38%
MEDIAN		52.89%	52.87%	53.04%	53.30%	53.04%	53.00%	53.07%
LOW		45.57%	45.37%	43.24%	44.89%	45.08%	44.73%	45.07%
HIGH		59.98%	58.84%	63.14%	62.12%	60.04%	60.60%	60.79%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]								
Company Name	Ticker	2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Interstate Power and Light Company	LNT	51.73%	49.74%	50.55%	50.22%	52.34%	50.67%	50.91%
Wisconsin Power and Light Company	LNT	53.82%	54.77%	55.03%	52.86%	52.78%	54.54%	53.85%
Ameren Illinois Company	AEE	55.36%	56.21%	55.63%	55.78%	55.18%	55.73%	55.63%
Union Electric Company	AEE	51.92%	51.87%	51.88%	51.87%	51.22%	51.89%	51.75%
AEP Texas, Inc.	AEP	43.47%	45.69%	42.07%	42.81%	42.41%	43.74%	43.29%
Appalachian Power Company	AEP	50.26%	48.44%	47.76%	48.34%	47.19%	48.82%	48.40%
Indiana Michigan Power Company	AEP	50.18%	48.32%	49.29%	47.38%	48.67%	49.26%	48.77%
Kentucky Power Company	AEP	44.93%	42.26%	43.82%	44.17%	45.28%	43.67%	44.09%
Kingsport Power Company	AEP	52.99%	51.12%	53.89%	54.18%	53.42%	52.67%	53.12%
Ohio Power Company	AEP	50.95%	51.30%	50.79%	48.76%	52.42%	51.01%	50.84%
Public Service Company of Oklahoma	AEP	48.32%	51.75%	55.70%	54.36%	52.88%	51.92%	52.60%
Southwestern Electric Power Company	AEP	51.55%	50.68%	52.54%	48.70%	50.78%	51.59%	50.85%
Wheeling Power Company	AEP	44.66%	39.99%	49.14%	54.01%	54.10%	44.60%	48.38%
Alaska Electric Light and Power Company	AVA	63.01%	62.52%	60.89%	60.49%	60.15%	62.14%	61.42%
Avista Corporation	AVA	49.96%	49.74%	50.65%	50.35%	50.57%	50.12%	50.26%
CenterPoint Energy Houston Electric, LLC	CNP	44.52%	44.46%	44.55%	42.04%	41.98%	44.51%	43.51%
Southern Indiana Gas and Electric Company	CNP	55.93%	55.66%	56.48%	56.38%	56.63%	56.02%	56.22%
Consumers Energy Company	CMS	48.71%	49.10%	49.78%	52.28%	51.17%	49.19%	50.21%
Consolidated Edison Company of New York, Inc.	ED	45.86%	47.44%	46.75%	46.82%	46.74%	46.68%	46.72%
Orange and Rockland Utilities, Inc.	ED	47.75%	48.57%	46.44%	47.69%	47.29%	47.59%	47.55%
Dominion Energy South Carolina, Inc.	D	53.14%	52.63%	54.80%	53.94%	56.18%	53.52%	54.14%
Virginia Electric and Power Company	D	53.46%	55.63%	51.62%	52.80%	52.36%	53.57%	53.17%
DTE Electric Company	DTE	49.79%	49.72%	50.41%	49.83%	49.45%	49.97%	49.84%
Duke Energy Carolinas, LLC	DUK	51.08%	52.00%	52.78%	52.05%	52.33%	51.95%	52.05%
Duke Energy Florida, LLC	DUK	53.67%	51.31%	50.74%	52.65%	52.59%	51.91%	52.19%
Duke Energy Indiana, LLC	DUK	53.41%	52.55%	52.06%	53.56%	53.74%	52.67%	53.06%
Duke Energy Kentucky, Inc.	DUK	54.31%	61.54%	52.97%	52.90%	49.54%	56.27%	54.25%
Duke Energy Ohio, Inc.	DUK	62.72%	64.39%	65.87%	64.40%	62.46%	64.32%	63.97%
Duke Energy Progress, LLC	DUK	51.71%	50.72%	51.27%	51.76%	50.69%	51.23%	51.23%
Entergy Arkansas, LLC	ETR	47.15%	45.08%	47.95%	47.84%	45.94%	46.73%	46.79%
Entergy Louisiana, LLC	ETR	54.22%	55.45%	47.17%	43.08%	45.62%	52.28%	49.11%
Entergy Mississippi, LLC	ETR	49.50%	49.32%	46.43%	45.53%	48.19%	48.42%	47.79%
Entergy New Orleans, LLC	ETR	48.50%	54.37%	47.94%	45.52%	50.04%	50.27%	49.27%
Entergy Texas, Inc.	ETR	49.74%	50.74%	49.99%	51.32%	47.05%	50.16%	49.77%
NSTAR Electric Company	ES	57.43%	57.61%	56.13%	55.37%	55.24%	57.06%	56.36%
Public Service Company of New Hampshire	ES	56.37%	56.16%	53.77%	49.10%	48.66%	55.43%	52.81%
The Connecticut Light and Power Company	ES	56.06%	56.77%	57.70%	55.53%	56.14%	56.84%	56.44%
Evergy Kansas Central, Inc.	EVRG	66.78%	65.11%	67.13%	67.00%	65.93%	66.34%	66.39%
Evergy Metro, Inc.	EVRG	50.97%	52.00%	52.03%	51.36%	48.69%	51.67%	51.01%
Evergy Missouri West, Inc.	EVRG	52.08%	56.02%	54.41%	52.01%	51.97%	54.17%	53.30%
Westar Energy (KPL)	EVRG	57.12%	55.18%	58.03%	58.52%	57.03%	56.78%	57.18%
Atlantic City Electric Company	EXC	50.02%	49.85%	50.08%	50.04%	49.90%	49.98%	49.98%
Baltimore Gas and Electric Company	EXC	51.98%	54.21%	53.81%	53.40%	53.22%	53.33%	53.32%
Commonwealth Edison Company	EXC	54.70%	54.95%	55.29%	55.13%	55.03%	54.98%	55.02%
Delmarva Power & Light Company	EXC	50.28%	50.22%	50.33%	49.68%	50.05%	50.28%	50.11%
PECO Energy Company	EXC	53.46%	53.10%	53.50%	53.66%	53.35%	53.35%	53.41%
Potomac Electric Power Company	EXC	50.19%	50.10%	50.03%	50.10%	50.12%	50.11%	50.11%
Jersey Central Power & Light Company	FE	67.97%	65.79%	64.86%	64.52%	69.18%	66.21%	66.46%
FirstEnergy Pennsylvania Electric Company	FE	52.71%	N/A	N/A	N/A	N/A	52.71%	52.71%
Metropolitan Edison Company	FE	N/A	49.86%	51.85%	50.96%	49.22%	50.86%	50.47%
Monongahela Power Company	FE	53.58%	45.09%	49.23%	45.10%	46.68%	49.30%	47.94%
Ohio Edison Company	FE	54.89%	57.90%	57.49%	68.75%	72.77%	56.76%	62.36%
Pennsylvania Electric Company	FE	N/A	46.24%	50.97%	50.42%	51.10%	48.61%	49.68%
Pennsylvania Power Company	FE	N/A	53.60%	49.28%	51.00%	49.90%	51.44%	50.94%
The Cleveland Electric Illuminating Company	FE	67.19%	55.54%	55.10%	51.41%	51.47%	59.28%	56.14%
The Potomac Edison Company	FE	51.72%	49.65%	53.39%	51.43%	48.53%	51.59%	50.94%
The Toledo Edison Company	FE	55.44%	54.67%	57.09%	55.02%	64.86%	55.74%	57.42%
West Penn Power Company	FE	N/A	50.03%	48.80%	49.39%	48.55%	49.41%	49.19%
Idaho Power Company	IDA	49.95%	49.42%	54.37%	55.00%	53.96%	51.24%	52.54%
Florida Power & Light Company	NEE	59.98%	58.67%	63.14%	62.12%	60.04%	60.60%	60.79%
Oklahoma Gas and Electric Company	OGE	53.25%	53.53%	55.65%	53.38%	53.04%	54.14%	53.77%
Arizona Public Service Company	PNW	52.22%	49.56%	50.25%	51.12%	51.35%	50.68%	50.90%
Portland General Electric Company	POR	45.57%	45.37%	43.24%	45.09%	46.07%	44.73%	45.07%
Public Service Electric and Gas Company	PEG	55.03%	55.40%	55.16%	55.17%	54.54%	55.20%	55.06%
Alabama Power Company	SO	53.88%	52.36%	52.22%	52.36%	52.37%	52.82%	52.64%
Georgia Power Company	SO	56.53%	56.32%	56.05%	55.60%	56.05%	56.30%	56.11%
Mississippi Power Company	SO	55.31%	55.01%	55.67%	55.40%	55.31%	55.33%	55.34%
Northern States Power Company - Minnesota	XEL	53.37%	52.58%	52.79%	52.65%	53.19%	52.91%	52.91%
Northern States Power Company - Wisconsin	XEL	53.23%	52.77%	53.45%	52.53%	53.85%	53.15%	53.17%
Public Service Company of Colorado	XEL	55.21%	56.47%	57.18%	56.44%	56.82%	56.29%	56.42%
Southwestern Public Service Company	XEL	54.17%	54.41%	54.30%	54.23%	54.17%	54.29%	54.25%
Operating Company								
MEAN		52.94%	52.52%	52.71%	52.38%	52.54%	52.67%	52.59%
MEDIAN		52.99%	52.18%	52.38%	52.17%	52.33%	51.95%	52.54%
LOW		43.47%	39.99%	42.07%	42.04%	41.98%	43.67%	43.29%
HIGH		67.97%	65.79%	67.13%	68.75%	72.77%	66.34%	66.46%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Evergy Kansas South was removed because it is financed with more than 80% common equity. Rockland Electric was removed because it is financed with 100% common equity.

Capital Structure Analysis

LONG-TERM DEBT RATIO [1]								
Proxy Group Company	Ticker	2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Alliant Energy Corporation	LNT	47.29%	47.90%	47.40%	48.68%	47.49%	47.53%	47.75%
Ameren Corporation	AEE	46.48%	46.06%	46.34%	46.28%	46.91%	46.30%	46.42%
American Electric Power Company, Inc.	AEP	51.42%	51.55%	51.44%	52.24%	51.85%	51.47%	51.70%
Avista Corporation	AVA	49.55%	49.76%	48.94%	49.21%	49.01%	49.42%	49.29%
CenterPoint Energy, Inc.	CNP	53.77%	53.80%	53.27%	55.11%	54.92%	53.61%	54.17%
CMS Energy Corporation	CMS	51.29%	50.90%	50.22%	47.72%	48.83%	50.81%	49.79%
Consolidated Edison, Inc.	ED	54.05%	52.50%	53.27%	53.13%	53.23%	53.27%	53.24%
Dominion Energy, Inc.	D	46.60%	44.92%	47.75%	46.96%	46.84%	46.42%	46.61%
DTE Energy Company	DTE	50.21%	50.28%	49.59%	50.17%	50.55%	50.03%	50.16%
Duke Energy Corporation	DUK	46.92%	47.13%	46.96%	46.61%	47.05%	47.00%	46.93%
Entergy Corporation	ETR	48.70%	48.04%	52.35%	54.52%	53.68%	49.70%	51.46%
Eversource Energy	ES	43.31%	42.98%	43.55%	45.50%	45.39%	43.28%	44.15%
Exelon Corporation	EXC	47.11%	46.73%	46.58%	46.70%	46.81%	46.81%	46.79%
FirstEnergy Corporation	FE	41.06%	45.81%	44.48%	44.76%	43.02%	43.78%	43.82%
Eergy, Inc.	EVRG	40.57%	41.16%	39.80%	39.96%	41.34%	40.51%	40.57%
IDACORP, Inc.	IDA	50.05%	50.58%	45.63%	45.00%	46.04%	48.76%	47.46%
NextEra Energy, Inc.	NEE	40.02%	41.33%	36.86%	37.88%	39.96%	39.40%	39.21%
OGE Energy Corporation	OGE	46.75%	46.47%	44.35%	46.62%	46.96%	45.86%	46.23%
Pinnacle West Capital Corporation	PNW	47.78%	50.44%	49.75%	48.88%	48.65%	49.32%	49.10%
Portland General Electric Company	POR	54.43%	54.63%	56.76%	54.91%	53.93%	55.27%	54.93%
Public Service Enterprise Group Inc.	PEG	44.97%	44.60%	44.84%	44.83%	45.46%	44.80%	44.94%
Southern Company	SO	44.46%	45.18%	45.42%	45.62%	45.34%	45.02%	45.20%
Xcel Energy Inc.	XEL	45.76%	45.53%	45.16%	45.59%	45.18%	45.48%	45.44%
Proxy Group								
MEAN		47.50%	47.75%	47.42%	47.69%	47.76%	47.56%	47.62%
MEDIAN		47.11%	47.13%	46.96%	46.70%	46.96%	47.00%	46.93%
LOW		40.02%	41.16%	36.86%	37.88%	39.96%	39.40%	39.21%
HIGH		54.43%	54.63%	56.76%	55.11%	54.92%	55.27%	54.93%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]								
Company Name	Ticker	2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Interstate Power and Light Company	LNT	48.27%	50.26%	49.45%	49.78%	47.66%	49.33%	49.09%
Wisconsin Power and Light Company	LNT	46.18%	45.23%	44.97%	47.14%	47.22%	45.46%	46.15%
Ameren Illinois Company	AEE	44.64%	43.79%	44.37%	44.22%	44.82%	44.27%	44.37%
Union Electric Company	AEE	48.08%	48.13%	48.12%	48.13%	48.78%	48.11%	48.25%
AEP Texas, Inc.	AEP	56.53%	54.31%	57.93%	57.19%	57.59%	56.26%	56.71%
Appalachian Power Company	AEP	49.74%	51.56%	52.24%	51.66%	52.81%	51.18%	51.60%
Indiana Michigan Power Company	AEP	49.82%	51.68%	50.71%	52.62%	51.33%	50.74%	51.23%
Kentucky Power Company	AEP	55.07%	57.74%	56.18%	55.83%	54.72%	56.33%	55.91%
Kingsport Power Company	AEP	47.01%	48.88%	46.11%	45.82%	46.58%	47.33%	46.88%
Ohio Power Company	AEP	49.05%	48.70%	49.21%	51.24%	47.58%	48.99%	49.16%
Public Service Company of Oklahoma	AEP	51.68%	48.25%	44.30%	45.64%	47.12%	48.08%	47.40%
Southwestern Electric Power Company	AEP	48.45%	49.32%	47.46%	51.30%	49.22%	48.41%	49.15%
Wheeling Power Company	AEP	55.34%	60.01%	50.86%	45.99%	45.90%	55.40%	51.62%
Alaska Electric Light and Power Company	AVA	36.99%	37.48%	39.11%	39.51%	39.85%	37.86%	38.58%
Avista Corporation	AVA	50.04%	50.26%	49.35%	49.65%	49.43%	49.88%	49.74%
CenterPoint Energy Houston Electric, LLC	CNP	55.48%	55.54%	55.45%	57.96%	58.02%	55.49%	56.49%
Southern Indiana Gas and Electric Company	CNP	44.07%	44.34%	43.52%	43.62%	43.37%	43.98%	43.78%
Consumers Energy Company	CMS	51.29%	50.90%	50.22%	47.72%	48.83%	50.81%	49.79%
Consolidated Edison Company of New York, Inc.	ED	54.14%	52.56%	53.25%	53.18%	53.26%	53.32%	53.28%
Orange and Rockland Utilities, Inc.	ED	52.25%	51.43%	53.56%	52.31%	52.71%	52.41%	52.45%
Dominion Energy South Carolina, Inc.	D	46.86%	47.37%	45.20%	46.06%	43.82%	46.48%	45.86%
Virginia Electric and Power Company	D	46.54%	44.37%	48.38%	47.20%	47.64%	46.43%	46.83%
DTE Electric Company	DTE	50.21%	50.28%	49.59%	50.17%	50.55%	50.03%	50.16%
Duke Energy Carolinas, LLC	DUK	48.92%	48.00%	47.22%	47.95%	47.67%	48.05%	47.95%
Duke Energy Florida, LLC	DUK	46.33%	48.69%	49.26%	47.35%	47.41%	48.09%	47.81%
Duke Energy Indiana, LLC	DUK	46.59%	47.45%	47.94%	46.44%	46.26%	47.33%	46.94%
Duke Energy Kentucky, Inc.	DUK	45.69%	38.46%	47.03%	47.10%	50.46%	43.73%	45.75%
Duke Energy Ohio, Inc.	DUK	37.28%	35.61%	34.13%	35.60%	37.54%	35.68%	36.03%
Duke Energy Progress, LLC	DUK	48.29%	49.28%	48.73%	48.24%	49.31%	48.77%	48.77%
Entergy Arkansas, LLC	ETR	52.85%	54.92%	52.05%	52.16%	54.06%	53.27%	53.21%
Entergy Louisiana, LLC	ETR	45.78%	44.55%	52.83%	56.92%	54.38%	47.72%	50.89%
Entergy Mississippi, LLC	ETR	50.50%	50.68%	53.57%	54.47%	51.81%	51.58%	52.21%
Entergy New Orleans, LLC	ETR	51.50%	45.63%	52.06%	54.48%	49.96%	49.73%	50.73%
Entergy Texas, Inc.	ETR	50.26%	49.26%	50.01%	48.68%	52.95%	49.84%	50.23%
NSTAR Electric Company	ES	42.57%	42.39%	43.87%	44.63%	44.76%	42.94%	43.64%
Public Service Company of New Hampshire	ES	43.63%	43.84%	46.23%	50.90%	51.34%	44.57%	47.19%
The Connecticut Light and Power Company	ES	43.94%	43.23%	42.30%	44.47%	43.86%	43.16%	43.56%
Evergy Kansas Central, Inc.	EVRG	33.22%	34.89%	32.87%	33.00%	34.07%	33.66%	33.61%
Evergy Metro, Inc.	EVRG	49.03%	48.00%	47.97%	48.64%	51.31%	48.33%	48.99%
Evergy Missouri West, Inc.	EVRG	47.92%	43.98%	45.59%	47.99%	48.03%	45.83%	46.70%
Westar Energy (KPL)	EVRG	42.88%	44.82%	41.97%	41.48%	42.97%	43.22%	42.82%
Atlantic City Electric Company	EXC	49.98%	50.15%	49.92%	49.96%	50.10%	50.02%	50.02%
Baltimore Gas and Electric Company	EXC	48.02%	45.79%	46.19%	46.60%	46.78%	46.67%	46.68%
Commonwealth Edison Company	EXC	45.30%	45.05%	44.71%	44.87%	44.97%	45.02%	44.98%
Delmarva Power & Light Company	EXC	49.72%	49.78%	49.67%	50.32%	49.95%	49.72%	49.89%
PECO Energy Company	EXC	46.54%	46.90%	46.50%	46.34%	46.65%	46.65%	46.59%
Potomac Electric Power Company	EXC	49.81%	49.90%	49.97%	49.90%	49.88%	49.89%	49.89%
Jersey Central Power & Light Company	FE	32.03%	34.21%	35.14%	35.48%	30.82%	33.79%	33.54%
FirstEnergy Pennsylvania Electric Company	FE	47.29%	N/A	N/A	N/A	N/A	47.29%	47.29%
Metropolitan Edison Company	FE	N/A	50.14%	48.15%	49.04%	50.78%	49.14%	49.53%
Monongahela Power Company	FE	46.42%	54.91%	50.77%	54.90%	53.32%	50.70%	52.06%
Ohio Edison Company	FE	45.11%	42.10%	42.51%	31.25%	27.23%	43.24%	37.64%
Pennsylvania Electric Company	FE	N/A	53.76%	49.03%	49.58%	48.90%	51.39%	50.32%
Pennsylvania Power Company	FE	N/A	46.40%	50.72%	49.00%	50.10%	48.56%	49.06%
The Cleveland Electric Illuminating Company	FE	32.81%	44.46%	44.90%	48.59%	48.53%	40.72%	43.86%
The Potomac Edison Company	FE	48.28%	50.35%	46.61%	48.57%	51.47%	48.41%	49.06%
The Toledo Edison Company	FE	44.56%	45.33%	42.91%	44.98%	35.14%	44.26%	42.58%
West Penn Power Company	FE	N/A	49.97%	51.20%	50.61%	51.45%	50.59%	50.81%
Idaho Power Company	IDA	50.05%	50.58%	45.63%	45.00%	46.04%	48.76%	47.46%
Florida Power & Light Company	NEE	40.02%	41.33%	36.86%	37.88%	39.96%	39.40%	39.21%
Oklahoma Gas and Electric Company	OGE	46.75%	46.47%	44.35%	46.62%	46.96%	45.86%	46.23%
Arizona Public Service Company	PNW	47.78%	50.44%	49.75%	48.88%	48.65%	49.32%	49.10%
Portland General Electric Company	POR	54.43%	54.63%	56.76%	54.91%	53.93%	55.27%	54.93%
Public Service Electric and Gas Company	PEG	44.97%	44.60%	44.84%	44.83%	45.46%	44.80%	44.94%
Alabama Power Company	SO	46.12%	47.64%	47.78%	47.64%	47.63%	47.18%	47.36%
Georgia Power Company	SO	43.47%	43.68%	43.95%	44.40%	43.95%	43.70%	43.89%
Mississippi Power Company	SO	44.69%	44.99%	44.33%	44.60%	44.69%	44.67%	44.66%
Northern States Power Company - Minnesota	XEL	46.63%	47.42%	47.21%	47.35%	46.81%	47.09%	47.09%
Northern States Power Company - Wisconsin	XEL	46.77%	47.23%	46.55%	47.47%	46.15%	46.85%	46.83%
Public Service Company of Colorado	XEL	44.79%	43.53%	42.82%	43.56%	43.18%	43.71%	43.58%
Southwestern Public Service Company	XEL	45.83%	45.59%	45.70%	45.77%	45.83%	45.71%	45.75%
Operating Company								
MEAN		47.06%	47.48%	47.29%	47.62%	47.46%	47.33%	47.41%
MEDIAN		47.01%	47.82%	47.62%	47.83%	47.67%	48.05%	47.46%
LOW		32.03%	34.21%	32.87%	31.25%	27.23%	33.66%	33.54%
HIGH		56.53%	60.01%	57.93%	57.96%	58.02%	56.33%	56.71%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Evergy Kansas South was removed because it is financed with more than 80% common equity. Rockland Electric was removed because it is financed with 100% common equity.

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment (Breuning Proxy Group)
30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	\$2.84	\$100.90	2.81%	2.92%	8.50%	7.50%	6.50%	7.50%	9.41%	10.42%	11.43%
American Electric Power Company, Inc.	AEP	\$3.80	\$117.59	3.23%	3.35%	6.50%	8.50%	6.50%	7.17%	9.84%	10.51%	11.87%
CenterPoint Energy, Inc.	CNP	\$0.88	\$38.58	2.28%	2.37%	8.90%	8.75%	7.00%	8.22%	9.36%	10.59%	11.28%
CMS Energy Corporation	CMS	\$2.17	\$71.57	3.03%	3.15%	7.30%	7.50%	8.50%	7.77%	10.44%	10.92%	11.66%
Consolidated Edison, Inc.	ED	\$3.40	\$98.61	3.45%	3.55%	6.10%	6.20%	6.00%	6.10%	9.55%	9.65%	9.75%
Dominion Energy, Inc.	D	\$2.67	\$59.79	4.47%	4.63%	10.30%	6.25%	6.00%	7.52%	10.60%	12.15%	15.00%
DTE Energy Company	DTE	\$4.66	\$131.62	3.54%	3.65%	7.10%	7.38%	4.50%	6.33%	8.12%	9.98%	11.05%
Duke Energy Corporation	DUK	\$4.26	\$118.45	3.60%	3.71%	6.90%	6.80%	6.00%	6.57%	9.70%	10.28%	10.62%
Entergy Corporation	ETR	\$2.56	\$93.56	2.74%	2.85%	10.20%	10.80%	3.00%	8.00%	5.78%	10.85%	13.68%
Eversource Energy	ES	\$3.01	\$67.05	4.49%	4.62%	5.90%	5.92%	5.50%	5.77%	10.11%	10.39%	10.54%
Exelon Corporation	EXC	\$1.60	\$44.46	3.60%	3.71%	6.00%	6.00%	6.00%	6.00%	9.71%	9.71%	9.71%
FirstEnergy Corporation	FE	\$1.78	\$45.36	3.92%	4.05%	6.50%	7.70%	4.50%	6.23%	8.51%	10.28%	11.78%
NorthWestern Energy Group, Inc.	NWE	\$2.64	\$65.94	4.00%	4.12%	6.90%	6.19%	4.50%	5.86%	8.59%	9.98%	11.04%
PPL Corporation	PPL	\$1.09	\$34.97	3.12%	3.23%	7.30%	7.70%	7.50%	7.50%	10.53%	10.73%	10.94%
Public Service Enterprise Group Inc.	PEG	\$2.52	\$80.65	3.12%	3.24%	8.10%	7.30%	7.00%	7.47%	10.23%	10.71%	11.35%
Xcel Energy Inc.	XEL	\$2.28	\$76.64	2.97%	3.10%	8.90%	8.88%	7.00%	8.26%	10.08%	11.36%	12.01%
Proxy Group Mean				3.40%	3.52%	7.59%	7.46%	6.00%	7.02%	9.41%	10.53%	11.48%
Proxy Group Median				3.34%	3.45%	7.20%	7.44%	6.00%	7.32%	9.71%	10.47%	11.32%
Average of Mean and Median				3.37%	3.48%	7.39%	7.45%	6.00%	7.17%	9.56%	10.50%	11.40%

Notes:

- [1] Source: S&P Capital IQ
- [2] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025
- [3] Equals [1] / [2]
- [4] Equals [3] x (1 + 0.5 x [8])
- [5] Source: Zacks
- [6] Source: S&P Capital IQ
- [7] Source: Value Line
- [8] Equals Average ([5], [6], [7])
- [9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
- [10] Equals [4] + [8]
- [11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment (Breuning Proxy Group)
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	\$2.84	\$101.92	2.79%	2.89%	8.50%	7.50%	6.50%	7.50%	9.38%	10.39%	11.40%
American Electric Power Company, Inc.	AEP	\$3.80	\$115.55	3.29%	3.41%	6.50%	8.50%	6.50%	7.17%	9.90%	10.57%	11.93%
CenterPoint Energy, Inc.	CNP	\$0.88	\$38.71	2.27%	2.37%	8.90%	8.75%	7.00%	8.22%	9.35%	10.58%	11.27%
CMS Energy Corporation	CMS	\$2.17	\$72.34	3.00%	3.12%	7.30%	7.50%	8.50%	7.77%	10.41%	10.88%	11.63%
Consolidated Edison, Inc.	ED	\$3.40	\$98.87	3.44%	3.54%	6.10%	6.20%	6.00%	6.10%	9.54%	9.64%	9.75%
Dominion Energy, Inc.	D	\$2.67	\$60.11	4.44%	4.61%	10.30%	6.25%	6.00%	7.52%	10.57%	12.13%	14.97%
DTE Energy Company	DTE	\$4.66	\$136.12	3.42%	3.53%	7.10%	7.38%	4.50%	6.33%	8.00%	9.86%	10.93%
Duke Energy Corporation	DUK	\$4.26	\$122.07	3.49%	3.60%	6.90%	6.80%	6.00%	6.57%	9.59%	10.17%	10.51%
Entergy Corporation	ETR	\$2.56	\$93.25	2.75%	2.86%	10.20%	10.80%	3.00%	8.00%	5.79%	10.86%	13.69%
Eversource Energy	ES	\$3.01	\$68.88	4.37%	4.50%	5.90%	5.92%	5.50%	5.77%	9.99%	10.27%	10.42%
Exelon Corporation	EXC	\$1.60	\$45.07	3.55%	3.66%	6.00%	6.00%	6.00%	6.00%	9.66%	9.66%	9.66%
FirstEnergy Corporation	FE	\$1.78	\$45.30	3.93%	4.05%	6.50%	7.70%	4.50%	6.23%	8.52%	10.29%	11.78%
NorthWestern Energy Group, Inc.	NWE	\$2.64	\$61.54	4.29%	4.42%	6.90%	6.19%	4.50%	5.86%	8.89%	10.28%	11.34%
PPL Corporation	PPL	\$1.09	\$36.10	3.02%	3.13%	7.30%	7.70%	7.50%	7.50%	10.43%	10.63%	10.84%
Public Service Enterprise Group Inc.	PEG	\$2.52	\$81.67	3.09%	3.20%	8.10%	7.30%	7.00%	7.47%	10.19%	10.67%	11.31%
Xcel Energy Inc.	XEL	\$2.28	\$77.38	2.95%	3.07%	8.90%	8.88%	7.00%	8.26%	10.05%	11.33%	11.98%
Proxy Group Mean				3.38%	3.50%	7.59%	7.46%	6.00%	7.02%	9.39%	10.51%	11.46%
Proxy Group Median				3.36%	3.47%	7.20%	7.44%	6.00%	7.32%	9.63%	10.48%	11.32%
Average of Mean and Median				3.37%	3.48%	7.39%	7.45%	6.00%	7.17%	9.51%	10.50%	11.39%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [8])

[5] Source: Zacks

[6] Source: S&P Capital IQ

[7] Source: Value Line

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment (Breuning Proxy Group)
180 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	\$2.84	\$99.96	2.84%	2.95%	8.50%	7.50%	6.50%	7.50%	9.43%	10.45%	11.46%
American Electric Power Company, Inc.	AEP	\$3.80	\$110.90	3.43%	3.55%	6.50%	8.50%	6.50%	7.17%	10.04%	10.72%	12.07%
CenterPoint Energy, Inc.	CNP	\$0.88	\$38.03	2.31%	2.41%	8.90%	8.75%	7.00%	8.22%	9.39%	10.63%	11.32%
CMS Energy Corporation	CMS	\$2.17	\$71.90	3.02%	3.14%	7.30%	7.50%	8.50%	7.77%	10.43%	10.90%	11.65%
Consolidated Edison, Inc.	ED	\$3.40	\$101.38	3.35%	3.46%	6.10%	6.20%	6.00%	6.10%	9.45%	9.56%	9.66%
Dominion Energy, Inc.	D	\$2.67	\$58.47	4.57%	4.74%	10.30%	6.25%	6.00%	7.52%	10.70%	12.25%	15.10%
DTE Energy Company	DTE	\$4.66	\$135.95	3.43%	3.54%	7.10%	7.38%	4.50%	6.33%	8.00%	9.86%	10.93%
Duke Energy Corporation	DUK	\$4.26	\$120.60	3.53%	3.65%	6.90%	6.80%	6.00%	6.57%	9.64%	10.22%	10.55%
Entergy Corporation	ETR	\$2.56	\$88.89	2.88%	3.00%	10.20%	10.80%	3.00%	8.00%	5.92%	11.00%	13.84%
Eversource Energy	ES	\$3.01	\$66.27	4.54%	4.67%	5.90%	5.92%	5.50%	5.77%	10.17%	10.44%	10.59%
Exelon Corporation	EXC	\$1.60	\$44.65	3.58%	3.69%	6.00%	6.00%	6.00%	6.00%	9.69%	9.69%	9.69%
FirstEnergy Corporation	FE	\$1.78	\$43.50	4.09%	4.22%	6.50%	7.70%	4.50%	6.23%	8.68%	10.45%	11.95%
NorthWestern Energy Group, Inc.	NWE	\$2.64	\$58.03	4.55%	4.68%	6.90%	6.19%	4.50%	5.86%	9.15%	10.54%	11.61%
PPL Corporation	PPL	\$1.09	\$35.65	3.06%	3.17%	7.30%	7.70%	7.50%	7.50%	10.47%	10.67%	10.88%
Public Service Enterprise Group Inc.	PEG	\$2.52	\$82.11	3.07%	3.18%	8.10%	7.30%	7.00%	7.47%	10.18%	10.65%	11.29%
Xcel Energy Inc.	XEL	\$2.28	\$73.80	3.09%	3.22%	8.90%	8.88%	7.00%	8.26%	10.20%	11.48%	12.13%
Proxy Group Mean				3.46%	3.58%	7.59%	7.46%	6.00%	7.02%	9.47%	10.59%	11.54%
Proxy Group Median				3.39%	3.50%	7.20%	7.44%	6.00%	7.32%	9.66%	10.59%	11.39%
Average of Mean and Median				3.42%	3.54%	7.39%	7.45%	6.00%	7.17%	9.57%	10.59%	11.47%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[3] Equals [1] / [2]

[4] Equals [3] x (1 + 0.5 x [8])

[5] Source: Zacks

[6] Source: S&P Capital IQ

[7] Source: Value Line

[8] Equals Average ([5], [6], [7])

[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])

[10] Equals [4] + [8]

[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Growth Discounted Cash Flow Model (Breuning Proxy Group)
30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	\$0.71	\$0.71	\$0.71	\$0.71	\$0.76	\$0.76	\$0.76	\$0.76	\$100.90	8.50%	7.50%	6.50%	7.50%	9.60%	10.64%	11.68%
American Electric Power Company, Inc.	AEP	\$0.93	\$0.93	\$0.93	\$0.95	\$1.00	\$1.00	\$1.00	\$1.02	\$117.59	6.50%	8.50%	6.50%	7.17%	10.01%	10.71%	12.10%
CenterPoint Energy, Inc.	CNP	\$0.22	\$0.22	\$0.22	\$0.22	\$0.24	\$0.24	\$0.24	\$0.24	\$38.58	8.90%	8.75%	7.00%	8.22%	9.53%	10.78%	11.49%
CMS Energy Corporation	CMS	\$0.54	\$0.54	\$0.54	\$0.54	\$0.58	\$0.58	\$0.58	\$0.58	\$71.57	7.30%	7.50%	8.50%	7.77%	10.68%	11.17%	11.93%
Consolidated Edison, Inc.	ED	\$0.85	\$0.85	\$0.85	\$0.85	\$0.90	\$0.90	\$0.90	\$0.90	\$98.61	6.10%	6.20%	6.00%	6.10%	9.79%	9.89%	10.00%
Dominion Energy, Inc.	D	\$0.67	\$0.67	\$0.67	\$0.67	\$0.72	\$0.72	\$0.72	\$0.72	\$59.79	10.30%	6.25%	6.00%	7.52%	10.92%	12.54%	15.50%
DTE Energy Company	DTE	\$1.09	\$1.09	\$1.09	\$1.17	\$1.16	\$1.16	\$1.16	\$1.24	\$131.62	7.10%	7.38%	4.50%	6.33%	8.12%	10.04%	11.14%
Duke Energy Corporation	DUK	\$1.05	\$1.05	\$1.07	\$1.07	\$1.11	\$1.11	\$1.13	\$1.13	\$118.45	6.90%	6.80%	6.00%	6.57%	9.91%	10.51%	10.86%
Entergy Corporation	ETR	\$0.60	\$0.60	\$0.60	\$0.64	\$0.65	\$0.65	\$0.65	\$0.69	\$93.56	10.20%	10.80%	3.00%	8.00%	5.74%	10.93%	13.83%
Eversource Energy	ES	\$0.75	\$0.75	\$0.75	\$0.75	\$0.80	\$0.80	\$0.80	\$0.80	\$67.05	5.90%	5.92%	5.50%	5.77%	10.42%	10.71%	10.86%
Exelon Corporation	EXC	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$0.42	\$0.42	\$0.42	\$44.46	6.00%	6.00%	6.00%	6.00%	9.95%	9.95%	9.95%
FirstEnergy Corporation	FE	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$45.36	6.50%	7.70%	4.50%	6.23%	8.68%	10.51%	12.06%
NorthWestern Energy Group, Inc.	NWE	\$0.66	\$0.66	\$0.66	\$0.66	\$0.70	\$0.70	\$0.70	\$0.70	\$65.94	6.90%	6.19%	4.50%	5.86%	8.82%	10.26%	11.36%
PPL Corporation	PPL	\$0.27	\$0.27	\$0.27	\$0.27	\$0.29	\$0.29	\$0.29	\$0.29	\$34.97	7.30%	7.70%	7.50%	7.50%	10.78%	10.99%	11.19%
Public Service Enterprise Group Inc.	PEG	\$0.63	\$0.63	\$0.63	\$0.63	\$0.68	\$0.68	\$0.68	\$0.68	\$80.65	8.10%	7.30%	7.00%	7.47%	10.47%	10.96%	11.62%
Xcel Energy Inc.	XEL	\$0.57	\$0.57	\$0.57	\$0.57	\$0.62	\$0.62	\$0.62	\$0.62	\$76.64	8.90%	8.88%	7.00%	8.26%	10.30%	11.62%	12.29%
Proxy Group Mean											7.59%	7.46%	6.00%	7.02%	9.61%	10.76%	11.74%
Proxy Group Median											7.20%	7.44%	6.00%	7.32%	9.93%	10.71%	11.56%
Average of Mean and Median															9.77%	10.74%	11.65%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ

[3] Source: S&P Capital IQ

[4] Source: S&P Capital IQ

[5] Equals Col. [1] x (1 + Col. [13])

[6] Equals Col. [2] x (1 + Col. [13])

[7] Equals Col. [3] x (1 + Col. [13])

[8] Equals Col. [4] x (1 + Col. [13])

[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[10] Source: Zacks

[11] Source: S&P Capital IQ

[12] Source: Value Line

[13] Equals Average (Cols. [10], [11], [12])

[14] Implied Low DCF

[15] Implied Mean DCF

[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model (Breuning Proxy Group)
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	\$0.71	\$0.71	\$0.71	\$0.71	\$0.76	\$0.76	\$0.76	\$0.76	\$101.92	8.50%	7.50%	6.50%	7.50%	9.57%	10.61%	11.65%
American Electric Power Company, Inc.	AEP	\$0.93	\$0.93	\$0.93	\$0.95	\$1.00	\$1.00	\$1.00	\$1.02	\$115.55	6.50%	8.50%	6.50%	7.17%	10.07%	10.77%	12.17%
CenterPoint Energy, Inc.	CNP	\$0.22	\$0.22	\$0.22	\$0.22	\$0.24	\$0.24	\$0.24	\$0.24	\$38.71	8.90%	8.75%	7.00%	8.22%	9.52%	10.77%	11.48%
CMS Energy Corporation	CMS	\$0.54	\$0.54	\$0.54	\$0.54	\$0.58	\$0.58	\$0.58	\$0.58	\$72.34	7.30%	7.50%	8.50%	7.77%	10.64%	11.13%	11.90%
Consolidated Edison, Inc.	ED	\$0.85	\$0.85	\$0.85	\$0.85	\$0.90	\$0.90	\$0.90	\$0.90	\$98.87	6.10%	6.20%	6.00%	6.10%	9.78%	9.88%	9.99%
Dominion Energy, Inc.	D	\$0.67	\$0.67	\$0.67	\$0.67	\$0.72	\$0.72	\$0.72	\$0.72	\$60.11	10.30%	6.25%	6.00%	7.52%	10.90%	12.51%	15.47%
DTE Energy Company	DTE	\$1.09	\$1.09	\$1.09	\$1.17	\$1.16	\$1.16	\$1.16	\$1.24	\$136.12	7.10%	7.38%	4.50%	6.33%	8.00%	9.92%	11.02%
Duke Energy Corporation	DUK	\$1.05	\$1.05	\$1.07	\$1.07	\$1.11	\$1.11	\$1.13	\$1.13	\$122.07	6.90%	6.80%	6.00%	6.57%	9.80%	10.39%	10.74%
Entergy Corporation	ETR	\$0.60	\$0.60	\$0.60	\$0.64	\$0.65	\$0.65	\$0.65	\$0.69	\$93.25	10.20%	10.80%	3.00%	8.00%	5.75%	10.94%	13.84%
Eversource Energy	ES	\$0.75	\$0.75	\$0.75	\$0.75	\$0.80	\$0.80	\$0.80	\$0.80	\$68.88	5.90%	5.92%	5.50%	5.77%	10.28%	10.57%	10.73%
Exelon Corporation	EXC	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$0.42	\$0.42	\$0.42	\$45.07	6.00%	6.00%	6.00%	6.00%	9.90%	9.90%	9.90%
FirstEnergy Corporation	FE	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$45.30	6.50%	7.70%	4.50%	6.23%	8.69%	10.52%	12.07%
NorthWestern Energy Group, Inc.	NWE	\$0.66	\$0.66	\$0.66	\$0.66	\$0.70	\$0.70	\$0.70	\$0.70	\$61.54	6.90%	6.19%	4.50%	5.86%	9.13%	10.58%	11.68%
PPL Corporation	PPL	\$0.27	\$0.27	\$0.27	\$0.27	\$0.29	\$0.29	\$0.29	\$0.29	\$36.10	7.30%	7.70%	7.50%	7.50%	10.67%	10.88%	11.08%
Public Service Enterprise Group Inc.	PEG	\$0.63	\$0.63	\$0.63	\$0.63	\$0.68	\$0.68	\$0.68	\$0.68	\$81.67	8.10%	7.30%	7.00%	7.47%	10.43%	10.92%	11.58%
Xcel Energy Inc.	XEL	\$0.57	\$0.57	\$0.57	\$0.57	\$0.62	\$0.62	\$0.62	\$0.62	\$77.38	8.90%	8.88%	7.00%	8.26%	10.27%	11.58%	12.25%
Proxy Group Mean											7.59%	7.46%	6.00%	7.02%	9.59%	10.74%	11.72%
Proxy Group Median											7.20%	7.44%	6.00%	7.32%	9.85%	10.69%	11.61%
Average of Mean and Median															9.72%	10.72%	11.67%

Notes:

- [1] Source: S&P Capital IQ
- [2] Source: S&P Capital IQ
- [3] Source: S&P Capital IQ
- [4] Source: S&P Capital IQ
- [5] Equals Col. [1] x (1 + Col. [13])
- [6] Equals Col. [2] x (1 + Col. [13])
- [7] Equals Col. [3] x (1 + Col. [13])
- [8] Equals Col. [4] x (1 + Col. [13])
- [9] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025
- [10] Source: Zacks
- [11] Source: S&P Capital IQ
- [12] Source: Value Line
- [13] Equals Average (Cols. [10], [11], [12])
- [14] Implied Low DCF
- [15] Implied Mean DCF
- [16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model (Breuning Proxy Group)
180 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Dividend 1	Dividend 2	Dividend 3	Dividend 4	Expected Dividend 1	Expected Dividend 2	Expected Dividend 3	Expected Dividend 4	Average Stock Price	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
Ameren Corporation	AEE	\$0.71	\$0.71	\$0.71	\$0.71	\$0.76	\$0.76	\$0.76	\$0.76	\$99.96	8.50%	7.50%	6.50%	7.50%	9.63%	10.67%	11.72%
American Electric Power Company, Inc.	AEP	\$0.93	\$0.93	\$0.93	\$0.95	\$1.00	\$1.00	\$1.00	\$1.02	\$110.90	6.50%	8.50%	6.50%	7.17%	10.23%	10.92%	12.32%
CenterPoint Energy, Inc.	CNP	\$0.22	\$0.22	\$0.22	\$0.22	\$0.24	\$0.24	\$0.24	\$0.24	\$38.03	8.90%	8.75%	7.00%	8.22%	9.56%	10.82%	11.53%
CMS Energy Corporation	CMS	\$0.54	\$0.54	\$0.54	\$0.54	\$0.58	\$0.58	\$0.58	\$0.58	\$71.90	7.30%	7.50%	8.50%	7.77%	10.67%	11.15%	11.92%
Consolidated Edison, Inc.	ED	\$0.85	\$0.85	\$0.85	\$0.85	\$0.90	\$0.90	\$0.90	\$0.90	\$101.38	6.10%	6.20%	6.00%	6.10%	9.68%	9.79%	9.89%
Dominion Energy, Inc.	D	\$0.67	\$0.67	\$0.67	\$0.67	\$0.72	\$0.72	\$0.72	\$0.72	\$58.47	10.30%	6.25%	6.00%	7.52%	11.04%	12.65%	15.62%
DTE Energy Company	DTE	\$1.09	\$1.09	\$1.09	\$1.17	\$1.16	\$1.16	\$1.16	\$1.24	\$135.95	7.10%	7.38%	4.50%	6.33%	8.01%	9.92%	11.02%
Duke Energy Corporation	DUK	\$1.05	\$1.05	\$1.07	\$1.07	\$1.11	\$1.11	\$1.13	\$1.13	\$120.60	6.90%	6.80%	6.00%	6.57%	9.84%	10.44%	10.79%
Entergy Corporation	ETR	\$0.60	\$0.60	\$0.60	\$0.64	\$0.65	\$0.65	\$0.65	\$0.69	\$88.89	10.20%	10.80%	3.00%	8.00%	5.89%	11.08%	13.99%
Eversource Energy	ES	\$0.75	\$0.75	\$0.75	\$0.75	\$0.80	\$0.80	\$0.80	\$0.80	\$66.27	5.90%	5.92%	5.50%	5.77%	10.48%	10.77%	10.92%
Exelon Corporation	EXC	\$0.40	\$0.40	\$0.40	\$0.40	\$0.42	\$0.42	\$0.42	\$0.42	\$44.65	6.00%	6.00%	6.00%	6.00%	9.94%	9.94%	9.94%
FirstEnergy Corporation	FE	\$0.43	\$0.45	\$0.45	\$0.45	\$0.45	\$0.47	\$0.47	\$0.47	\$43.50	6.50%	7.70%	4.50%	6.23%	8.86%	10.70%	12.25%
NorthWestern Energy Group, Inc.	NWE	\$0.66	\$0.66	\$0.66	\$0.66	\$0.70	\$0.70	\$0.70	\$0.70	\$58.03	6.90%	6.19%	4.50%	5.86%	9.42%	10.87%	11.98%
PPL Corporation	PPL	\$0.27	\$0.27	\$0.27	\$0.27	\$0.29	\$0.29	\$0.29	\$0.29	\$35.65	7.30%	7.70%	7.50%	7.50%	10.71%	10.92%	11.13%
Public Service Enterprise Group Inc.	PEG	\$0.63	\$0.63	\$0.63	\$0.63	\$0.68	\$0.68	\$0.68	\$0.68	\$82.11	8.10%	7.30%	7.00%	7.47%	10.41%	10.90%	11.56%
Xcel Energy Inc.	XEL	\$0.57	\$0.57	\$0.57	\$0.57	\$0.62	\$0.62	\$0.62	\$0.62	\$73.80	8.90%	8.88%	7.00%	8.26%	10.43%	11.75%	12.42%
Proxy Group Mean											7.59%	7.46%	6.00%	7.02%	9.67%	10.83%	11.81%
Proxy Group Median											7.20%	7.44%	6.00%	7.32%	9.89%	10.85%	11.64%
Average of Mean and Median															9.78%	10.84%	11.72%

Notes:

[1] Source: S&P Capital IQ

[2] Source: S&P Capital IQ

[3] Source: S&P Capital IQ

[4] Source: S&P Capital IQ

[5] Equals Col. [1] x (1 + Col. [13])

[6] Equals Col. [2] x (1 + Col. [13])

[7] Equals Col. [3] x (1 + Col. [13])

[8] Equals Col. [4] x (1 + Col. [13])

[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 12/31/2025

[10] Source: Zacks

[11] Source: S&P Capital IQ

[12] Source: Value Line

[13] Equals Average (Cols. [10], [11], [12])

[14] Implied Low DCF

[15] Implied Mean DCF

[16] Implied High DCF

Summary of CAPM and ECAPM Results (Breuning Proxy Group)

	Current 30-Year Treasury Yield (4.77%)	Projected 30-Year Treasury Yield (4.62%)
CAPM Forward Market Return	12.85%	12.84%
ECAPM Forward Market Return	13.63%	13.62%
Average Forward Market Return CAPM		13.24%
CAPM Historical Market Return	10.14%	10.10%
ECAPM Historical Market Return	10.65%	10.62%
Average Historical Market Return CAPM		10.38%

Source: Exhibit JEN-11R, pages 2-5

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results (Breunung Proxy Group)
Using DCF-derived Expected Market Return and 5-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Ameren Corporation	AEE	4.77%	0.63	0.80	0.71	15.95%	11.18%	12.77%	13.56%
American Electric Power Company, Inc.	AEP	4.77%	0.55	0.70	0.62	15.95%	11.18%	11.73%	12.79%
CenterPoint Energy, Inc.	CNP	4.77%	0.67	0.80	0.64	15.95%	11.18%	11.95%	12.95%
CMS Energy Corporation	CMS	4.77%	0.57	0.70	0.73	15.95%	11.18%	12.99%	13.73%
Consolidated Edison, Inc.	ED	4.77%	0.47	0.65	0.63	15.95%	11.18%	11.87%	12.89%
Dominion Energy, Inc.	D	4.77%	0.60	0.80	0.56	15.95%	11.18%	11.03%	12.26%
DTE Energy Company	DTE	4.77%	0.60	0.80	0.70	15.95%	11.18%	12.58%	13.42%
Duke Energy Corporation	DUK	4.77%	0.50	0.65	0.70	15.95%	11.18%	12.60%	13.44%
Entergy Corporation	ETR	4.77%	0.66	0.75	0.58	15.95%	11.18%	11.21%	12.40%
Eversource Energy	ES	4.77%	0.63	0.85	0.71	15.95%	11.18%	12.67%	13.49%
Exelon Corporation	EXC	4.77%	0.63	0.75	0.74	15.95%	11.18%	13.04%	13.77%
FirstEnergy Corporation	FE	4.77%	0.57	0.75	0.69	15.95%	11.18%	12.47%	13.34%
NorthWestern Energy Group, Inc.	NWE	4.77%	0.57	0.75	0.66	15.95%	11.18%	12.16%	13.11%
PPL Corporation	PPL	4.77%	0.63	0.80	0.68	15.95%	11.18%	12.35%	13.25%
Public Service Enterprise Group Inc.	PEG	4.77%	0.71	0.85	0.60	15.95%	11.18%	11.53%	12.63%
Xcel Energy Inc.	XEL	4.77%	0.58	0.70	0.84	15.95%	11.18%	14.13%	14.58%
								Mean:	12.32%
								Median:	12.41%
								Average of the Mean and Median:	12.36%
		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Ameren Corporation	AEE	4.62%	0.63	0.80	0.71	15.95%	11.34%	12.72%	13.53%
American Electric Power Company, Inc.	AEP	4.62%	0.55	0.70	0.62	15.95%	11.34%	11.67%	12.74%
CenterPoint Energy, Inc.	CNP	4.62%	0.67	0.80	0.73	15.95%	11.34%	12.95%	13.70%
CMS Energy Corporation	CMS	4.62%	0.57	0.70	0.63	15.95%	11.34%	11.81%	12.85%
Consolidated Edison, Inc.	ED	4.62%	0.47	0.65	0.56	15.95%	11.34%	10.96%	12.21%
Dominion Energy, Inc.	D	4.62%	0.60	0.80	0.70	15.95%	11.34%	12.53%	13.39%
DTE Energy Company	DTE	4.62%	0.60	0.80	0.70	15.95%	11.34%	12.55%	13.40%
Duke Energy Corporation	DUK	4.62%	0.50	0.65	0.58	15.95%	11.34%	11.15%	12.35%
Entergy Corporation	ETR	4.62%	0.66	0.75	0.71	15.95%	11.34%	12.63%	13.46%
Eversource Energy	ES	4.62%	0.63	0.85	0.74	15.95%	11.34%	13.00%	13.74%
Exelon Corporation	EXC	4.62%	0.63	0.75	0.69	15.95%	11.34%	12.42%	13.30%
FirstEnergy Corporation	FE	4.62%	0.57	0.75	0.66	15.95%	11.34%	12.11%	13.07%
NorthWestern Energy Group, Inc.	NWE	4.62%	0.57	0.75	0.66	15.95%	11.34%	12.11%	13.07%
PPL Corporation	PPL	4.62%	0.63	0.80	0.72	15.95%	11.34%	12.75%	13.55%
Public Service Enterprise Group Inc.	PEG	4.62%	0.71	0.85	0.78	15.95%	11.34%	13.44%	14.07%
Xcel Energy Inc.	XEL	4.62%	0.58	0.70	0.64	15.95%	11.34%	11.86%	12.88%
								Mean:	12.29%
								Median:	12.48%
								Average of the Mean and Median:	12.38%

Notes:

- [1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: JEN-3R; Value Line DCF-based expected market return
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results (Breuning Proxy Group)
Using DCF-derived Expected Market Return and 10-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Ameren Corporation	AEE	4.77%	0.72	15.95%	11.18%	12.86%	13.63%
American Electric Power Company, Inc.	AEP	4.77%	0.71	15.95%	11.18%	12.73%	13.53%
CenterPoint Energy, Inc.	CNP	4.77%	0.93	15.95%	11.18%	15.15%	15.35%
CMS Energy Corporation	CMS	4.77%	0.71	15.95%	11.18%	12.67%	13.49%
Consolidated Edison, Inc.	ED	4.77%	0.59	15.95%	11.18%	11.36%	12.51%
Dominion Energy, Inc.	D	4.77%	0.68	15.95%	11.18%	12.42%	13.30%
DTE Energy Company	DTE	4.77%	0.78	15.95%	11.18%	13.55%	14.15%
Duke Energy Corporation	DUK	4.77%	0.68	15.95%	11.18%	12.39%	13.28%
Entergy Corporation	ETR	4.77%	0.83	15.95%	11.18%	14.08%	14.55%
Eversource Energy	ES	4.77%	0.79	15.95%	11.18%	13.56%	14.16%
Exelon Corporation	EXC	4.77%	0.81	15.95%	11.18%	13.77%	14.32%
FirstEnergy Corporation	FE	4.77%	0.75	15.95%	11.18%	13.15%	13.85%
NorthWestern Energy Group, Inc.	NWE	4.77%	0.83	15.95%	11.18%	14.01%	14.50%
PPL Corporation	PPL	4.77%	0.90	15.95%	11.18%	14.79%	15.08%
Public Service Enterprise Group Inc.	PEG	4.77%	0.83	15.95%	11.18%	14.05%	14.53%
Xcel Energy Inc.	XEL	4.77%	0.72	15.95%	11.18%	12.79%	13.58%
						Mean:	13.33%
						Median:	13.35%
						Average of the Mean and Median:	13.34%
							13.99%
		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	DCF Expected Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Ameren Corporation	AEE	4.62%	0.72	15.95%	11.34%	12.81%	13.60%
American Electric Power Company, Inc.	AEP	4.62%	0.71	15.95%	11.34%	12.68%	13.50%
CenterPoint Energy, Inc.	CNP	4.62%	0.93	15.95%	11.34%	15.13%	15.34%
CMS Energy Corporation	CMS	4.62%	0.71	15.95%	11.34%	12.62%	13.46%
Consolidated Edison, Inc.	ED	4.62%	0.59	15.95%	11.34%	11.29%	12.46%
Dominion Energy, Inc.	D	4.62%	0.68	15.95%	11.34%	12.37%	13.26%
DTE Energy Company	DTE	4.62%	0.78	15.95%	11.34%	13.51%	14.12%
Duke Energy Corporation	DUK	4.62%	0.68	15.95%	11.34%	12.34%	13.24%
Entergy Corporation	ETR	4.62%	0.83	15.95%	11.34%	14.05%	14.53%
Eversource Energy	ES	4.62%	0.79	15.95%	11.34%	13.53%	14.14%
Exelon Corporation	EXC	4.62%	0.81	15.95%	11.34%	13.74%	14.30%
FirstEnergy Corporation	FE	4.62%	0.75	15.95%	11.34%	13.11%	13.82%
NorthWestern Energy Group, Inc.	NWE	4.62%	0.83	15.95%	11.34%	13.98%	14.48%
PPL Corporation	PPL	4.62%	0.90	15.95%	11.34%	14.78%	15.07%
Public Service Enterprise Group Inc.	PEG	4.62%	0.83	15.95%	11.34%	14.02%	14.51%
Xcel Energy Inc.	XEL	4.62%	0.72	15.95%	11.34%	12.75%	13.55%
						Mean:	13.30%
						Median:	13.31%
						Average of the Mean and Median:	13.30%
							13.96%

Notes:

[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average

[2] Source: Bloomberg Professional Service

[3] Source: JEN-3R; Value Line DCF-based expected market return

[4] Equals Col. [3] - Col. [1]

[5] Equals Col. [1] + (Col. [2] x Col. [4])

[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])

[7] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14

[8] See Note [2]

[9] See Note [3]

[10] Equals Col. [9] - Col. [7]

[11] Equals Col. [7] + (Col. [8] x Col. [10])

[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results (Breuning Proxy Group)
Using Long-Term Historical Market Return and 5-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Ameren Corporation	AEE	4.77%	0.63	0.80	0.71	12.17%	7.40%	10.06%	10.59%
American Electric Power Company, Inc.	AEP	4.77%	0.55	0.70	0.62	12.17%	7.40%	9.38%	10.08%
CenterPoint Energy, Inc.	CNP	4.77%	0.67	0.80	0.73	12.17%	7.40%	10.21%	10.70%
CMS Energy Corporation	CMS	4.77%	0.57	0.70	0.63	12.17%	7.40%	9.47%	10.14%
Consolidated Edison, Inc.	ED	4.77%	0.47	0.65	0.56	12.17%	7.40%	8.91%	9.73%
Dominion Energy, Inc.	D	4.77%	0.60	0.80	0.70	12.17%	7.40%	9.94%	10.50%
DTE Energy Company	DTE	4.77%	0.60	0.80	0.70	12.17%	7.40%	9.95%	10.51%
Duke Energy Corporation	DUK	4.77%	0.50	0.65	0.58	12.17%	7.40%	9.03%	9.82%
Entergy Corporation	ETR	4.77%	0.66	0.75	0.71	12.17%	7.40%	10.00%	10.54%
Eversource Energy	ES	4.77%	0.63	0.85	0.74	12.17%	7.40%	10.24%	10.73%
Exelon Corporation	EXC	4.77%	0.63	0.75	0.69	12.17%	7.40%	9.87%	10.44%
FirstEnergy Corporation	FE	4.77%	0.57	0.75	0.66	12.17%	7.40%	9.66%	10.29%
NorthWestern Energy Group, Inc.	NWE	4.77%	0.57	0.75	0.66	12.17%	7.40%	9.66%	10.29%
PPL Corporation	PPL	4.77%	0.63	0.80	0.72	12.17%	7.40%	10.08%	10.60%
Public Service Enterprise Group Inc.	PEG	4.77%	0.71	0.85	0.78	12.17%	7.40%	10.53%	10.94%
Xcel Energy Inc.	XEL	4.77%	0.58	0.70	0.64	12.17%	7.40%	9.50%	10.17%
								Mean:	9.78%
								Median:	9.90%
								Average of the Mean and Median:	9.84%
									10.42%
		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Ameren Corporation	AEE	4.62%	0.63	0.80	0.71	12.17%	7.55%	10.02%	10.55%
American Electric Power Company, Inc.	AEP	4.62%	0.55	0.70	0.62	12.17%	7.55%	9.32%	10.03%
CenterPoint Energy, Inc.	CNP	4.62%	0.67	0.80	0.73	12.17%	7.55%	10.17%	10.67%
CMS Energy Corporation	CMS	4.62%	0.57	0.70	0.63	12.17%	7.55%	9.41%	10.10%
Consolidated Edison, Inc.	ED	4.62%	0.47	0.65	0.56	12.17%	7.55%	8.84%	9.67%
Dominion Energy, Inc.	D	4.62%	0.60	0.80	0.70	12.17%	7.55%	9.89%	10.46%
DTE Energy Company	DTE	4.62%	0.60	0.80	0.70	12.17%	7.55%	9.90%	10.47%
Duke Energy Corporation	DUK	4.62%	0.50	0.65	0.58	12.17%	7.55%	8.97%	9.77%
Entergy Corporation	ETR	4.62%	0.66	0.75	0.71	12.17%	7.55%	9.95%	10.51%
Eversource Energy	ES	4.62%	0.63	0.85	0.74	12.17%	7.55%	10.20%	10.70%
Exelon Corporation	EXC	4.62%	0.63	0.75	0.69	12.17%	7.55%	9.82%	10.40%
FirstEnergy Corporation	FE	4.62%	0.57	0.75	0.66	12.17%	7.55%	9.61%	10.25%
NorthWestern Energy Group, Inc.	NWE	4.62%	0.57	0.75	0.66	12.17%	7.55%	9.61%	10.25%
PPL Corporation	PPL	4.62%	0.63	0.80	0.72	12.17%	7.55%	10.04%	10.57%
Public Service Enterprise Group Inc.	PEG	4.62%	0.71	0.85	0.78	12.17%	7.55%	10.50%	10.92%
Xcel Energy Inc.	XEL	4.62%	0.58	0.70	0.64	12.17%	7.55%	9.44%	10.12%
								Mean:	9.73%
								Median:	9.85%
								Average of the Mean and Median:	9.79%
									10.39%

Notes:

- [1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Kroll Cost of Capital Navigator
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results (Breuning Proxy Group)
Using Long-Term Historical Market Return and 10-Year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	
		Current 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM	
Company	Ticker							
Ameren Corporation	AEE	4.77%	0.72	12.17%	7.40%	10.12%	10.63%	
American Electric Power Company, Inc.	AEP	4.77%	0.71	12.17%	7.40%	10.04%	10.57%	
CenterPoint Energy, Inc.	CNP	4.77%	0.93	12.17%	7.40%	11.64%	11.77%	
CMS Energy Corporation	CMS	4.77%	0.71	12.17%	7.40%	10.00%	10.54%	
Consolidated Edison, Inc.	ED	4.77%	0.59	12.17%	7.40%	9.13%	9.89%	
Dominion Energy, Inc.	D	4.77%	0.68	12.17%	7.40%	9.83%	10.42%	
DTE Energy Company	DTE	4.77%	0.78	12.17%	7.40%	10.58%	10.98%	
Duke Energy Corporation	DUK	4.77%	0.68	12.17%	7.40%	9.81%	10.40%	
Entergy Corporation	ETR	4.77%	0.83	12.17%	7.40%	10.93%	11.24%	
Eversource Energy	ES	4.77%	0.79	12.17%	7.40%	10.59%	10.98%	
Exelon Corporation	EXC	4.77%	0.81	12.17%	7.40%	10.73%	11.09%	
FirstEnergy Corporation	FE	4.77%	0.75	12.17%	7.40%	10.31%	10.78%	
NorthWestern Energy Group, Inc.	NWE	4.77%	0.83	12.17%	7.40%	10.89%	11.21%	
PPL Corporation	PPL	4.77%	0.90	12.17%	7.40%	11.40%	11.60%	
Public Service Enterprise Group Inc.	PEG	4.77%	0.83	12.17%	7.40%	10.91%	11.23%	
Xcel Energy Inc.	XEL	4.77%	0.72	12.17%	7.40%	10.08%	10.60%	
						Mean:	10.44%	10.87%
						Median:	10.45%	10.88%
						Average of the Mean and Median:	10.44%	10.87%
		[7]	[8]	[9]	[10]	[11]	[12]	
		Projected 30- Year Treasury Yield	Bloomberg Beta Coefficient - 10 Year	Long-Term Average Historical Market Return (1926-2024)	Market Risk Premium	Traditional CAPM	Empirical CAPM	
Company	Ticker							
Ameren Corporation	AEE	4.62%	0.72	12.17%	7.55%	10.08%	10.60%	
American Electric Power Company, Inc.	AEP	4.62%	0.71	12.17%	7.55%	9.99%	10.54%	
CenterPoint Energy, Inc.	CNP	4.62%	0.93	12.17%	7.55%	11.62%	11.76%	
CMS Energy Corporation	CMS	4.62%	0.71	12.17%	7.55%	9.95%	10.51%	
Consolidated Edison, Inc.	ED	4.62%	0.59	12.17%	7.55%	9.07%	9.84%	
Dominion Energy, Inc.	D	4.62%	0.68	12.17%	7.55%	9.78%	10.38%	
DTE Energy Company	DTE	4.62%	0.78	12.17%	7.55%	10.54%	10.95%	
Duke Energy Corporation	DUK	4.62%	0.68	12.17%	7.55%	9.76%	10.36%	
Entergy Corporation	ETR	4.62%	0.83	12.17%	7.55%	10.91%	11.22%	
Eversource Energy	ES	4.62%	0.79	12.17%	7.55%	10.56%	10.96%	
Exelon Corporation	EXC	4.62%	0.81	12.17%	7.55%	10.70%	11.07%	
FirstEnergy Corporation	FE	4.62%	0.75	12.17%	7.55%	10.27%	10.75%	
NorthWestern Energy Group, Inc.	NWE	4.62%	0.83	12.17%	7.55%	10.86%	11.19%	
PPL Corporation	PPL	4.62%	0.90	12.17%	7.55%	11.39%	11.58%	
Public Service Enterprise Group Inc.	PEG	4.62%	0.83	12.17%	7.55%	10.89%	11.21%	
Xcel Energy Inc.	XEL	4.62%	0.72	12.17%	7.55%	10.03%	10.57%	
						Mean:	10.40%	10.84%
						Median:	10.41%	10.85%
						Average of the Mean and Median:	10.40%	10.85%

Notes:

[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average

[2] Source: Bloomberg Professional Service

[3] Kroll Cost of Capital Navigator

[4] Equals Col. [3] - Col. [1]

[5] Equals Col. [1] + (Col. [2] x Col. [4])

[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])

[7] Blue Chip Financial Forecasts, Vol. 45, No. 1, December 30, 2025 at 2 and Vol. 44, No. 12, December 1, 2025 at 14

[8] See Note [2]

[9] See Note [3]

[10] Equals Col. [9] - Col. [7]

[11] Equals Col. [7] + (Col. [8] x Col. [10])

[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Adjusted Breuning Forecasted Market Return

Required Rate of Return on Market as a Whole Forecasted

	[1] Projected Dividend Yield	[2] Growth Rate	[3] = [1] + [2] Expected Market Return
Value Line Estimate	1.48%	14.38%	15.86%
[4] S&P 500 Historical Return			12.29%
[5] Average Expected Market Return			<u><u>14.07%</u></u>

Sources:

- [1]** Value Line Screener, Confidential WP-18
- [2]** Value Line Screener, Confidential WP-18
- [3]** Equals [1] + [2]
- [4]** I&E Exhibit No. 3, Schedule 17
- [5]** Equals average of [3] and [4]

Adjusted Input

Adjusted Breuning Capital Asset Pricing Model with Forecasted Return

Scenario 1: Adjusted Risk-free Rate and Market Return Estimate

CAPM with Forecasted Return

Re Required return on individual equity security

Rf Risk-free rate

Rm Required return on the market as a whole

Be Beta on individual equity security

$$Re = Rf + Be(Rm - Rf)$$

$$Rf = 4.60$$

$$Rm = 14.07$$

$$Be = 0.75$$

$$Re = 11.70$$

Sources:

Rf Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 2, 14.
Uses Mr. Breuning's methodology (I&E Exhibit No. 3, Schedule 16) and 30-Yr Treasury Bond yields.

Rm Exhibit JEN-12R, page 1

Be I&E Exhibit No. 3, Schedule 15

Breuning Forecasted CAPM ROE (%)	9.71

Basis Point Delta	199

Adjusted Input

Adjusted Breuning Capital Asset Pricing Model with Forecasted Return

Scenario 2: Adjusted Risk-free Rate only

CAPM with Forecasted Return

Re	Required return on individual equity security
Rf	Risk-free rate
Rm	Required return on the market as a whole
Be	Beta on individual equity security

$$Re = Rf + Be(Rm - Rf)$$

$$Rf = 4.60$$

$$Rm = 11.59$$

$$Be = 0.75$$

$$Re = 9.84$$

Sources:

Rf Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 2, 14.
Uses Mr. Breuning's methodology (I&E Exhibit No. 3, Schedule 16) and 30-Yr Treasury Bond yields.

Rm I&E Exhibit No. 3, Schedule 18

Be I&E Exhibit No. 3, Schedule 15

Breuning Forecasted CAPM ROE (%)	9.71
Basis Point Delta	13

Adjusted Input

Adjusted Breuning Capital Asset Pricing Model with Forecasted Return

Scenario 3: Adjusted Market Return Estimate only

CAPM with Forecasted Return

Re Required return on individual equity security
Rf Risk-free rate
Rm Required return on the market as a whole
Be Beta on individual equity security

$$Re = Rf + Be(Rm - Rf)$$

$$Rf = 4.08$$

$$Rm = 14.07$$

$$Be = 0.75$$

$$Re = 11.57$$

Sources:

Rf I&E Exhibit No. 3, Schedule 16
Rm Exhibit JEN-12R, page 1
Be I&E Exhibit No. 3, Schedule 15

Breuning Forecasted CAPM ROE (%)	9.71

Basis Point Delta	186

Adjusted Input

Illustrative Example: Flotation Cost Recovery

Return on Equity 11.30%
Flotation Costs 2.53%
Market Value/Share \$ 35.00
Dividend Yield 4.50%
Growth Rate 6.80%
Adjusted ROE 11.42%
Flotation Cost Recovery: No
DCF Estimate 11.18%

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	\$ 34.11		\$ 34.11	\$ 35.00	1.0260	\$ 3.85	\$ 1.58	40.86%
2	\$ 34.11	\$ 2.28	\$ 36.39	\$ 37.34	1.0260	\$ 4.11	\$ 1.68	40.86%
3	\$ 34.11	\$ 4.71	\$ 38.83	\$ 39.83	1.0260	\$ 4.39	\$ 1.79	40.86%
4	\$ 34.11	\$ 7.31	\$ 41.42	\$ 42.50	1.0260	\$ 4.68	\$ 1.91	40.86%
5	\$ 34.11	\$ 10.08	\$ 44.19	\$ 45.34	1.0260	\$ 4.99	\$ 2.04	40.86%
6	\$ 34.11	\$ 13.03	\$ 47.14	\$ 48.37	1.0260	\$ 5.33	\$ 2.18	40.86%
7	\$ 34.11	\$ 16.18	\$ 50.29	\$ 51.60	1.0260	\$ 5.68	\$ 2.32	40.86%
8	\$ 34.11	\$ 19.54	\$ 53.66	\$ 55.05	1.0260	\$ 6.06	\$ 2.48	40.86%
9	\$ 34.11	\$ 23.13	\$ 57.24	\$ 58.73	1.0260	\$ 6.47	\$ 2.64	40.86%
10	\$ 34.11	\$ 26.95	\$ 61.07	\$ 62.65	1.0260	\$ 6.90	\$ 2.82	40.86%
Growth Rate			6.68%	6.68%		6.68%	6.68%	

Return on Equity 11.30%
Flotation Costs 2.53%
Market Value/Share \$ 35.00
Dividend Yield 4.50%
Growth Rate 6.80%
Adjusted ROE 11.42%
Flotation Cost Recovery: Yes
DCF Estimate 11.30%

	Common Stock	Retained Earnings	Book Value	Market Price	Market/ Book Value	Earnings Per Share	Dividends Per Share	Payout Ratio
1	\$ 34.11		\$ 34.11	\$ 35.00	1.0260	\$ 3.89	\$ 1.58	40.44%
2	\$ 34.11	\$ 2.32	\$ 36.43	\$ 37.38	1.0260	\$ 4.16	\$ 1.68	40.44%
3	\$ 34.11	\$ 4.80	\$ 38.91	\$ 39.92	1.0260	\$ 4.44	\$ 1.80	40.44%
4	\$ 34.11	\$ 7.44	\$ 41.56	\$ 42.64	1.0260	\$ 4.74	\$ 1.92	40.44%
5	\$ 34.11	\$ 10.27	\$ 44.38	\$ 45.54	1.0260	\$ 5.07	\$ 2.05	40.44%
6	\$ 34.11	\$ 13.29	\$ 47.40	\$ 48.63	1.0260	\$ 5.41	\$ 2.19	40.44%
7	\$ 34.11	\$ 16.51	\$ 50.63	\$ 51.94	1.0260	\$ 5.78	\$ 2.34	40.44%
8	\$ 34.11	\$ 19.95	\$ 54.07	\$ 55.47	1.0260	\$ 6.17	\$ 2.50	40.44%
9	\$ 34.11	\$ 23.63	\$ 57.74	\$ 59.24	1.0260	\$ 6.59	\$ 2.67	40.44%
10	\$ 34.11	\$ 27.56	\$ 61.67	\$ 63.27	1.0260	\$ 7.04	\$ 2.85	40.44%
Growth Rate			6.80%	6.80%		6.80%	6.80%	

Capital Structure Analysis (Breuning Proxy Group)

Proxy Group Company	Ticker	COMMON EQUITY RATIO [1]						
		2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Ameren Corporation	AEE	53.52%	53.94%	53.66%	53.72%	53.09%	53.70%	53.58%
American Electric Power Company, Inc.	AEP	48.58%	48.45%	48.56%	47.76%	48.15%	48.53%	48.30%
CMS Energy Corporation	CMS	48.71%	49.10%	49.78%	52.28%	51.17%	49.19%	50.21%
CenterPoint Energy, Inc.	CNP	46.23%	46.20%	46.73%	44.89%	45.08%	46.39%	45.83%
Dominion Energy, Inc.	D	53.40%	55.08%	52.25%	53.04%	53.16%	53.58%	53.39%
DTE Energy Company	DTE	49.79%	49.72%	50.41%	49.83%	49.45%	49.97%	49.84%
Duke Energy Corporation	DUK	53.08%	52.87%	53.04%	53.39%	52.95%	53.00%	53.07%
Consolidated Edison, Inc.	ED	45.95%	47.50%	46.73%	46.87%	46.77%	46.73%	46.76%
Eversource Energy	ES	56.69%	57.02%	56.45%	54.50%	54.61%	56.72%	55.85%
Entergy Corporation	ETR	51.30%	51.96%	47.65%	45.48%	46.32%	50.30%	48.54%
Exelon Corporation	EXC	52.89%	53.27%	53.42%	53.30%	53.19%	53.19%	53.21%
FirstEnergy Corporation	FE	58.94%	54.19%	55.52%	55.24%	56.98%	56.22%	56.18%
NorthWestern Energy	NWE	50.08%	49.89%	50.34%	47.82%	47.17%	50.10%	49.06%
Public Service Enterprise Group Inc.	PEG	55.03%	55.40%	55.16%	55.17%	54.54%	55.20%	55.06%
PPL Corporation	PPL	56.61%	56.49%	56.76%	57.09%	55.81%	56.62%	56.55%
Xcel Energy Inc.	XEL	54.24%	54.47%	54.84%	54.41%	54.82%	54.52%	54.56%
Proxy Group								
MEAN		52.19%	52.22%	51.96%	51.55%	51.45%	52.12%	51.87%
MEDIAN		52.98%	53.07%	52.64%	53.17%	53.02%	53.10%	53.14%
LOW		45.95%	46.20%	46.73%	44.89%	45.08%	46.39%	45.83%
HIGH		58.94%	57.02%	56.76%	57.09%	56.98%	56.72%	56.55%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Ameren Illinois Company	AEE	55.36%	56.21%	55.63%	55.78%	55.18%	55.73%	55.63%
Union Electric Company	AEE	51.92%	51.87%	51.88%	51.87%	51.22%	51.89%	51.75%
AEP Texas, Inc.	AEP	43.47%	45.69%	42.07%	42.81%	42.41%	43.74%	43.29%
Appalachian Power Company	AEP	50.26%	48.44%	47.76%	48.34%	47.19%	48.82%	48.40%
Indiana Michigan Power Company	AEP	50.18%	48.32%	49.29%	47.38%	48.67%	49.26%	48.77%
Kentucky Power Company	AEP	44.93%	42.26%	43.82%	44.17%	45.28%	43.67%	44.09%
Kingsport Power Company	AEP	52.99%	51.12%	53.89%	54.18%	53.42%	52.67%	53.12%
Ohio Power Company	AEP	50.95%	51.30%	50.79%	48.76%	52.42%	51.01%	50.84%
Public Service Company of Oklahoma	AEP	48.32%	51.75%	55.70%	54.36%	52.88%	51.92%	52.60%
Southwestern Electric Power Company	AEP	51.55%	50.68%	52.54%	48.70%	50.78%	51.59%	50.85%
Wheeling Power Company	AEP	44.66%	39.99%	49.14%	54.01%	54.10%	44.60%	48.38%
Consumers Energy Company	CMS	48.71%	49.10%	49.78%	52.28%	51.17%	49.19%	50.21%
CenterPoint Energy Houston Electric, LLC	CNP	44.52%	44.46%	44.55%	42.04%	41.98%	44.51%	43.51%
Southern Indiana Gas and Electric Company	CNP	55.93%	55.66%	56.48%	56.38%	56.63%	56.02%	56.22%
Dominion Energy South Carolina, Inc.	D	53.14%	52.63%	54.80%	53.94%	56.18%	53.52%	54.14%
Virginia Electric and Power Company	D	53.46%	55.63%	51.62%	52.80%	52.36%	53.57%	53.17%
DTE Electric Company	DTE	49.79%	49.72%	50.41%	49.83%	49.45%	49.97%	49.84%
Duke Energy Carolinas, LLC	DUK	51.08%	52.00%	52.78%	52.05%	52.33%	51.95%	52.05%
Duke Energy Florida, LLC	DUK	53.67%	51.31%	50.74%	52.65%	52.59%	51.91%	52.19%
Duke Energy Indiana, LLC	DUK	53.41%	52.55%	52.06%	53.56%	53.74%	52.67%	53.06%
Duke Energy Kentucky, Inc.	DUK	54.31%	61.54%	52.97%	52.90%	49.54%	56.27%	54.25%
Duke Energy Ohio, Inc.	DUK	62.72%	64.39%	65.87%	64.40%	62.46%	64.32%	63.97%
Duke Energy Progress, LLC	DUK	51.71%	50.72%	51.27%	51.76%	50.69%	51.23%	51.23%
Consolidated Edison Company of New York, Inc.	ED	45.86%	47.44%	46.75%	46.82%	46.74%	46.68%	46.72%
Orange and Rockland Utilities, Inc.	ED	47.75%	48.57%	46.44%	47.69%	47.29%	47.59%	47.55%
NSTAR Electric Company	ES	57.43%	57.61%	56.13%	55.37%	55.24%	57.06%	56.36%
Public Service Company of New Hampshire	ES	56.37%	56.16%	53.77%	49.10%	48.66%	55.43%	52.81%
The Connecticut Light and Power Company	ES	56.06%	56.77%	57.70%	55.53%	56.14%	56.84%	56.44%
Entergy Arkansas, LLC	ETR	47.15%	45.08%	47.95%	47.84%	45.94%	46.73%	46.79%
Entergy Louisiana, LLC	ETR	54.22%	55.45%	47.17%	43.08%	45.62%	52.28%	49.11%
Entergy Mississippi, LLC	ETR	49.50%	49.32%	46.43%	45.53%	48.19%	48.42%	47.79%
Entergy New Orleans, LLC	ETR	48.50%	54.37%	47.94%	45.52%	50.04%	50.27%	49.27%
Entergy Texas, Inc.	ETR	49.74%	50.74%	49.99%	51.32%	47.05%	50.16%	49.77%
Atlantic City Electric Company	EXC	50.02%	49.85%	50.08%	50.04%	49.90%	49.98%	49.98%
Baltimore Gas and Electric Company	EXC	51.98%	54.21%	53.81%	53.40%	53.22%	53.33%	53.32%
Commonwealth Edison Company	EXC	54.70%	54.95%	55.29%	55.13%	55.03%	54.98%	55.02%
Delmarva Power & Light Company	EXC	50.28%	50.22%	50.33%	49.68%	50.05%	50.28%	50.11%
PECO Energy Company	EXC	53.46%	53.10%	53.50%	53.66%	53.35%	53.35%	53.41%
Potomac Electric Power Company	EXC	50.19%	50.10%	50.03%	50.10%	50.12%	50.11%	50.11%
FirstEnergy Pennsylvania Electric Company	FE	52.71%	N/A	N/A	N/A	N/A	52.71%	52.71%
Jersey Central Power & Light Company	FE	67.97%	65.79%	64.86%	64.52%	69.18%	66.21%	66.46%
Metropolitan Edison Company	FE	N/A	49.86%	51.85%	50.96%	49.22%	50.86%	50.47%
Monongahela Power Company	FE	53.58%	45.09%	49.23%	45.10%	46.68%	49.30%	47.94%
Ohio Edison Company	FE	54.89%	57.90%	57.49%	68.75%	72.77%	56.76%	62.36%
Pennsylvania Electric Company	FE	N/A	46.24%	50.97%	50.42%	51.10%	48.61%	49.68%
Pennsylvania Power Company	FE	N/A	53.60%	49.28%	51.00%	49.90%	51.44%	50.94%
The Cleveland Electric Illuminating Company	FE	67.19%	55.54%	55.10%	51.41%	51.47%	59.28%	56.14%
The Potomac Edison Company	FE	51.72%	49.65%	53.39%	51.43%	48.53%	51.59%	50.94%
The Toledo Edison Company	FE	55.44%	54.67%	57.09%	55.02%	64.86%	55.74%	57.42%
West Penn Power Company	FE	N/A	50.03%	48.80%	49.39%	48.55%	49.41%	49.19%
NorthWestern Corporation	NWE	50.08%	49.89%	50.34%	47.82%	47.17%	50.10%	49.06%
Public Service Electric and Gas Company	PEG	55.03%	55.40%	55.16%	55.17%	54.54%	55.20%	55.06%
Kentucky Utilities Company	PPL	54.48%	53.47%	53.86%	55.73%	54.62%	53.94%	54.43%
Louisville Gas and Electric Company	PPL	53.69%	52.83%	54.48%	57.11%	55.89%	53.67%	54.80%
The Narragansett Electric Company	PPL	62.90%	65.94%	65.42%	62.03%	60.54%	64.75%	63.36%
PPL Electric Utilities Corporation	PPL	56.29%	56.26%	56.04%	55.96%	54.57%	56.20%	55.82%
Northern States Power Company - Minnesota	XEL	53.37%	52.58%	52.79%	52.65%	53.19%	52.91%	52.91%
Northern States Power Company - Wisconsin	XEL	53.23%	52.77%	53.45%	52.53%	53.85%	53.15%	53.17%
Public Service Company of Colorado	XEL	55.21%	56.47%	57.18%	56.44%	56.82%	56.29%	56.42%
Southwestern Public Service Company	XEL	54.17%	54.41%	54.30%	54.23%	54.17%	54.29%	54.25%
Operating Company								
MEAN		52.72%	52.37%	52.38%	52.08%	52.25%	52.43%	52.33%
MEDIAN		53.07%	52.00%	52.06%	52.05%	51.47%	51.94%	52.12%
LOW		43.47%	39.99%	42.07%	42.04%	41.98%	43.67%	43.29%
HIGH		67.97%	65.94%	65.87%	68.75%	72.77%	66.21%	66.46%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Rockland Electric was removed because it is financed with 100% common equity.

Capital Structure Analysis (Breuning Proxy Group)

Proxy Group Company	Ticker	LONG-TERM DEBT RATIO [1]					3-Yr Average	5-Yr Average
		2024	2023	2022	2021	2020		
Ameren Corporation	AEE	46.48%	46.06%	46.34%	46.28%	46.91%	46.30%	46.42%
American Electric Power Company, Inc.	AEP	51.42%	51.55%	51.44%	52.24%	51.85%	51.47%	51.70%
CMS Energy Corporation	CMS	51.29%	50.90%	50.22%	47.72%	48.83%	50.81%	49.79%
CenterPoint Energy, Inc.	CNP	53.77%	53.80%	53.27%	55.11%	54.92%	53.61%	54.17%
Dominion Energy, Inc.	D	46.60%	44.92%	47.75%	46.96%	46.84%	46.42%	46.61%
DTE Energy Company	DTE	50.21%	50.28%	49.59%	50.17%	50.55%	50.03%	50.16%
Duke Energy Corporation	DUK	46.92%	47.13%	46.96%	46.61%	47.05%	47.00%	46.93%
Consolidated Edison, Inc.	ED	54.05%	52.50%	53.27%	53.13%	53.23%	53.27%	53.24%
Eversource Energy	ES	43.31%	42.98%	43.55%	45.50%	45.39%	43.28%	44.15%
Entergy Corporation	ETR	48.70%	48.04%	52.35%	54.52%	53.68%	49.70%	51.46%
Exelon Corporation	EXC	47.11%	46.73%	46.58%	46.70%	46.81%	46.81%	46.79%
FirstEnergy Corporation	FE	41.06%	45.81%	44.48%	44.76%	43.02%	43.78%	43.82%
NorthWestern Energy	NWE	49.92%	50.11%	49.66%	52.18%	52.83%	49.90%	50.94%
Public Service Enterprise Group Inc.	PEG	44.97%	44.60%	44.84%	44.83%	45.46%	44.80%	44.94%
PPL Corporation	PPL	43.39%	43.51%	43.24%	42.91%	44.19%	43.38%	43.45%
Xcel Energy Inc.	XEL	45.76%	45.53%	45.16%	45.59%	45.18%	45.48%	45.44%
Proxy Group								
MEAN		47.81%	47.78%	48.04%	48.45%	48.55%	47.88%	48.13%
MEDIAN		47.02%	46.93%	47.36%	46.83%	46.98%	46.90%	46.86%
LOW		41.06%	42.98%	43.24%	42.91%	43.02%	43.28%	43.45%
HIGH		54.05%	53.80%	53.27%	55.11%	54.92%	53.61%	54.17%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	2021	2020	3-Yr Average	5-Yr Average
Ameren Illinois Company	AEE	44.64%	43.79%	44.37%	44.22%	44.82%	44.27%	44.37%
Union Electric Company	AEE	48.08%	48.13%	48.12%	48.13%	48.78%	48.11%	48.25%
AEP Texas, Inc.	AEP	56.53%	54.31%	57.93%	57.19%	57.59%	56.26%	56.71%
Appalachian Power Company	AEP	49.74%	51.56%	52.24%	51.66%	52.81%	51.18%	51.60%
Indiana Michigan Power Company	AEP	49.82%	51.68%	50.71%	52.62%	51.33%	50.74%	51.23%
Kentucky Power Company	AEP	55.07%	57.74%	56.18%	55.83%	54.72%	56.33%	55.91%
Kingsport Power Company	AEP	47.01%	48.88%	46.11%	45.82%	46.58%	47.33%	46.88%
Ohio Power Company	AEP	49.05%	48.70%	49.21%	51.24%	47.58%	48.99%	49.16%
Public Service Company of Oklahoma	AEP	51.68%	48.25%	44.30%	45.64%	47.12%	48.08%	47.40%
Southwestern Electric Power Company	AEP	48.45%	49.32%	47.46%	51.30%	49.22%	48.41%	49.15%
Wheeling Power Company	AEP	55.34%	60.01%	50.86%	45.99%	45.90%	55.40%	51.62%
Consumers Energy Company	CMS	51.29%	50.90%	50.22%	47.72%	48.83%	50.81%	49.79%
CenterPoint Energy Houston Electric, LLC	CNP	55.48%	55.54%	55.45%	57.96%	58.02%	55.49%	56.49%
Southern Indiana Gas and Electric Company	CNP	44.07%	44.34%	43.52%	43.62%	43.37%	43.98%	43.78%
Dominion Energy South Carolina, Inc.	D	46.86%	47.37%	45.20%	46.06%	43.82%	46.48%	45.86%
Virginia Electric and Power Company	D	46.54%	44.37%	48.38%	47.20%	47.64%	46.43%	46.83%
DTE Electric Company	DTE	50.21%	50.28%	49.59%	50.17%	50.55%	50.03%	50.16%
Duke Energy Carolinas, LLC	DUK	48.92%	48.00%	47.22%	47.95%	47.67%	48.05%	47.95%
Duke Energy Florida, LLC	DUK	46.33%	48.69%	49.26%	47.35%	47.41%	48.09%	47.81%
Duke Energy Indiana, LLC	DUK	46.59%	47.45%	47.94%	46.44%	46.26%	47.33%	46.94%
Duke Energy Kentucky, Inc.	DUK	45.69%	38.46%	47.03%	47.10%	50.46%	43.73%	45.75%
Duke Energy Ohio, Inc.	DUK	37.28%	35.61%	34.13%	35.60%	37.54%	35.68%	36.03%
Duke Energy Progress, LLC	DUK	48.29%	49.28%	48.73%	48.24%	49.31%	48.77%	48.77%
Consolidated Edison Company of New York, Inc.	ED	54.14%	52.56%	53.25%	53.18%	53.26%	53.32%	53.28%
Orange and Rockland Utilities, Inc.	ED	52.25%	51.43%	53.56%	52.31%	52.71%	52.41%	52.45%
NSTAR Electric Company	ES	42.57%	42.39%	43.87%	44.63%	44.76%	42.94%	43.64%
Public Service Company of New Hampshire	ES	43.63%	43.84%	46.23%	50.90%	51.34%	44.57%	47.19%
The Connecticut Light and Power Company	ES	43.94%	43.23%	42.30%	44.47%	43.86%	43.16%	43.56%
Entergy Arkansas, LLC	ETR	52.85%	54.92%	52.05%	52.16%	54.06%	53.27%	53.21%
Entergy Louisiana, LLC	ETR	45.78%	44.55%	52.83%	56.92%	54.38%	47.72%	50.89%
Entergy Mississippi, LLC	ETR	50.50%	50.68%	53.57%	54.47%	51.81%	51.58%	52.21%
Entergy New Orleans, LLC	ETR	51.50%	45.63%	52.06%	54.48%	49.96%	49.73%	50.73%
Entergy Texas, Inc.	ETR	50.26%	49.26%	50.01%	48.68%	52.95%	49.84%	50.23%
Atlantic City Electric Company	EXC	49.98%	50.15%	49.92%	49.96%	50.10%	50.02%	50.02%
Baltimore Gas and Electric Company	EXC	48.02%	45.79%	46.19%	46.60%	46.78%	46.67%	46.68%
Commonwealth Edison Company	EXC	45.30%	45.05%	44.71%	44.87%	44.97%	45.02%	44.98%
Delmarva Power & Light Company	EXC	49.72%	49.78%	49.67%	50.32%	49.95%	49.72%	49.89%
PECO Energy Company	EXC	46.54%	46.90%	46.50%	46.34%	46.65%	46.65%	46.59%
Potomac Electric Power Company	EXC	49.81%	49.90%	49.97%	49.90%	49.88%	49.89%	49.89%
FirstEnergy Pennsylvania Electric Company	FE	47.29%	N/A	N/A	N/A	N/A	47.29%	47.29%
Jersey Central Power & Light Company	FE	32.03%	34.21%	35.14%	35.48%	30.82%	33.79%	33.54%
Metropolitan Edison Company	FE	N/A	50.14%	48.15%	49.04%	50.78%	49.14%	49.53%
Monongahela Power Company	FE	46.42%	54.91%	50.77%	54.90%	53.32%	50.70%	52.06%
Ohio Edison Company	FE	45.11%	42.10%	42.51%	31.25%	27.23%	43.24%	37.64%
Pennsylvania Electric Company	FE	N/A	53.76%	49.03%	49.58%	48.90%	51.39%	50.32%
Pennsylvania Power Company	FE	N/A	46.40%	50.72%	49.00%	50.10%	48.56%	49.06%
The Cleveland Electric Illuminating Company	FE	32.81%	44.46%	44.90%	48.59%	48.53%	40.72%	43.86%
The Potomac Edison Company	FE	48.28%	50.35%	46.61%	48.57%	51.47%	48.41%	49.06%
The Toledo Edison Company	FE	44.56%	45.33%	42.91%	44.98%	35.14%	44.26%	42.58%
West Penn Power Company	FE	N/A	49.97%	51.20%	50.61%	51.45%	50.59%	50.81%
NorthWestern Corporation	NWE	49.92%	50.11%	49.66%	52.18%	52.83%	49.90%	50.94%
Public Service Electric and Gas Company	PEG	44.97%	44.60%	44.84%	44.83%	45.46%	44.80%	44.94%
Kentucky Utilities Company	PPL	45.52%	46.53%	46.14%	44.27%	45.38%	46.06%	45.57%
Louisville Gas and Electric Company	PPL	46.31%	47.17%	45.52%	42.89%	44.11%	46.33%	45.20%
The Narragansett Electric Company	PPL	37.10%	34.06%	34.58%	37.97%	39.46%	35.25%	36.64%
PPL Electric Utilities Corporation	PPL	43.71%	43.74%	43.96%	44.04%	45.43%	43.80%	44.18%
Northern States Power Company - Minnesota	XEL	46.63%	47.42%	47.21%	47.35%	46.81%	47.09%	47.09%
Northern States Power Company - Wisconsin	XEL	46.77%	47.23%	46.55%	47.47%	46.15%	46.85%	46.83%
Public Service Company of Colorado	XEL	44.79%	43.53%	42.82%	43.56%	43.18%	43.71%	43.58%
Southwestern Public Service Company	XEL	45.83%	45.59%	45.70%	45.77%	45.83%	45.71%	45.75%
Operating Company								
MEAN		47.28%	47.63%	47.62%	47.92%	47.75%	47.57%	47.67%
MEDIAN		46.93%	48.00%	47.94%	47.95%	48.53%	48.06%	47.88%
LOW		32.03%	34.06%	34.13%	31.25%	27.23%	33.79%	33.54%
HIGH		56.53%	60.01%	57.93%	57.96%	58.02%	56.33%	56.71%

Notes:

Sources: Operating Company FERC Form 1; S&P Capital IQ

[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.

[2] Rockland Electric was removed because it is financed with 100% common equity.

Pa. PUC v. PPL Electric Utilities Corporation

Docket No. R-2025-3057164

**CAUSE-PA RESPONSES TO INTERROGATORIES AND REQUESTS FOR
PRODUCTION OF DOCUMENTS BY PPL – SET II**

PPL to CAUSE-PA II-1. Please refer to CAUSE-PA Statement No. 1, page 10. Did Mr. Cicero evaluate whether any other utility companies also have “modified traditional cost of service ratemaking” mechanisms? If so, please provide all analyses Mr. Cicero performed, or reports relied upon, regarding the “modified traditional cost of service ratemaking” mechanisms that are employed by other utility companies.

CAUSE-PA RESPONSE:

In the context of this case, no. However, to the extent that any other utility utilizes the Fully Projected Future Test Year, the Distribution System Improvement Charge, or any other alternative ratemaking methodology provided in 66 Pa. C.S. § 1330, then they would be availing themselves of the ways in which Pennsylvania has modified traditional cost of service ratemaking.

By way further answer, please see Mr. Cicero’s analysis of how other utilities have availed themselves of these same tools as outlined in the testimony he submitted in various other state utility rate proceedings. His testimony submitted in these proceedings was attached to CAUSE-PA Response to PPL, I-3.

Response prepared by or under the supervision of Patrick Cicero.

Dated: January 9, 2026

VERIFICATION

I, Patrick Cicero, hereby state that the facts set forth in my responses to the Interrogatories and Requests for Production of Documents, PPL to CAUSE-PA, Set II are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at hearing held in this matter. I understand that the statements made herein are subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).



Patrick Cicero
Witness, CAUSE-PA

Dated: January 9, 2026

PA PUC Docket No. R-2025-3057164

Question:
PPL-EJA-I-9

Date of Response:
01/02/2026

Response Provided By:
Karl R. Rábago

Question

Reference EJA Statement No. 1, pp. 25-27. Is Mr. Rábago aware of any state utility commission that has used his proposed methodology for determining the return on common equity in a base rate proceeding? If so, please identify each such proceeding, providing the case caption, state utility commission, and docket number.

Answer

Mr. Rábago is not aware whether any regulatory authorities have used the methodology described in his testimony.

VERIFICATION

I hereby verify that my above statements are true and accurate to the best of my knowledge and that I am duly authorized to make this verification, and that I expect to be able to prove the same at any hearing held in this matter. I understand that the statements herein are made subject to penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Dated: January 2, 2026

/s/

Karl R. Rábago

**Pennsylvania Public Utility Commission v.
PPL Electric Utilities Corporation
Docket No. R-2025-3057164**

**Responses of the Bureau of Investigation and Enforcement to the
Interrogatories of PPL Electric Utilities Corporation – Set II
Witness: Drew Breuning**

- PPL-I&E-II-2 Please refer to I&E Exhibit No. 3, Schedule 4. Please explain whether Staff's proxy group capital structure data from S&P at the holding company level finances unregulated operations.
- a. If so, please explain why Staff did not perform its proxy group capital structure analysis limiting the data to capital that finances only regulated utility rate base, particularly considering Staff's statement on I&E Statement No. 3, page 4, lines 20-22 that a utility's capital structure is determined by calculating the percentage of each capitalization component that finances rate base to total capital.
 - b. Please recalculate I&E Exhibit No. 3, Schedule 4 using only capital that supports the regulated electric utility operations of Staff's proxy group companies.

Response Mr. Breuning did not perform a detailed comprehensive analysis of all financing activities at the holding company level for the companies in his proxy group. However, he concedes it is likely that some of the financing contained in the capital structures of each company were used to finance unregulated operations.

a) I&E relied on data from S&P Global Market Intelligence – Data Management Solutions (Compustat) for ascertaining the reasonableness of PPL's claim regarding capitalization ratios. Compustat does not provide a breakdown of financial information at an operating company level. Additionally, operating companies' stocks are not listed, and the use of operating company level information for capital structure would yield inconsistent and incorrect results with the holding company's financial data (namely stock price, dividend forecast, growth rate, and beta), all of which are used in calculations of the DCF and CAPM models. It is also important to note that an operating company does not issue

**Pennsylvania Public Utility Commission v.
PPL Electric Utilities Corporation
Docket No. R-2025-3057164**

**Responses of the Bureau of Investigation and Enforcement to the
Interrogatories of PPL Electric Utilities Corporation – Set II
Witness: Drew Breuning**

equity stocks in the capital market and relies on equity contribution from the holding company. In many cases, the holding company provides or allocates debt or equity capital using its financing or funding sources.

b) Refer to the response to Part A above.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
	:	
v.	:	
	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Amortization of Net Salvage
 Depreciation Service Lives**

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is John J. Spanos. My business address is 300 Sterling Parkway,
4 Mechanicsburg, Pennsylvania 17050 (formerly 207 Senate Avenue, Camp Hill,
5 Pennsylvania 17011).

6
7 **Q. Are you the same John J. Spanos that presented direct testimony on behalf of PPL**
8 **Electric Utilities Corporation (“PPL Electric” or the “Company”) in this**
9 **proceeding?**

10 A. Yes, I am. I submitted PPL Electric Statement No. 11 and three accompanying exhibits:
11 (1) PPL Electric Exhibit JJS-1 (Depreciation Study Related to Electric Plant as of June
12 30, 2025); (2) PPL Electric Exhibit JJS-2 (Depreciation Study Related to Electric Plant
13 as of June 30, 2026); and (3) PPL Electric Exhibit JJS-3 (Depreciation Study Related to
14 Electric Plant as of June 30, 2027) (individually, a “Depreciation Study” and
15 collectively “Depreciation Studies”). PPL Electric Exhibits JJS-1, JJS-2, and JJS-3 are
16 depreciation studies as of the end of the historic test year (“HTY”), the future test year
17 (“FTY”), and the fully projected fully test year (“FPFTY”), respectively.

18
19 **Q. What is the purpose of your rebuttal testimony?**

20 A. My rebuttal testimony is three-fold. First, I explain that the five-year amortization of
21 net salvage is a standard and well-accepted expense that I calculated as part of the
22 Depreciation Studies, as set forth in Sections VIII of each study, which was
23 inadvertently omitted from the calculation of PPL Electric’s revenue increase. Second,

1 I respond to, and refute, the depreciation-related direct testimony of David J. Garrett on
2 behalf of the Pennsylvania Office of Consumer Advocate (“OCA”) pertaining to
3 depreciation. OCA witness Garrett proposed alternative, significantly longer, average
4 service life estimates for five plant accounts. Third, I explain that OCA witness Garrett
5 failed to make the appropriate adjustment to the book reserve that would be required if
6 Mr. Garrett’s unreasonable service lives were used.

7
8 **Q. Please summarize your rebuttal testimony.**

9 A. First, I will address the net salvage amortization that PPL Electric inadvertently did not
10 include in the calculation of its proposed revenue increase. Second, I will discuss the
11 practices employed in proceedings before the Pennsylvania Public Utility Commission
12 (“PUC” or the “Commission”) as they relate to the frequency of life estimation (i.e.,
13 service life) studies. Specifically, I will explain why the Company’s service lives are
14 more reasonable than those that Mr. Garrett has proposed in his direct testimony. Third,
15 I will explain why changing life estimates, as Mr. Garrett has proposed for five plant
16 accounts, also requires a change in the development of the book reserve for the FTY
17 and FPFTY, which Mr. Garrett has not done.

18
19 **II. AMORTIZATION OF NET SALVAGE**

20 **Q. Is it standard practice in Pennsylvania to include a five-year amortization of net**
21 **salvage as a part of depreciation expense?**

22 A. Yes, it is. Net salvage consists of gross salvage less the cost of removal. Consistent
23 with practices before the PUC, net salvage is calculated over a historic five-year period.

1 For the vast majority of plant accounts, net salvage is negative (the cost of removal
2 exceeds gross salvage) and, therefore, collectively, for all plant accounts, net salvage is
3 generally negative. That was the case for PPL Electric in this case. It is also consistent
4 with practices before the PUC to amortize net salvage over five years as an additional
5 component of the annual accrual and annual depreciation expense. The amortization of
6 net salvage was presented as part of the Depreciation Studies in Table 2 of PPL Electric
7 Exhibit JJS-1 for the HTY, Table 4 of PPL Electric Exhibit JJS-2 for the FTY, and Table
8 4 of PPL Electric Exhibit JJS-3 for the FPFTY.

9
10 **Q. Are the amounts to be included as the claimed depreciation expense for each of the**
11 **HTY, FTY, and FPFTY?**

12 A. Yes, it should be included, which is consistent with the long-standing practice before
13 the PUC.

14
15 **Q. Was the amortization of net salvage inadvertently left out of the depreciation**
16 **expense that was included in the Company development of revenue requirement**
17 **for each of the HTY, FTY, and FPFTY?**

18 A. Yes, it is my understanding that it was.

19
20 **Q. What amount should be added to the annual depreciation expense for the FPFTY,**
21 **which is the test year PPL Electric is principally relying upon to support its**
22 **proposed revenue increase?**

1 A. As shown in PPL Electric Exhibit JJS-3, at pages I-6 and I-7, column 5, the amortization
2 of net salvage for the FPFTY should be an addition to annual depreciation expense of
3 \$34,591,500. This amount reflects the average amount of the five-year amortization for
4 years 2021-2025 and for 2022-2026 for the Pennsylvania jurisdictional accounts.
5 However, that amount consists of \$34,649,552 for Distribution Plant and (\$58,052) for
6 General Plant. My understanding is that the General Plant is allocated between
7 Transmission and Distribution Plant, so of the (\$58,052), the Company has allocated
8 \$7,725 to Transmission and (\$65,777) to Distribution. Thus, PPL Electric's claim for
9 annual amortization of negative net salvage is \$34,583,774.
10

11 **III. MASS PROPERTY SERVICE LIVES**

12 **Q. Has a service life study been conducted specifically for this rate case?**

13 A. No. It was not necessary to prepare a service life study for this rate case because the
14 Commission's regulation at 52 Pa. Code § 73.5 provides that an electric public utility
15 with gross intrastate revenues exceeding \$20 million per year "shall file a service life
16 study report every 5 years." The most recent prior service life study was conducted by
17 Gannett Fleming in 2022, and the service life parameters established by that service life
18 study have been used by PPL Electric to record depreciation expense on its regulated
19 books of account and for financial reporting purposes since that time. Therefore, there
20 was no need to update the service life estimates for this proceeding. The next service
21 life study update will not be required until 2027.
22

1 **Q. Please explain the difference between depreciation studies, which the Company**
2 **filed with its supporting data in this case, and a service life study?**

3 A. A service life study employs the retirement rate method to analyze historical plant data,
4 together with professional judgment, to develop reasonable estimates of the average
5 service life of property recorded in each mass property account. Those average service
6 lives are used to develop depreciation rates, expressed as a percentage, for each plant
7 account. As I previously explained, PPL Electric completed its last service life study in
8 2022, which it filed with the Commission. A depreciation study, such as those filed in
9 this case, uses the service life parameters developed in a prior service life study to
10 calculate annual depreciation expense based on the plant balances for the applicable test
11 year or years.

12
13 **Q. What do the Commission's regulations state regarding the effect of filing a service**
14 **life study pursuant to 52 Pa. Code § 73.5?**

15 A. The Commission's regulations at 52 Pa. Code § 73.9(b) and (c) state as follows:

16 (a) A service life study or annual depreciation report containing proposed
17 changes to service lives or other depreciation parameters or methods, will
18 be deemed approved by the Commission, for accounting purposes only,
19 within 180 days from the filing date unless the Commission takes other
20 action. The filing utility may request Commission authorization to
21 implement proposed changes in a new service life study.

22
23 (b) In subsequent ratemaking proceedings, the most recent depreciation
24 report or service life study approved or deemed approved for accounting
25 purposes only under this chapter, constitutes a rebuttable presumption as to
26 the reasonableness of the accrued depreciation claimed for ratemaking
27 purposes, and the burden of proving the unreasonableness of the accrued
28 depreciation shall be on the challenging party.

1 **Q. Was the service life study PPL Electric filed in 2022 deemed approved by the**
2 **Commission for accounting purposes?**

3 A. Yes, it was. The Commission took no action for 180 days following the filing of the
4 service life study and, pursuant to Section 73.9(b), the service lives were deemed
5 approved for accounting purposes.

6
7 **Q. Did PPL Electric use the service lives from the 2022 service life study to calculate**
8 **the depreciation rates used to record depreciation expense?**

9 A. Yes. The Company used the service life estimates in its 2022 service life study to
10 calculate the depreciation rates it employed to record depreciation expense for each
11 fiscal year since that study was performed, including depreciation expense recorded on
12 its financial statements for financial reporting purposes.

13
14 **Q. Did OCA Witness Garrett propose changes to any of the service lives for mass**
15 **property proposed by PPL Electric?**

16 A. Yes. Although the service lives from the last service life study are still being used by
17 PPL Electric to record annual depreciation expense, Mr. Garrett has proposed changes
18 to the average service lives of five plant accounts, consisting of one transmission
19 account and four distribution accounts. It should be noted that the transmission account
20 is not Pennsylvania jurisdictional.

21

1 **Q. Please summarize the adjustments Mr. Garrett proposed.**

2 A. Mr. Garrett has proposed adjustments to the survivor curves for five plant accounts, as
3 shown below:

Account	PPL	OCA
Account 356, Overhead Conductors and Devices	65-R2.5	73-R2
Account 364.4, Poles, Towers and Fixtures	55-R0.5	59-R0.5
Account 366, Underground Conduit	70-R3	80-R2.5
Account 367, Underground Conductors and Devices	56-R2.5	62-R2
Account 369, Services	60-R2	68-R1.5

4 For the Depreciation Studies presented in this case, I have continued to use the average
5 service lives that were developed in the last (2022) service life study. In contrast, Mr.
6 Garrett proposes to lengthen the average service lives of each of the accounts identified
7 above by as much as 10 years for some accounts. Mr. Garrett's proposed adjustments
8 are significant increases when compared to the current estimates. For example, for
9 Account 366, a 10-year increase in average life increase represents an increase in the
10 maximum life increase of that account by more than 20 years.

11 Mr. Garrett's proposed adjustments are not reasonable. His recommendations
12 are the product of the flawed analysis Mr. Garrett used to develop his estimates, which
13 relies primarily on mathematical curve fitting, as I explain later in my rebuttal
14 testimony. Mr. Garrett's approach does not give adequate or appropriate consideration
15 to the mortality characteristics of the assets he purported to study or to other factors that
16 should be considered in developing reasonable service life estimates.

17

1 **A. The Estimation of Service Lives Is Not a Purely Mathematical Exercise and Must**
2 **Incorporate Informed Judgment**

3 **Q. Has Mr. Garrett used the same approach to estimating service lives as you used in**
4 **the last service life study?**

5 A. No. While both Mr. Garrett and I used the retirement rate method to analyze historical
6 data and Iowa type survivor curves to smooth and extend the observed life data, Mr.
7 Garrett's overall approach differs from mine in several important ways. Mr. Garrett's
8 approach also differs from the correct and proper approach to estimating service lives
9 that is set forth in authoritative treatises on depreciation, such as the National
10 Association of Regulatory Utility Commissioners ("NARUC") *Public Utility*
11 *Depreciation Practices* ("NARUC Treatise"). Specifically, Mr. Garrett's direct
12 testimony indicates that he believes estimating service lives is primarily a mathematical
13 exercise in which little more than mathematical computations of historical accounting
14 data will produce reasonable service life estimates.¹ This interpretation of Mr. Garrett's
15 testimony related to his manner of determining survivor curves is based on the fact that
16 all of his discussion relates to mathematical curve fitting. He selectively deviates from
17 the overall life cycle of each account by statistically segregating portions of the life table
18 that he views to be insignificant. The overall approach is incorrect. Depreciation, and
19 particularly estimating service lives, is a forecast of the future rather than a calculation
20 of what has happened in the past.

¹ OCA St. 3, p. 68, lines 12-16.

1 **Q. Please explain in more detail why Mr. Garrett’s approach does not comply with**
2 **the proper approach to determining reasonable service life estimates.**

3 A. Consider, as an example, the following statement from Mr. Garrett’s testimony in which
4 he describes the curve-fitting process:

5 Mathematical curve fitting promotes objective, unbiased results. While
6 mathematical curve-fitting is important, it may not always yield the
7 optimum result. Simply determining which Iowa curve best fits an OLT
8 curve ignores professional judgment that may be needed for specific
9 situations. For example, if there is insufficient historical data in a
10 particular account and the OLT curve derived from that data is relatively
11 short and flat, the mathematically “best” curve may be one with a very
12 long average life. However, when there is sufficient data available,
13 mathematical curve fitting can be used as part of an objective service life
14 analysis.²

15 Mr. Garrett’s direct testimony creates the erroneous impression that mathematical
16 results should generally be accepted, and instances in which the proper service life
17 estimate is not a best “mathematical fit” would be a relatively unusual exception (such
18 as, if there is insufficient data). His purported justification for relying on the results of
19 mathematical curve fitting is that doing so promotes “objectivity.” While one may
20 desire “objective” results to remove uncertainty and presumably to make the job of
21 estimating service lives easier, the objectivity sought by Mr. Garrett is neither realistic
22 nor desirable in developing an accurate and reasonable forecast of the future. Further,
23 recognized authorities on the subject of depreciation, such as NARUC, are clear that
24 estimating service lives must include the exercise of the analyst’s informed professional
25 judgment.

² OCA St. 3, p. 64, lines 15-22.

1 **Q. Does the NARUC Treatise explain and emphasize the importance of using**
2 **informed professional judgment in estimating service lives?**

3 A. Yes. The NARUC Treatise explains the role that professional judgment plays in
4 estimating service lives. Chapter XIII of the NARUC Treatise, entitled “Actuarial Life
5 Analysis,” discusses and emphasizes the use of informed professional judgment in the
6 process of estimating service lives. NARUC starts this chapter by explaining that the
7 analysis of historical data is only one part of the process of estimating service lives:

8 Actuarial analysis objectively measures how the company
9 has retired its investment. The analyst must then judge
10 whether this historical view depicts the future life of the
11 property in service. The analyst takes into consideration
12 various factors, such as changes in technology, services
13 provided, or capital budgets.³

14
15 NARUC further explains that the process of estimating service lives must consider more
16 than just an allegedly “objective” measurement of past retirements. In describing the
17 determination of a survivor curve estimate (referred to as the “projection life” in this
18 passage), NARUC states:

19 The projection life is a projection, or forecast, of the future
20 of the property. Historical indications may be useful in
21 estimating a projection life curve. Certainly, the
22 observations based on the property’s history are a starting
23 point. Trends in life or retirement dispersion can often be
24 expected to continue. Likewise, unless there is some reason
25 to expect otherwise, stability in life or retirement dispersion
26 can be expected to continue, at least in the near term.

27
28 Depreciation analysts should avoid becoming ensnared in
29 the mechanics of the historical life study and relying solely
30 on mathematical solutions. The reason for making an
31 historical life analysis is to develop a sufficient
32 understanding of history in order to evaluate whether it is a
33 reasonable predictor of the future. The importance of being

³ NARUC Treatise (1996), p. 111.

1 aware of circumstances having direct bearing on the reason
2 for making an historical life analysis cannot be understated.
3 These circumstances, when factored into the analysis,
4 determine the application and limitations of an historical life
5 analysis.⁴

6
7 Thus, NARUC strongly advises against the approach used by Mr. Garrett by stating
8 clearly that “relying solely on mathematical solutions” should be avoided. NARUC
9 further elaborates on the need for the analyst’s “informed judgment” in forecasting
10 service lives:

11 A depreciation study is commonly described as having three
12 periods of analysis: the past, present, and future. The past
13 and present can usually be analyzed with great accuracy
14 using many currently available analytical tools. The future
15 still must be predicted and must largely include some
16 subjective analysis. *Informed judgment* is a term used to
17 define the subjective portion of the depreciation study
18 process. It is based on a combination of general experience,
19 knowledge of the properties and a physical inspection,
20 information gathered throughout the industry, and other
21 factors which assist the analyst in making a knowledgeable
22 estimate.

23
24 The use of informed judgment can be a major factor in
25 forecasting. A logical process of examining and prioritizing
26 the usefulness of information must be employed, since there
27 are many sources of data that must be considered and
28 weighed by importance. For example, the following forces
29 of retirement need to be considered: Do the past and current
30 service life dispersions represent the future? Will scrap
31 prices rise or fall? What will be the impact of future
32 technological obsolescence? Will the company be in
33 existence in the future? The analyst must rank the factors
34 and decide the relative weight to apply to each. The final
35 estimate might not resemble any one of the specific factors;
36 however, the result would be a decision based upon a
37 combination of the components.⁵

⁴ NARUC Treatise, p. 126 (emphasis added).

⁵ NARUC Treatise, p. 128 (emphasis added).

1 **Q. Have you incorporated the various factors discussed by NARUC into your**
2 **estimates?**

3 A. Yes. For the most recent service life study, I conducted site visits and discussions with
4 Company personnel to familiarize myself with the Company's assets. I have also
5 performed previous depreciation studies for the Company and have incorporated
6 information obtained from those studies as well. In addition, throughout my career, I
7 have performed hundreds of depreciation studies for numerous utilities. The
8 information obtained from this experience has also been incorporated into my
9 recommendations.

10
11 **Q. Has Mr. Garrett incorporated these factors into his recommendations?**

12 A. No, at least not to the degree necessary to develop a reasonable forecast. Estimating
13 service lives is not, and should not be, a purely mathematical exercise and must include
14 some degree of "informed judgment." Mr. Garrett's process for estimating service lives,
15 as described in his direct testimony, does not follow the proper approach of
16 incorporating informed judgment. Further, as I will explain later in my testimony, his
17 actual estimates show that he did not properly consider all of the relevant factors needed
18 to develop reasonable service life estimates. Additionally, he disregards portions of the
19 life table for accounts where the older aged assets or the tail of the life table are as
20 important as younger ages based on the nature of the assets in the account.

21

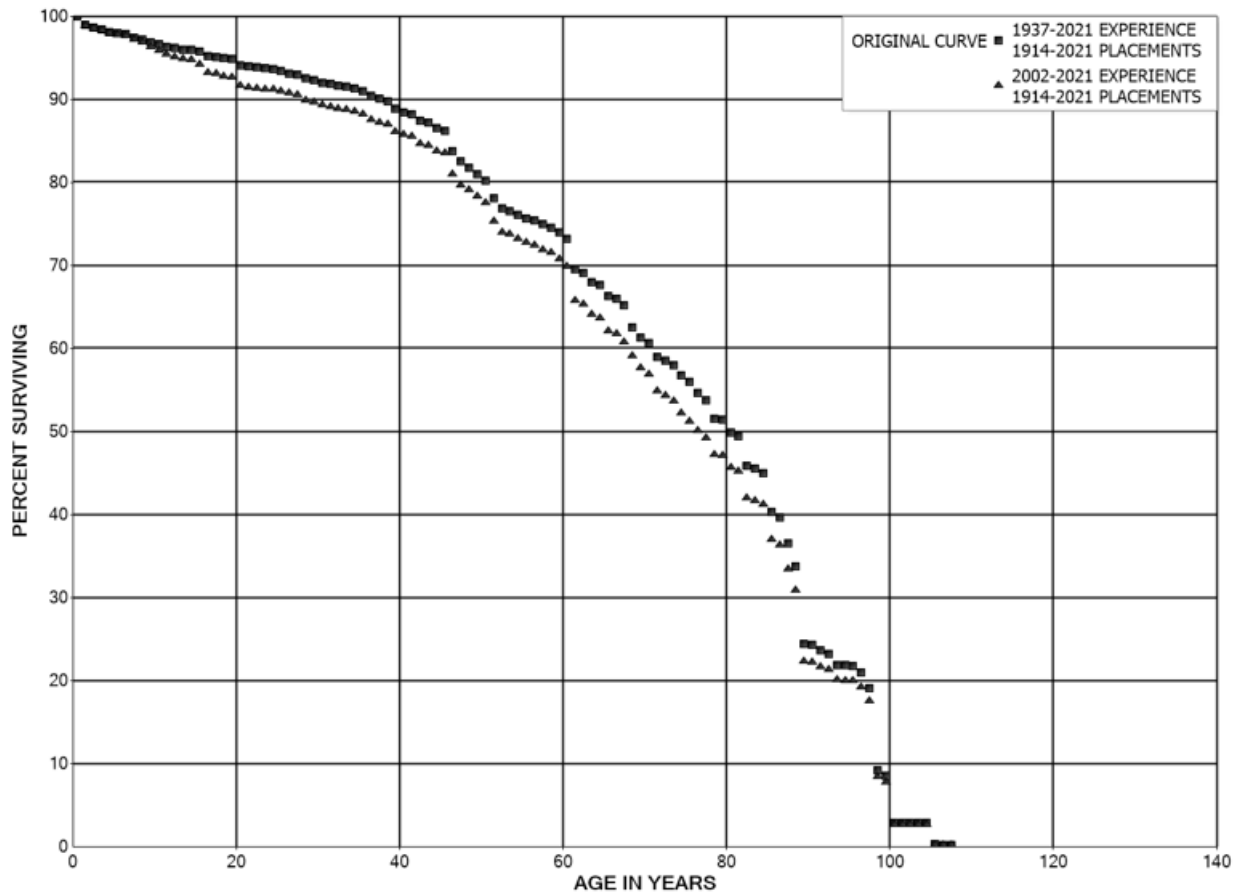
1 **B. The Curve Fitting Process Must Also Incorporate Informed Judgment**

2 **Q. Please briefly describe the curve fitting process used in a depreciation study.**

3 A. As described in both Mr. Garrett's direct testimony and in the Depreciation Study for
4 the FTY (PPL Electric Exhibit JJS-2), the statistical life analysis we both used is referred
5 to as the retirement rate method. The retirement rate method is used when aged data are
6 available. Specifically, the retirement rate method requires the vintage year of historical
7 transactions so that the age of each transaction can be accurately determined. The
8 retirement rate method develops an original life table⁶ ("OLT"), or a series of original
9 life tables, for each depreciable group. An OLT presents calculations, based on the
10 historical data, of the percentage of plant that has survived to a given age. The OLT can
11 also be shown graphically with age in the x-axis and the percent surviving in the y-axis.
12 An example of an OLT graph for the full experience and placement bands for Account
13 356, Overhead Conductors and Devices, is provided in Figure 1 below. The life table
14 itself is presented as Part VI (*Service Life Statistics*), pagers VI-34 through VI-39 of
15 PPL Electric Exhibit JJS-2.

⁶ Original life tables may also be referred to as "observed life tables" or the shorthand "life tables."

Figure 1: Graph of Original Life Table for Account 356, Overhead Conductors and Devices



For the curve fitting process, the analyst can fit or match standard Iowa survivor curves to the data from an OLT. This can be performed either visually or mathematically. For visual curve matching, Iowa curves are graphed on the same graph as the OLT. For mathematical curve matching, the mathematical deviation from a given Iowa curve to the OLT is calculated for each data point using the “sum-of-squared-differences” (“SSD”). The lower the difference between a given survivor curve and the OLT (as measured by the SSD), the better the “mathematical” (i.e., statistical) fit.

1 **Q. Are there advantages and disadvantages to both visual and mathematical curve**
2 **matching?**

3 A. Yes. Visual curve matching offers a number of advantages over mathematical curve
4 matching. Different ranges of data points can be given more or less emphasis depending
5 on the characteristics of the account. It is easier to identify irregularities in the data
6 when performing visual curve matching. Visual curve matching also allows the analyst
7 to view the full Iowa survivor curve to assess whether the full life cycle forecasted by a
8 given Iowa curve is reasonable for the property studied. Understanding the nature of
9 the assets within the account and a reasonable full life cycle of the account is not
10 considered by Mr. Garrett, based on the estimated full life cycle of his survivor curve.

11 Many years ago, a disadvantage of visual curve matching was that it was
12 cumbersome because of the need to manually overlay standard curves on plots of
13 original life tables. However, since the advent of computers with sophisticated
14 graphical capabilities, visual curve matching has become easier and more efficient. As
15 a result, in recent decades the advantages of visual curve matching have made it more
16 prominent, and it is used by most depreciation analysts.

17 Mr. Garrett discusses the alleged advantages of mathematical curve matching in
18 his direct testimony, including his opinion that it promotes “objective, unbiased
19 results.”⁷ Although mathematical curve matching provides a numerical value reflecting
20 the statistical “fit” of an Iowa curve to the OLT data, Mr. Garrett does not discuss the
21 disadvantages of mathematical curve matching or the fact that mathematical curve
22 matching can also introduce biases. One of the disadvantages of mathematical curve

⁷ OCA St. 3, p. 64, line 15.

1 matching is that it treats every data point within a range of fit equally. Different data
2 points are typically based on different levels of data and different ages (e.g., older data
3 points typically are based on much smaller levels of investment than earlier data points).
4 There is not a good way to de-emphasize the irregularities in the data when performing
5 mathematical curve matching, other than to exclude older data points entirely.

6 However, excluding older data points when they present a full life cycle is not
7 appropriate either. Mathematical curve matching can also introduce biases because of
8 the nature of the statistical calculations. As previously explained, indicators of
9 mathematical “fit” are typically calculated by squaring the differences between the OLT
10 points and a given Iowa curve. As a result, the mathematical curve fitting routine will
11 amplify larger differences between the Iowa curve and OLT. Because data irregularities
12 are often common towards the end of the curve when smaller amounts of data are
13 available, the real-world result is that mathematical curve matching will amplify less
14 meaningful deviations towards the end or “tail” of the curve. That is, differences in
15 curve fitting indicators are often the result of data irregularities and do not provide as
16 meaningful an indication of the historical life characteristics. For this reason, if proper
17 care is not taken when interpreting the results, mathematical curve fitting can mislead
18 the analyst into selecting a curve that is not representative of the predominant mortality
19 characteristics of the depreciable group being studied.

1 **Q. Given all of the considerations discussed above, how do you approach the curve**
2 **fitting process?**

3 A. I believe that both mathematical and visual curve fitting should be used. Using both
4 approaches enhances the information available to the analyst and aids in developing the
5 most reasonable forecast. Importantly, the analyst should also understand the
6 advantages and disadvantages of both approaches to avoid being misled by the results.

7
8 **Q. Does the use of judgment also apply to the analysis of historical data curve**
9 **matching process?**

10 A. Yes. There are numerous reasons why informed judgment must also be applied to the
11 mathematical processes of analyzing historical data, including the availability and
12 limitations of the historical data; the interpretation of trends in the data; the
13 interpretation of data irregularities; which data points to include or emphasize in
14 mathematical or visual curve matching; and whether the curve fitting results are
15 reasonable for the types of assets studied. The importance of informed judgment in
16 evaluating the results of statistical analysis is also emphasized by NARUC. For
17 example, when discussing a stub (or incomplete) survivor curve, the NARUC Treatise
18 states:

19 The longer the stub, the more reliable the resulting curve fit
20 and extension. As a result, the analyst may be forced to
21 choose between a more reliable longer stub, which by
22 necessity reflects older data, and a less reliable shorter stub,
23 which reflects more recent vintages and, therefore, is more
24 likely to reflect the future.⁸
25

⁸ NARUC Treatise, p. 129.

1 **Q. Before discussing each account for which OCA witness Garrett has proposed**
2 **changes to your life estimates, address what you perceive as a critical fundamental**
3 **flaw in his analysis?**

4 A Yes. As I explained previously, a service life study was not conducted specifically for
5 this case because it is standard practice in proceedings before this Commission to
6 conduct service life studies on a five-year cycle. Mr. Garrett has performed his life
7 analysis on the basis of service life data through 2022. Therefore, he has not included
8 any transactions that occurred during the period January 1, 2023, through June 30, 2025.
9 If you primarily focus on statistical data, then you should include the most up to date
10 transactional data in your analysis to capture all the factors that affect the life estimation
11 process, which NARUC refers to as the “forces of retirement.” Moreover, if a complete
12 analysis of all the transactional data were to be undertaken, it should be done for all the
13 Company’s accounts, not a curated subset of accounts that, based on Mr. Garrett’s
14 purely statistical analysis, appear not to exhibit the closest “mathematical” fit between
15 an Iowa curve and the OLT for each account. In summary, PPL Electric is entitled to
16 rely on the results of the service life study performed and filed with the Commission in
17 2022, as permitted by the Commission’s regulations. The 2022 service life study was a
18 consistent analysis of all the forces of retirement acting on all the Company’s plant
19 accounts at the time it was performed, and the fact that Mr. Garrett contends that a few
20 discrete plant accounts do not exhibit the closest statistical “fit” between the OLT data
21 and the Iowa curves I used is not an appropriate approach to service life estimation.

1 **C. Account by Account Analysis**

2 **1. Account 356 – Overhead Conductors and Devices**

3 **Q. What service life estimate did you use for this account, and how does it compare to**
4 **the service life estimate Mr. Garrett proposes?**

5 A. This account is not included in the Pennsylvania jurisdictional case. The Company has
6 confirmed that it has not requested recovery of depreciation expense associated with
7 Account 356 in its distribution base rates because Account 356 is a transmission plant
8 account. Effectively, Mr. Garrett proposes an adjustment to the annual depreciation
9 accrual of transmission plant that the Company has not sought to recover as part of its
10 depreciation expense in distribution base rates. Therefore, an adjustment to the
11 Company's depreciation expense based on adjusting the service lives for Account 356
12 should be rejected outright.⁹

13 Notwithstanding, in this section, I address Mr. Garrett's claim because he has
14 challenged the service life from the 2022 service life study. The service life estimate
15 from the Company's last service life study is a 65-R2.5 survivor curve. Mr. Garrett
16 proposes a 73-R2 survivor curve, which would increase the average service life by eight
17 years and the maximum life by 15 years.

⁹ Mr. Garrett shows a total proposed adjustment to the Company's annual accrual for depreciation for the FPFTY of \$8,643,977 (OCA Ex. DJG-17, p. 1). However, because that amount includes Account 356, which is not part of this case, Mr. Garrett's proposed adjustment should total not more than \$4,563,527. Even that proposed adjustment should be rejected for the reasons set forth in this statement.

1 **Q. What reasons does Mr. Garrett give for recommending a longer service life than**
2 **your estimate?**

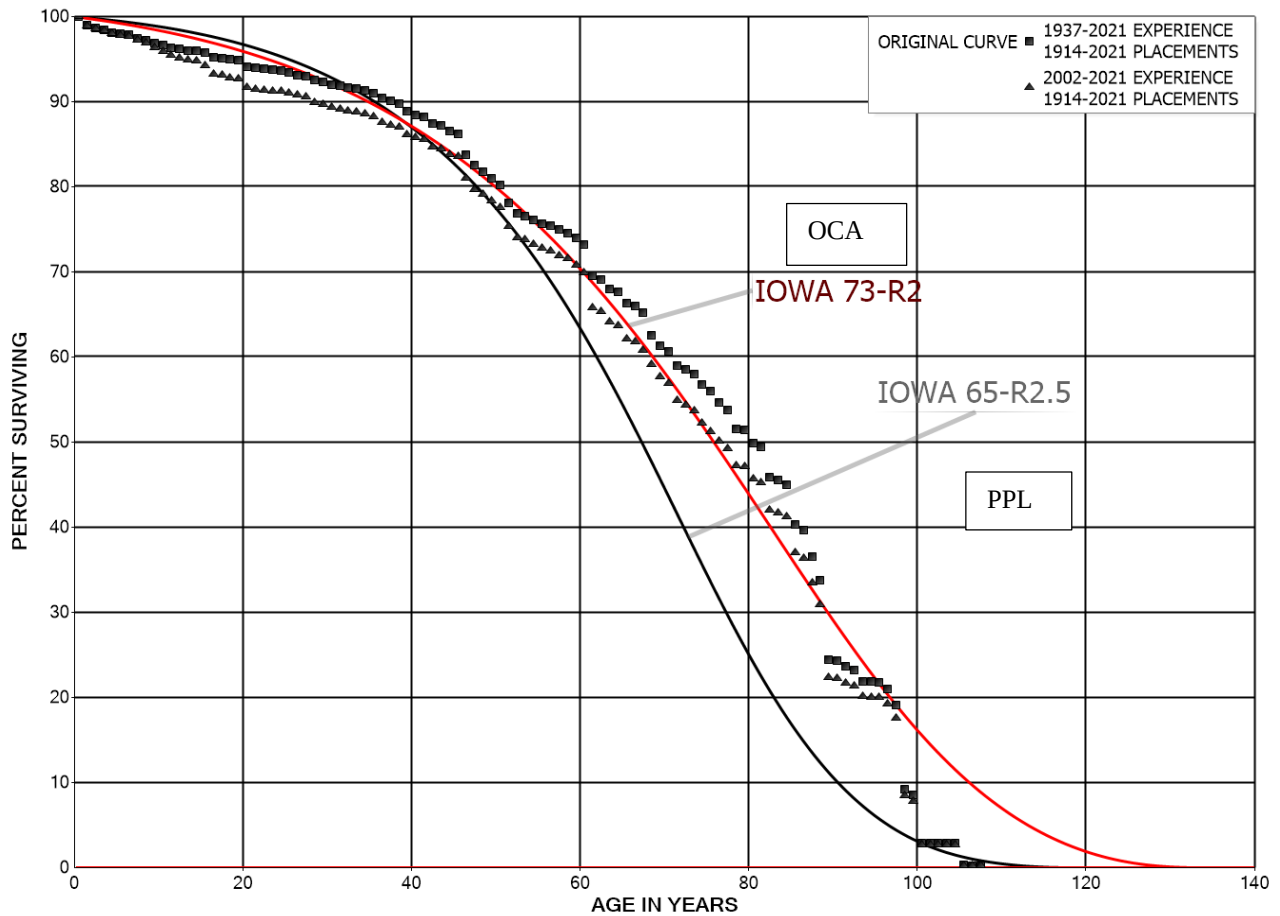
3 A. Mr. Garrett acknowledges in his direct testimony (OCA St. 3, p. 67, lines 4-5) that both
4 his and my survivor curves are reasonable fits to the OLT curve from a visual and
5 mathematical perspective through what he considers the most significant portion of the
6 original life table. Because Mr. Garrett has not updated the transactional data to include
7 a more current estimate, his reliance on mathematical curve-fitting is misguided and
8 inappropriate. Moreover, he does not consider any of the other key factors that need to
9 be assessed in the life estimation process. He does not consider how much of the older
10 conductors and devices will be upgraded due to the need to meet changing load nor does
11 he consider the current estimate, which has been in use by PPL Electric since 2022.
12 Similarly, he does not consider service life estimates used by other electric companies.
13 The survivor curve is a projection of the future. Therefore, any analysis that does not
14 consider elements of growth or the on-going need for the Company to provide reliable,
15 high-quality service under various operating conditions, lacks a proper foundation and
16 should not be adopted. This account has a full life cycle of historical data that shows
17 the maximum life should be less than 110 years, yet Mr. Garrett recommends a curve
18 that has a maximum life as long as 130 years. Additionally, he focuses on the ages of
19 the curve that only represent 76% surviving and does not consider that the older assets
20 will be replaced more frequently than they have in the past due to more recent forces of
21 retirement such as transmission upgrades for load, etc.

22

1 **Q. Please provide reasons why your estimate is more reasonable than that proposed**
2 **by Mr. Garrett.**

3 **A.** Mr. Garrett's proposal appears to be based entirely on the results of mathematical curve
4 fitting. As I discussed previously, relying solely on mathematical curve fitting is not an
5 appropriate way to develop service life estimates particularly when you do not consider
6 what has occurred in the most recent three years. Instead, other factors must be
7 considered. There are two primary factors that support my estimate over that of Mr.
8 Garrett. Mine is the currently approved estimate and is more consistent with the
9 mortality characteristics for the account through the entire life cycle and my estimate is
10 more consistent with estimates for other electric utilities. The data does not support a
11 change in estimate for this account nor is it a reasonable basis to propose a longer service
12 life than is typically used by other utilities. As a result, my estimate is more reasonable
13 than Mr. Garrett's. Figure 2 below compares the life estimate from my Depreciation
14 Study to Mr. Garrett's suggested life estimate.

Figure 2: Account 356, Overhead Conductors and Devices – Comparison of OLT Curve with PPL Electric and OCA Survivor Curve Estimates



2. Account 364.4 – Poles, Towers and Fixtures - Poles

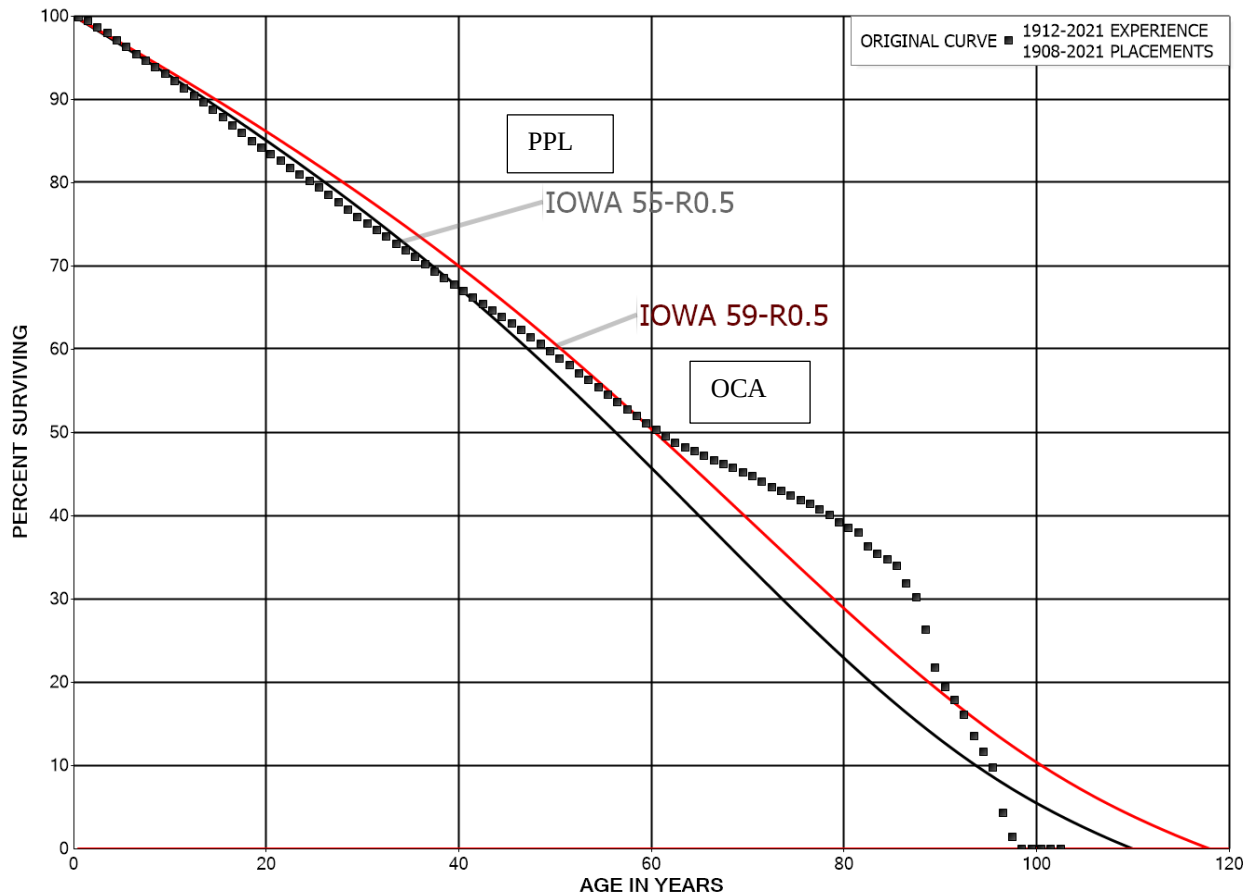
Q. What service life estimate did you use for this account, and how does it compare to the service life estimate Mr. Garrett proposes?

A. The service life estimate from the Company's last service life study is a 55-R0.5 survivor curve. Mr. Garrett proposes a 59-R0.5 survivor curve, which would increase the average service life by four years and the maximum life by 10 years.

1 **Q. Please explain why your estimate is more reasonable than the estimate Mr. Garrett**
2 **proposed.**

3 A. Mr. Garrett's proposal again appears to be based entirely on the results of mathematical
4 curve fitting. However, even if the statistical data were the only basis, Mr. Garrett's
5 estimate does not properly reflect what those data indicate. As shown by data from the
6 OLT, provided in Figure 3, below, all assets that have been exposed to retirement have
7 been retired by about age 100. This indicates that we should not expect assets in this
8 account to last well beyond age 100 when understanding the full life cycle. Mr.
9 Garrett's estimate predicts a full life cycle approximating 118 years, which the data
10 clearly do not support. Maintaining the 55-R0.5 survivor curve takes into consideration
11 the current and future life cycle of this account. As a result, my estimate is more
12 reasonable than Mr. Garrett's. My estimate is a better representation of the first 50 ages
13 in the life table and reflects a more appropriate maximum life.

Figure 3: Account 364.4, Poles, Towers and Fixtures - Poles
OLT Curve with PPL Electric and OCA Survivor Curve Estimates



3. Account 367 – Underground Conductors and Devices

Q. What service life estimate did you use for this account, and how does it compare to the service life estimate Mr. Garrett proposes?

A. The service life estimate from the Company's last service life study is a 56-R2.5 survivor curve. Mr. Garrett proposes a 62-R2 survivor curve, which would increase the average service life by six years and the maximum life by 10 years.

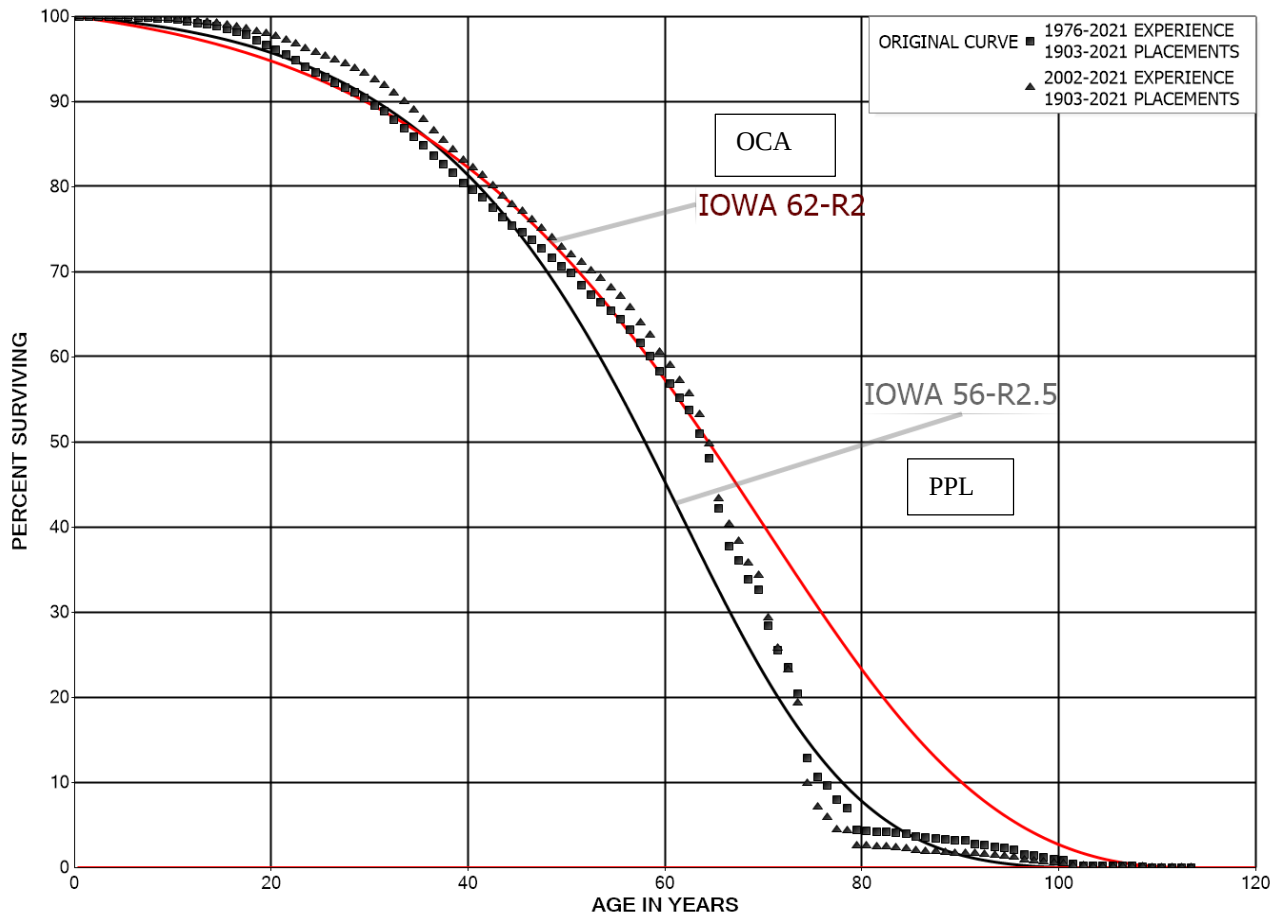
1 **Q. Please explain why your estimate is more reasonable than that proposed by Mr.**
2 **Garrett.**

3 A. Once again, Mr. Garrett's proposal is based entirely on the results of mathematical curve
4 fitting. As discussed previously, relying solely on mathematical curve fitting is not an
5 appropriate way to develop service life estimates. In addition, Mr. Garrett states that
6 his Iowa curve is a better mathematical fit based on the SSD to the observed
7 retirement.¹⁰ However, if you also consider the visual fit and the entire life cycle of an
8 asset class that has a conclusive full life cycle you will see the 56-R2.5 that I select is a
9 better representation than the 62-R2 that Mr. Garrett proposes.

10 Maintaining the 56-R2.5 survivor curve that I have recommended is most
11 appropriate. Figure 4 below compares the life estimate supported in the Depreciation
12 Study compared to Mr. Garrett's suggested life estimate.

¹⁰ OCA St. 3, p. 73, line 7 through p. 8, line 3.

Figure 4: Account 367, Underground Conductors and Devices – Comparison of OLT Curve with PPL Electric and OCA Proposed Survivor Curves



4. Account 366 – Underground Conduit and Account 369.2 - Services

Q. What service life estimates have been recommended for these two accounts?

A. Both of these accounts have inconclusive stub curves. For these accounts, the stub curve only presents a percent surviving that is well over 50 percent so there is not a good indication as to how assets will stay in service through the full life cycle. The current estimate from the last service life study for Account 366 is a 70-R3 survivor curve. Mr. Garrett proposes an 80-R2.5 survivor curve, which would increase the average service life by ten years and the maximum life by 25 years. The current estimate from the last

1 service life study for Account 369.2, is a 60-R2 survivor curve. Mr. Garrett proposes a
2 68-R1.5 survivor curve, which would increase the average service life by eight years
3 and the maximum life by 20 years.
4

5 **Q. What reason does Mr. Garrett offer for proposing such large increases in the**
6 **service lives for these accounts?**

7 A. As with the other accounts that I have discussed, Mr. Garrett again relies only on
8 mathematical curve fitting to support his estimates, which is inappropriate with the stub
9 curves that exist for these accounts because the statistical analysis cannot be definitive
10 for accounts with only stub curves. Mr. Garrett's estimates anticipate that some
11 underground conduit and services (Account 369) will be expected to stay in service for
12 significantly longer than 100 years. And for Account 369 he estimates that some
13 services will survive beyond 120 years. When reviewing other companies that have
14 experience with a full life cycle for these asset classes, it is clear retirements at older
15 ages increase more frequently than what Mr. Garrett estimates. My estimates are within
16 the industry range for underground conduit and services and are more reasonable as
17 compared to the large increases Mr. Garrett proposes for these accounts. Figures 5 and
18 6 below compare the life estimates supported in the Depreciation Study to Mr. Garrett's
19 suggested life estimates.
20

**Figure 5: Account 366, Underground Conduit– Comparison of OLT Curve with
PPL Electric and OCA Proposed Survivor Curves**

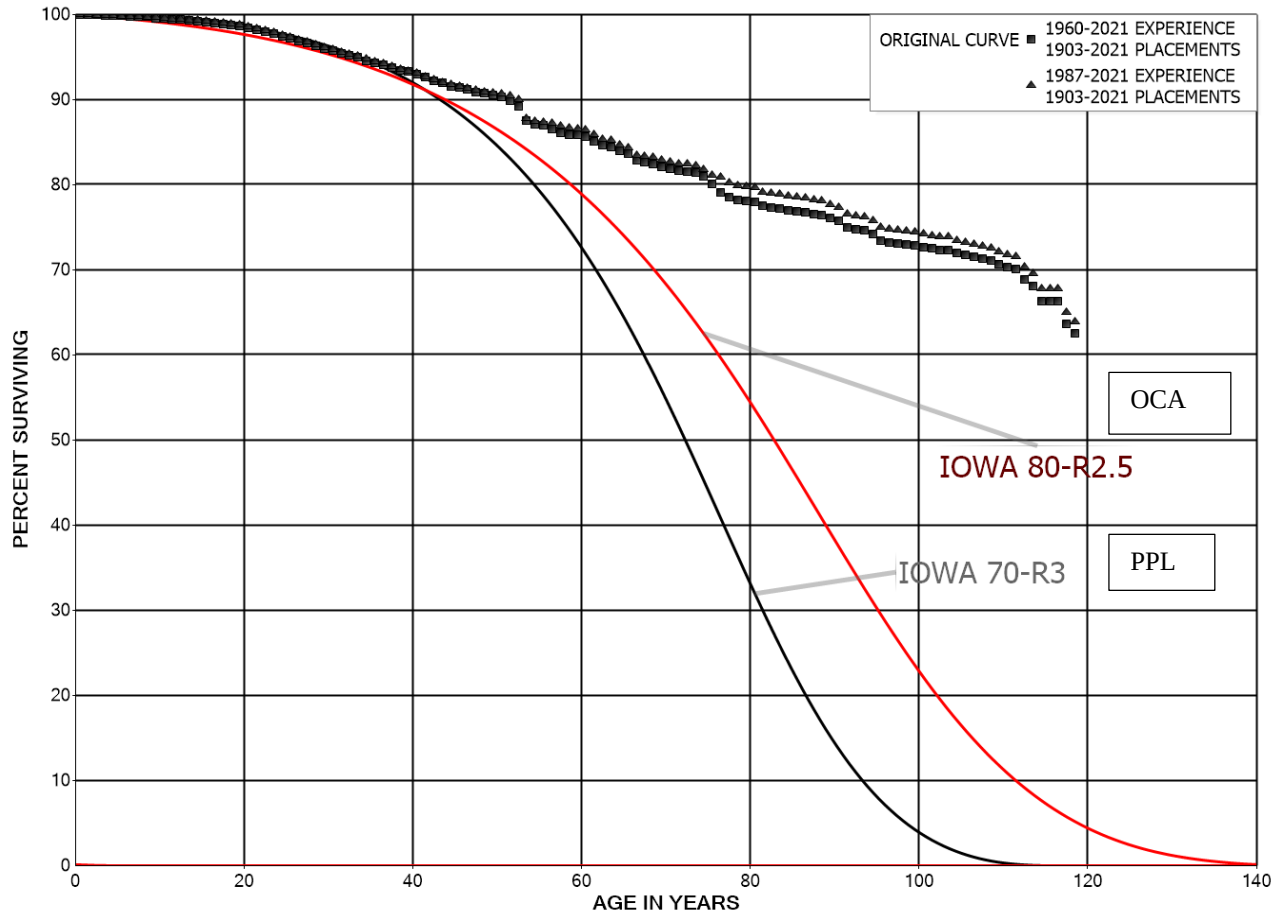
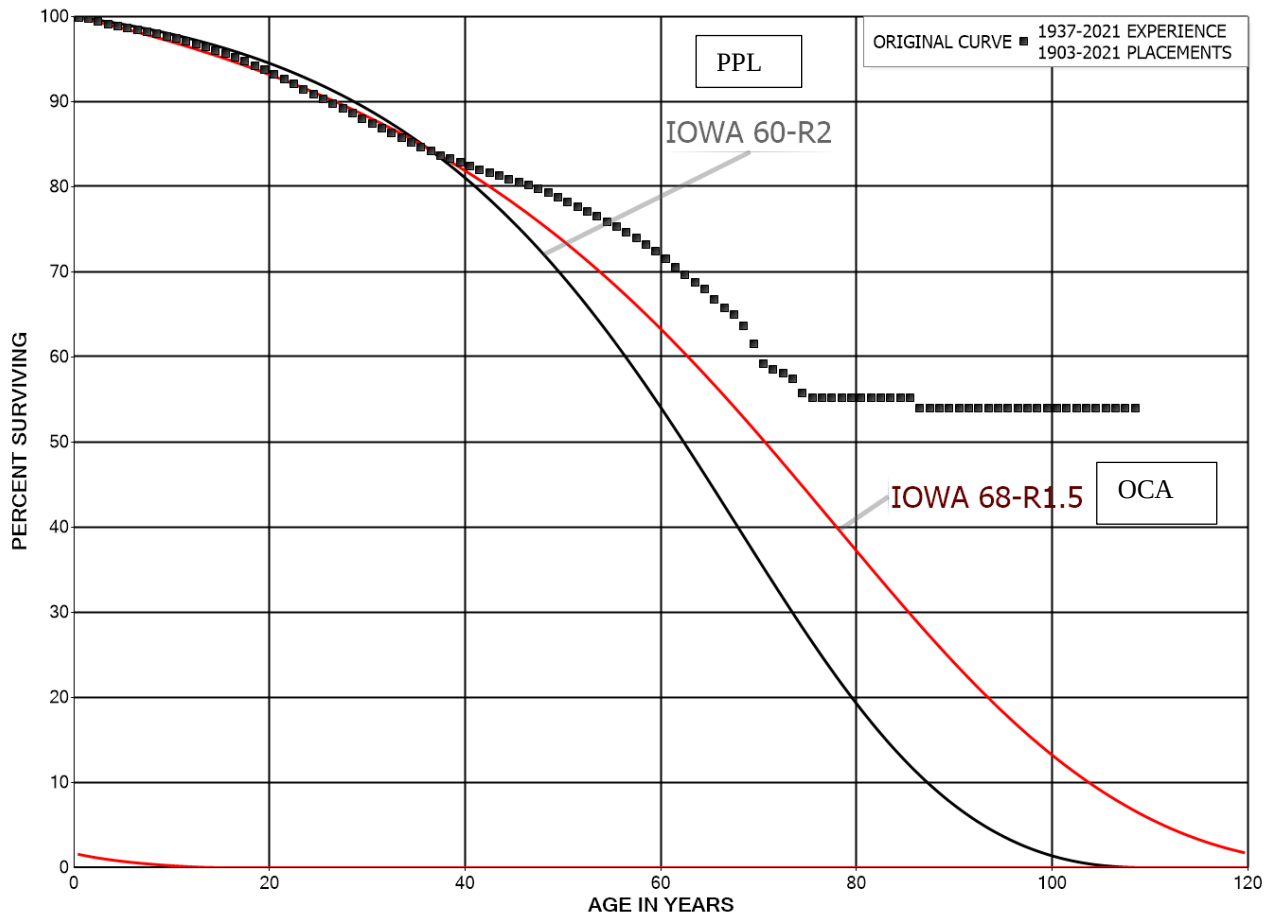


**Figure 6: Account 369, Services– Comparison of OLT Curve with
PPL Electric and OCA Proposed Survivor Curves**



IV. DEVELOPMENT OF THE FORECASTED BOOK RESERVE

Q. Has OCA witness Garrett properly calculated the book reserve for the FTY and FPFTY for the accounts he for which he proposes changing the survivor curve?

A. No. Revising the estimated survivor curve for an account requires that the projected bring-forward of the book reserve be revised as well. Mr. Garrett has not properly accounted for the changes he has proposed to survivor curves because he continues to use a projected bring-forward of the book reserve that is based on the survivor curve estimates from PPL Electric's 2022 service life study rather than his revised estimates.

1
2 **Q. What is the appropriate process for calculating the proposed depreciation expense**
3 **and annual depreciation accrual rates for purposes of a Pennsylvania rate case?**

4 A. Pennsylvania authorizes the calculation of proposed depreciation expense and annual
5 depreciation accrual rates as of the end of a FPFTY. In this case, the FPFTY ends June
6 30, 2027, and the Company is relying principally on the FPFTY data to support its
7 proposed revenue increase.
8

9 **Q. Please explain how the FPFTY levels of plant and accumulated depreciation (or**
10 **“reserve”) are developed?**

11 A. The process begins with the calculation of depreciation expense and annual depreciation
12 accrual rates as of a HTY, which is completed using historical, or actual, levels of plant
13 and book reserve. In this case, the HTY ends June 30, 2025. Once depreciation expense
14 and annual depreciation accrual rates are calculated as of the end of the HTY, those
15 amounts are used, along with projected levels of plant activity, to develop the plant
16 values and bring-forward of the reserve to the end of the FTY, at which point the levels
17 of depreciation expense and annual depreciation accrual rates are calculated again. In
18 this case, the end of the FTY is June 30, 2026. The final step in calculating the proposed
19 depreciation expense and annual depreciation accrual rates is to use the FTY
20 depreciation expense and annual depreciation accrual rates along with projected levels
21 of plant activity to develop the plant values and to bring-forward the reserve to the end
22 of the FPFTY, at which point the proposed levels of depreciation expense and annual

1 depreciation rates are calculated for the FPFTY. In this case, the end of the FPFTY is
2 June 30, 2027.

3
4 **Q. Is it important to use a consistent procedure throughout the process of developing**
5 **the annual and accumulated depreciation, as you described above?**

6 A. Yes, it is. Using consistent procedures avoids the possibility that the bring-forward of
7 the book reserve will fail to match the annual accruals for depreciation. What Mr.
8 Garrett proposes (reducing the FTY and FPFTY annual accruals for depreciation while
9 leaving the book reserve amounts the same as the Company has proposed) would, if
10 adopted, overstate the bring-forward of the book reserve and, therefore, understate rate
11 base.

12
13 **Q. Has Mr. Garrett followed the process applied in Pennsylvania when calculating his**
14 **proposed levels of depreciation expense and annual depreciation accrual rates?**

15 A. No, not for the five accounts for which he proposed different service lives.

16
17 **Q. Please describe how Mr. Garrett has deviated from the applicable Pennsylvania**
18 **process.**

19 A. Mr. Garrett proposes using the same book reserve I developed in my depreciation
20 studies, despite the fact he has changed the life characteristics for five plant accounts by
21 substantially lengthening their proposed service lives.

22

1 **Q. Why is Mr. Garrett's proposal not appropriate?**

2 A. Given that OCA witness Garrett has proposed different survivor curves for five plant
3 accounts, the book reserve associated with each of those accounts should also change to
4 conform to the changed lives he recommends. Because he has proposed longer average
5 service lives for each of those five plant accounts, the bring-forward of the book reserve
6 would be lower than the amounts presented in PPL Electric Exhibits JJS-2 and JJS-3.
7 Additionally, the annual depreciation expense that he claims would have to be higher
8 due to the higher rate base that would result if Mr. Garrett's proposed service lives were
9 adopted. Using Mr. Garrett's revised service life estimates, the total book reserve as of
10 June 30, 2027, would be \$4,721,281,351 for all depreciable plant, which is
11 approximately \$20 million less than what was in PPL Electric Exhibit JJS-3 for all plant
12 accounts. Therefore, in Mr. Garrett's workpapers developing his proposed adjustments
13 he would have to reflect the need to collect \$20 million more than he has proposed for
14 all depreciable plant. The additional \$20 million would need to be recovered over the
15 remaining life of each of the accounts for which he proposed increasing the service lives.

16
17 **V. CONCLUSION**

18 **Q. Is there anything in the testimony of the OCA witness that should influence the**
19 **commission to accept his depreciation recommendations?**

20 A. No. As I have previously explained, PPL Electric's proposed depreciation rates were
21 prepared in accordance with current precedent and practice before the Commission.
22 OCA witness Garrett has incorrectly calculated depreciation rates for the FTY and
23 FPFTY and developed unreasonable life characteristics for the five accounts for which

1 he proposes longer service lives. The Commission should approve the depreciation
2 rates set forth the Company's filing after correcting the annual accrual amounts to
3 properly reflect the inclusion of net salvage that was inadvertently omitted from the
4 Company's original filing.

5

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

7 **A. Yes, it does.**

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
ANDREW ELMORE
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Payroll Taxes and Expenses**
 PURTA Tax
 Interest Synchronization
 Gross Receipts Tax

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Andrew W. Elmore. My business address is 645 Hamilton Street, Allentown,
4 PA.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed as Vice President – Tax by PPL Corporation (“PPL Corp.”), which is the
8 parent company of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”).

9
10 **Q. Have you previously filed testimony in this matter?**

11 A. Yes, I filed direct testimony at PPL Electric Statement No. 12.

12
13 **Q. What is the purpose of your rebuttal testimony?**

14 A. The purpose of my rebuttal testimony is to respond to concerns and recommendations made
15 by the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation
16 and Enforcement (“I&E”) and the Office of Consumer Advocate (“OCA”) regarding tax
17 issues. Specifically, I address testimony regarding payroll taxes and expenses, the Public
18 Utility Realty Tax Act (“PURTA”) tax, interest synchronization, and gross receipts tax from
19 I&E Witness Keller and OCA Witness Morgan.

1 **Q. Please summarize the key issues and recommendations offered by the opposing**
2 **witnesses that you address in your rebuttal testimony.**

3 A. The first issue raised by both the I&E and OCA witnesses regards the appropriate payroll
4 withholding tax rate to be utilized by PPL Electric in its rate filing. Both of these witnesses
5 suggest that the appropriate payroll withholding tax rate should be 7.65% and not the 8.5%
6 utilized by the Company. The second issue raised by the OCA witness concerns the
7 appropriate amount of tax to be recovered under PURTA. The witness suggests that the
8 PURTA tax rate is 0% and a corollary adjustment of \$1,410,000. Finally, the last tax issue
9 raised by OCA Witness Morgan concerns interest synchronization and the appropriate amount
10 of forecasted tax deductible interest expense. This witness suggests that tax deductible interest
11 should be increased by \$41,802,000. In turn, this would result in decreases of state and federal
12 income taxes by \$3,026,000 and \$8,143,000, respectively.

13
14 **Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?**

15 A. I am sponsoring or co-sponsoring Schedules B-5, D-17, and D-18 of PPL Electric Rebuttal
16 Exhibit No. 1.

17
18 **II. PAYROLL TAXES AND EXPENSES**

19 **Q. What allowance does I&E Witness Keller recommend for the Company's payroll taxes?**

20 A. He recommends "an allowance of \$4,593,000 for payroll taxes, or a reduction of \$2,368,000
21 (\$6,961,000 - \$4,593,000) to the Company's claim" for the FPFTY from the initial filing.
22 (I&E St. No. 2, p. 11.)

1
2 **Q. What is the basis for this recommendation?**

3 A. He claims that his recommendation is “based on utilizing a payroll tax rate of 7.65% and the
4 recognition of the payroll expense reduction from [his] vacancy adjustment, and on the
5 percentage of total payroll taxes to total payroll.” (I&E St. No. 2, p. 11.) According to Mr.
6 Keller, “[t]he Company’s 8.5% claim for total payroll taxes is unsupported, particularly since
7 the combination of Social Security and Medicare taxes should be 7.65%, and not the 8.0%
8 total that PPL has indicated.” (I&E St. No. 2, p. 11.) Additionally, Mr. Keller “disagree[s]
9 with including employee benefits in the computation for payroll taxes.” (I&E St. No. 2, p. 11.)
10 He also states that the cap of earnings on Social Security income is \$184,500 for 2026 and
11 that the number of employees will exceed the earnings subject to the Social Security tax, so
12 his proposed 7.65% is reasonable and should account for any employer share of state and
13 federal unemployment taxes. (I&E St. No. 2, p. 12.)
14

15 **Q. Do you agree with Mr. Keller’s proposed allowance for payroll taxes?**

16 A. Solely for purposes of this rate case filing, PPL Electric is willing to accept Mr. Keller’s
17 proposed adjustment. Nevertheless, Mr. Keller does concede that there are additional payroll
18 taxes that are borne by the Company, such as federal and state unemployment taxes. (See
19 I&E St. No. 2, p. 12.) While the wage bases for these taxes are as Mr. Keller suggests, these
20 taxes are still a very real cost for the Company and should not be ignored. In addition, while
21 Mr. Keller correctly notes that there is a cap on Federal Insurance Contributions Act (“FICA”)
22 withholding (i.e., \$184,500 of income), the vast majority of the Company’s employees will

1 not meet or exceed this threshold. Therefore, the Company disagrees with Mr. Keller's
2 suggestion that FICA withholding cap will apply to a material percentage of employees'
3 income.

4
5 **Q. Does OCA Witness Morgan address PPL Electric's payroll expenses?**

6 A. Yes. Mr. Morgan disagrees with PPL Electric's use of 8% for the Social Security/Medicare
7 taxes in its calculation of the payroll increase because, according to him, "the Social
8 Security/Medicare taxes remain the same for variable pay." (OCA St. 1, pp. 8-9.)

9
10 **Q. Does Mr. Morgan make any adjustments to payroll taxes?**

11 A. Yes. Mr. Morgan uses a revised tax rate to reflect an alleged actual combined rate of 7.65%,
12 which, when combined with the adjustment to the 12 employees, decreases labor expenses by
13 \$747,000 (see OCA Exhibit LKM-4).

14
15 **Q. Please respond to this adjustment.**

16 A. As discussed above, regarding Mr. Keller's recommendation, solely for purposes of this rate
17 case filing, the Company is willing to accept the utilization of the 7.65% payroll withholding
18 percentage but does not agree with Mr. Morgan's adjustment regarding a decrease in labor
19 expenses.

20

1 **III. PURTA TAX**

2 **Q. Does OCA Witness Morgan make a recommendation regarding the PURTA expense?**

3 A. Yes, he recommends a \$1,410,000 downward adjustment in PURTA expense because he
4 asserts that there will be no PURTA expenses in 2025 and 2026. (OCA St. 1, p. 20.)
5

6 **Q. Do you agree with this recommendation?**

7 A. No.
8

9 **Q. Why not?**

10 A. Mr. Morgan appears to be confusing the foundational PURTA tax with the PURTA surcharge.
11 Although the millage rate for the PURTA surcharge for 2025 is 0%, that does not mean that
12 the foundational PURTA millage rate for 2025 will be 0. The foundational PURTA millage
13 rate for 2025 will not be published until August 2026. As a point of reference, however, the
14 PURTA millage rates for the 5 years prior to 2025 were as follows:

- 15 • 2020 - 0.0278851
- 16 • 2021 - 0.0268399
- 17 • 2022 - 0.0248751
- 18 • 2023 - 0.02238315
- 19 • 2024 - 0.0233189

20 For purposes of the current distribution base rate case filing, the Company utilized the
21 latest millage rate for calculating the PURTA liability. That millage rate is the second
22 lowest one out of the past 5 years, so the Company's reliance on that figure is conservative.
23 At the very least, however, it is wholly unreasonable for Mr. Morgan to claim that the
24 PURTA millage rate will be 0. I further note that the rate is trued up in the 4th quarter of

1 each year in the annual State Tax Adjustment Surcharge (“STAS”) filing. Therefore, if
2 the millage rate for 2025 turns out to be lower than the rate for 2024, customers will see
3 that reduction flow through their rates via the STAS. For these reasons, Mr. Morgan’s
4 recommended disallowance should be denied.

5
6 **IV. INTEREST SYNCHRONIZATION**

7 **Q. Does OCA Witness Morgan take a position on interest synchronization?**

8 A. Yes, he recommends a decrease in state and federal income taxes of \$3,026,000 and
9 \$8,143,000, respectively, based on the interest synchronization that reflects OCA’s
10 recommended rate base and weighted cost of debt. (OCA St. 1, pp. 25-26.)

11
12 **Q. Do you agree with this recommendation?**

13 A. No.

14
15 **Q. Why not?**

16 A. PPL Electric disagrees with the OCA’s weighted cost of debt for the reasons set forth in the
17 rebuttal testimony of PPL Electric Witnesses Nelson (PPL Electric St. No. 10-R) and Burgos
18 (PPL Electric St. No. 9-R). Further, the Company likewise disagrees with OCA’s proposed
19 adjustments to PPL Electric’s rate base as described in the rebuttal testimony of PPL Electric
20 Witnesses Spanos (PPL Electric St. No. 11-R) and Arnold (PPL Electric St. No. 13-R). As
21 such, I disagree with Mr. Morgan’s interest synchronization adjustment that decreases the
22 Company’s state and federal income taxes. For a further discussion on interest

1 synchronization, please see PPL Electric Witness Dane's rebuttal testimony (PPL Electric St.
2 No. 6-R).

3
4 **V. GROSS RECEIPT TAXES**

5 **Q. Does the Company propose any changes to its Gross Receipts Tax ("GRT") gross-up**
6 **value?**

7 A. Yes. The Company identified that its gross-up for GRT did not account for the corresponding
8 gross-up in uncollectible expense that is anticipated to result from its requested revenue
9 increase. I&E Witness Walker makes this adjustment in his proposed revenue requirement.
10 The Company agrees with this adjustment and has reflected the change in its updated revenue
11 requirement calculation provided in the PPL Electric Witness Dane's rebuttal testimony (PPL
12 Electric St. No. 6-R).

13
14 **VI. CONCLUSION**

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

16 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
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Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
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Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
KATELYN ARNOLD
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Storm Damage Expenses**
 Cash Working Capital
 Eligible Customer List Expenses

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Katelyn Arnold. My business address is 827 Hausman Road, Allentown, PA 18104-9392.

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

A. I am employed by PPL Services Corporation, a subsidiary of PPL Corporation (“PPL Corp.”) and an affiliate of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”) as Manager – Regulatory Strategy and Rates.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted my direct testimony, PPL Electric Statement No. 13.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to portions of the direct testimony submitted by the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation and Enforcement (“I&E”) Witnesses Walker and Keller, Office of Consumer Advocate (“OCA”) Witnesses Morgan and Koenig, Office of Small Business Advocate (“OSBA”) Witness Ewen, and Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (“CAUSE-PA”) Witness Cicero. Specifically, I address claims about the Company’s Storm Damage Expenses, Cash Working Capital, and Eligible Customer List Expenses.

Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?

A. Yes. I have attached PPL Electric Exhibits KEA-1R through KEA-4R. I am also sponsoring or co-sponsoring Schedules C-4 and D-8 in PPL Electric Rebuttal Exhibit No. 1, which is attached to Ms. Bethany Johnson's rebuttal testimony (PPL Electric St. No. 5-R).

Q. How is the remainder of your rebuttal testimony organized?

A. I will first address the witnesses' claims related to the Company's recovery of Storm Damage Expenses. Secondly, I will respond to the proposals related to PPL Electric's Cash Working Capital calculation. Finally, I will answer OCA Witness Morgan's position on Eligible Customer List Expenses.

Q. Before addressing the other parties' direct testimony in detail, do you have any corrections to the Company's initial rate case filing that you would like to discuss?

A. Yes. As outlined in the PPL Electric Statement No. 2-R, the Company presented an updated revenue requirement calculation, which is attached to PPL Electric Witness Urban's rebuttal testimony (PPL Electric St. No. 2-R) as PPL Electric Exhibits DAU-1R and DAU-2R. This update includes four adjustments, one of which is an adjustment to the Company's cash working capital calculation based on a change to the Historic Test Year ("HTY") Schedule D-1, which impacted the calculation of the average lag in days between payment of operation and maintenance ("O&M") expenses and receipt of revenue value that flowed

1 through to the Future Test Year (“FTY”) and the Fully Projected Future Test Year
2 (“FPFTY”). This is further explained in the discovery response to I&E-RE-I-2-D, attached
3 to Mr. Urban’s rebuttal testimony as PPL Electric Exhibit DAU-3R.
4

5 **II. STORM DAMAGE EXPENSES**

6 **Q. Does the Company wish to clarify the mechanics of its Storm Damage Expense Rider**
7 **(“SDER”)?**

8 A. Yes. At a high level, the current SDER mechanism allows for the recovery of eligible
9 storm expenses, the criteria for which is outlined in its tariff, attributable to Commission
10 reportable storms when those costs exceed the amount of storm damage expense recovered
11 through the Company’s base distribution rates. As an illustrative example, I have attached
12 the Company’s most recent SDER rate filing for rates effective January 1, 2026, through
13 December 31, 2026, as PPL Electric Exhibit KEA-1R. As shown on page 2, line 5, Column
14 E of that exhibit, during the period of November 1, 2024, and October 31, 2025, the
15 Company incurred \$57,501,306 in eligible storm damage expenses, including interest (see
16 line 3) and the annual amortization of expenses related to two extraordinary storm events
17 (see line 4). The Company currently has \$20,024,000 in total storm expenses in its
18 distribution base rates. (See PPL Electric St. No. 13, pp. 9-10; PPL Electric Exhibit KEA-
19 1R, p. 2, line 6, Column E). The SDER mechanism is designed such that the amount
20 recovered through base rates (the \$20,024,000 noted above) is applied to the amount of the
21 eligible storm damage expenses incurred, which leaves \$37,477,306 remaining for
22 recovery through the SDER (excluding prior year over/under reconciliation amounts).

1 With an under-collection balance of \$1,911,805 (see PPL Electric Exhibit KEA-1R, p. 2,
2 line 7, Column E), the Company had a total of \$39,389,111 (see PPL Electric Exhibit KEA-
3 2, p. 2, line 8, Column E) in storm damage expenses to be recovered through the SDER.

4 However, there is a cap on the amount of revenue that can be recovered through the
5 SDER. Specifically, the amount of storm damage expense that can be recovered through
6 the SDER cannot exceed 3% of the total intrastate operating revenues billed to customers,
7 exclusive of amounts recovered under the State Tax Adjustment Surcharge (“STAS”). This
8 “cap” on SDER recovery is calculated each year by taking 3% of the Company’s forecasted
9 distribution revenue (including base distribution and distribution rider revenue) for the year
10 using the revenue forecast utilized in the SDER rate filing. In 2025, the cap was
11 \$37,193,987 (see PPL Electric Exhibit KEA-1R, p. 2, line 9, Column E). As a result, the
12 Company could only recover \$37,193,987 through its SDER (see PPL Electric Exhibit
13 KEA-1R, p. 1, line 1 Column E), with the remaining \$2,195,124 of storm damage expenses
14 being deferred and made available for recovery in the Company’s next base rate case under
15 Section 1308 (see PPL Electric Exhibit KEA-1R, p. 2, line 10, Column E), per the SDER
16 Tariff.

17
18 **Q. Are costs resulting from major storm events recoverable through the SDER?**

19 A. Costs from major storm events, defined as an interruption of electric service resulting from
20 conditions beyond the control of the Company which affect at least 10% of the Company’s
21 customers during the course of the event for a duration of 5 minutes each or greater (see
22 52 Pa. Code §57.192), are recovered in the SDER, plus interest, over three years and

1 reflected in SDER rates commencing in the application year after the storm occurred, as
2 approved in the Commission's Order entered April 3, 2014, at Docket No. R-2012-
3 2290597 ("April 2014 Order").
4

5 **Q. Are costs resulting from extraordinary events recoverable through the SDER?**

6 A. Yes. As defined in the Commission's April 2014 Order, a storm event with storm damage
7 expenses exceeding 5% of the Company's annual distribution net income is considered
8 "extraordinary" for SDER recovery purposes. Further, as outlined in the Commission's
9 April 2014 Order, eligible storm damage expenses resulting from extraordinary events are
10 amortized over three years and recovered through the SDER, similar to major storm events.
11 I also note that under Paragraphs 21 and 37 of the Commission-approved 2015 Rate Case
12 Settlement, PPL Electric received approval to amortize approximately \$5.3 million of
13 expenses related to extraordinary storms from 2011 in its base rates through December
14 2017, at which point, beginning January 1, 2018, the amortized storm expense of
15 approximately \$5.3 million would be included in the base rate component of the SDER. In
16 this case, the Company is not proposing to include amortized expenses related to
17 extraordinary storms in its base rates. However, the Company does propose to continue
18 amortizing both major storm events and extraordinary storm expenses over three years for
19 recovery through its SDER.
20

21 **Q. Is the Company currently amortizing expenses related to extraordinary storm**
22 **events?**

1 A. Yes, as discussed in my direct testimony, the Company began amortizing costs from a
2 February 2024 storm through its 2025 SDER rate (PPL Electric St. No. 13, p. 14) and will
3 continue to recover those costs through the 2026 and 2027 SDER rate periods. The
4 Company has also begun recovering costs associated with a November 2024 storm in its
5 2026 SDER rate and will continue to recover those costs in the 2027 and 2028 SDER rate
6 period. To be clear, these costs are not recovered through base rates. They are only
7 recovered through the SDER charge. The Company intends to continue amortizing these
8 storms through its SDER rate after the date of new rates effective in this base rate case. As
9 such, the SDER rate on July 1, 2026, will not be exactly zero; however, the rate will be
10 reset to reflect the new level of storm damage expense recovered in base distribution rates
11 (i.e., the equivalent of the \$20,024,000 discussed above or the \$32,000,000 in reportable
12 storms proposed in this instant proceeding, assuming the Company's storm damage
13 expense claim is approved).

14 Of note, since the submission of my direct testimony, the Company has identified
15 an adjustment to the total cost of the November 2024 extraordinary storm event. I
16 previously stated that this storm resulted in costs of \$20,700,346. Based on updated
17 accounting information, the Company wishes to revise this amount to be \$20,683,748.41,
18 a decrease of \$16,597.59, in eligible storm damage expenses from the November 2024
19 storm to be recovered in the SDER.

20

1 **Q. Is the \$20,024,000 in current base distribution rates related only to expenses resulting**
2 **from Commission reportable storms?**

3 A. No, the \$20,024,000 of storm expense in current base rates represents \$14,700,000 for
4 Commission reportable storms as well as the approximately \$5.3 million associated with
5 the amortization of extraordinary storms as approved in the Company's 2015 distribution
6 base rate case. This is consistent with the terms of the 2015 Rate Case Settlement,
7 including I&E Witness Lisa A. Boyd's direct testimony from that proceeding, in which she
8 recommended that "any continued recovery" of the "claimed amortization expense of
9 \$5,342,000" beyond "2017 be included in the base rate SDER ratepayer contribution
10 beginning in 2018, if the Company has not filed for a base rate case, in order to remove the
11 storm amortization expense from base rates." (I&E St. No. 2 (2015 Rate Case), p. 38.) In
12 support of her recommendation, she explained the net effect of adding this amortization
13 expense to the SDER in 2018 as follows:

14 The Company proposes to maintain the original designated
15 base rate annual storm expense of \$14,700,000 to be offset
16 against actual storm costs when the SDER is reconciled
17 annually (Company Statement No. 4, p. 21). In 2018,
18 inclusion of the expired storm amortization expense would
19 increase the base rate annual storm expense to \$20,024,000
20 (\$14,700,000 + \$5,324,000). The base rate amount of
21 \$20,024,000 would then be used as the ratepayer
22 contribution to be offset against actual storm costs when the
23 SDER is reconciled. The Company can adjust the base rate
24 storm expense of \$20,024,000 relative to the actual storm
25 experience and SDER history in its next base rate case.

26 (*Id.*, pp. 38-39.) Copies of the relevant portions of Ms. Boyd's direct testimony from that
27 proceeding are attached as PPL Electric Exhibit KEA-4R.

1 **Q. How does I&E Witness Walker summarize the Company’s Storm Damage Expense**
2 **and SDER proposals?**

3 A. He notes that the Company is proposing, “(1) to increase the baseline for Commission-
4 reportable storm damage expenses included in the Storm Damage Expense Rider (SDER)
5 to \$32,000,000; (2) to recover a regulatory asset through a three-year amortization of
6 \$11,336,000, or \$3,779,000 ($\$11,336,000 \div 3$ years) annually, for SDER-eligible storm
7 costs incurred in excess of the SDER cap; (3) to modify the SDER mechanism to recover
8 an additional \$10,500,000 for expenses related to non-reportable storms that were
9 previously recovered through base rates; and (4) to recover deferred expenses of
10 \$12,366,000, or \$4,122,000 ($\$12,366,000 \div 3$ years) annually, related to an extraordinary
11 storm in February 2024.” (I&E St. No. 1, pp. 11-12.) He also notes that “PPL Electric is
12 proposing to establish a new baseline of \$42,500,000 for the SDER to be recovered in base
13 rates” and that “[t]he proposed new SDER baseline includes \$32,000,000 for Commission-
14 reportable storm damage expenses and \$10,500,000 for non-reportable storm damage
15 expenses.” (I&E St. No. 1, p. 12.)

16
17 **Q. What does Mr. Walker recommend?**

18 A. He recommends that the Commission deny PPL Electric’s proposal to include non-
19 reportable storm-related expenses of \$10.5 million in the SDER, arguing that those
20 expenses should continue to be recovered in base rates. (I&E St. No. 1, pp. 12-13.) He
21 also recommends that PPL Electric clarify the language in its tariff regarding a mandatory
22 3-year recovery period for major storms to “accurately indicate that this recovery period

1 only applies to storms recovered via the SDER and not residual balances when the SDER
2 resets to zero at a base rate proceeding.” (I&E St. No. 1, p. 13.) According to Mr. Walker,
3 “[u]sing the three-year amortization period subsequent to the last base rate case in 2015
4 resulted in the Company recovering fully amortized amounts in base rates for a minimum
5 of seven years beyond full amortization.” (I&E St. No. 1, p. 13.) He also proposes that the
6 Commission use the historical filing frequency of PPL Electric’s base rate cases to
7 determine the appropriate amortization period, thus leading to a “recovery of the
8 \$11,336,000 expenses over the SDER cap.” (I&E St. No. 1, p. 13.) Based on that amount,
9 he proposes an annual amortization amount of \$2,230,000 (i.e., $(\$11,336,000 / 61 \text{ months})$
10 $\times 12 \text{ months}$). (I&E St. No. 1, p. 13.)

11 Similarly, Mr. Walker recommends an adjustment to the unamortized expense
12 balance from the 2024 storm consistent using the historical filing frequency, too, which
13 results in a recommended annual amortization amount of \$1,622,000. (I&E St. No. 1, p.
14 14.) He also proposes that the total SDER baseline be calculated using the sum of the
15 three-year historical average expense of \$18,154,000 plus the \$2,230,000 and \$1,622,000
16 annual amortizations, thus capping the reportable storm expenses included in the SDER at
17 \$22,006,000. (I&E St. No. 1, p. 15.)

18 Finally, Mr. Walker recommends a storm damage expense allowance of
19 \$32,506,000 (i.e., sum of \$22,006,000 reportable storm expense allowance and
20 \$10,500,000 non-reportable storm expenses) to be recovered through base rates, which
21 equals a \$9,994,000 reduction in the FPFTY storm damage expense claim. (I&E St. No.
22 1, p. 15.)

Q. What is Mr. Walker’s purported justification for these recommendations?

A. He argues that: (1) SDER was “never intended to provide guaranteed dollar-for-dollar recovery of all storm expenses”; (2) PPL Electric is not precluded from “seeking recovery of Commission-reportable storm damage expenses that exceed the cap in future rate cases”; and (3) PPL Electric witness Lookup testified that the Company is proactively hardening the distribution system, so “the magnitude of the Company’s projected increase is unreasonable.” (I&E St. No. 1, p. 15-16.) He also says that his argument for the use of the historic filing frequency to determine the amortization period does not violate the SDER requirements. (I&E St. No. 1, p. 17.)

Q. Do you agree with Mr. Walker that the Commission should deny the Company’s proposal to include non-reportable storm-related expenses of \$10.5 million in the SDER?

A. No. In its April 2014 Order, the Commission stated: “We find that implementation of a SDER will work to provide timely revenue recovery such that PPL will have adequate resources to respond to powerful weather events, and will facilitate more gradual changes in rates in the future.” April 2014 Order, p. 23. Although the SDER was established in the aftermath of extreme weather events, the benefits identified by the Commission in its April 2014 Order—timely revenue recovery to fund adequate storm response and gradual rate changes—are not limited to Commission reportable storms. Particularly in an environment where the Company is seeing more frequent storms, the ability to recover costs for these

1 non-reportable storms is even more vital. The Company experienced 39 non-reportable
2 storm events in 2025, 20 in 2024, and 31 in 2023, with the historic prior 10-year average
3 of 21. The sheer volatility of the number of non-reportable storms and the expenses
4 associated with them warrant the addition of this expense category to the SDER.
5 Additionally, making these non-reportable storm costs eligible for the rider ensures that
6 customers pay only for actual costs incurred, no more and no less.

7
8 **Q. Do you agree with Mr. Walker's claim that the Company's projected increase is**
9 **unreasonable?**

10 A. No. Mr. Walker states that the amount of the increase is unreasonable because the
11 Company is investing in hardening its system. However, this is precisely why the
12 Company needs the ability to recover the expenses associated with non-reportable storms
13 through SDER as well as Commission reportable storms. While the Company is investing
14 heavily in resiliency projects, these capital improvements do not eliminate storm damage
15 expense. Hardening reduces risk and outage duration, but it does not eliminate the need
16 for ongoing reactive storm restoration.

17 Even as the system becomes stronger, the volume of storms—especially
18 non-reportable ones—has increased, and regulatory recovery mechanisms should adapt
19 accordingly. The SDER provides the correct structure to reflect this reality. With a more
20 hardened system, it is reasonable to expect fewer storms to hit the Commission's reportable
21 storm threshold. Without the ability to recover non-reportable storms through SDER, if
22 the Company incurs significantly more non-reportable storm expense than the amount

1 included in base rates, it will not be able to recover those amounts. At the same time, if
2 the Company's storm hardening efforts reduce the storm damage expenses for reportable
3 storms as Mr. Walker posits, then the Company would be simultaneously refunding
4 customers for costs not incurred for reportable storms under the base rate amount. Thus,
5 by limiting cost recovery through the SDER to Commission reportable storms only, the
6 Company would be financially disadvantaged by hardening its system and reducing the
7 impact of storms.

8
9 **Q. Do you agree with the recommendation to clarify the language in its SDER tariff?**

10 A. In part. The Company agrees that the language in the SDER could be made clearer
11 regarding what costs can be amortized and the methodology through which those
12 amortization amounts will be recovered. As such, the Company agrees to revise the
13 proposed SDER tariff language on page 82 of PPL Electric Exhibit GEO-1 to state:

14 In order to calculate the C factor for each application year,
15 the Company will include in the SDER all qualifying storm
16 damage expenses caused by reportable storms and non-
17 reportable storms incurred during the 12-month period
18 ending two months prior to the application year, except that
19 all qualifying expenses caused **by extraordinary storms**
20 **and** by major storm events, defined as an interruption of
21 electric service resulting from conditions beyond the control
22 of the Company which affects at least 10% of the Company's
23 customers during the course of the event for a duration of 5
24 minutes each or greater (see 52 Pa. Code §57.192), will be
25 recovered over three years and reflected in SDER rates
26 commencing in the application year after the storm occurred.

27
28 (new text in bold). This change would be reflected in the Company's compliance retail
29 tariff filed pursuant to the Commission's Final Order in this proceeding.

1
2 **Q. Does this address Mr. Walker's recommendation to clarify the tariff language in full?**

3 A. No. Mr. Walker's recommendation to clarify the language in the Company's tariff by
4 stating that the 3-year recovery period for major storms only applies to storms recovered
5 via the SDER and not residual balances when the SDER resets to zero at a base rate
6 proceeding is not needed. The 3-year recovery period for these storms only applies to
7 storms recovered via the SDER. Mr. Walker is referring to the recovery of amortized storm
8 expenses from 2011 through distribution base rates (not through the SDER) for which the
9 Company specifically received Commission approval in its 2015 Rate Case, as I noted
10 previously. The Company is not requesting to recover amortized storm costs from major
11 storm events or extraordinary storms in base rates in this instant distribution base rate case.

12
13 **Q. Do you agree with Mr. Walker that the unamortized expense balance from the**
14 **February 2024 storm should be amortized using historical filing frequency of 61**
15 **months?**

16 A. No. The expenses from the February 2024 storm, which qualified as extraordinary, are
17 currently being amortized over three years as required by the Company's Tariff and the
18 Commission's April 2014 Order. To be clear, these storm damage expenses are being
19 recovered through the SDER and are not included in the Company's revenue requirement.
20 Further, the Company opposes the proposal to amortize costs using its historical filing
21 frequency, as explained in Ms. Bethany Johnson's rebuttal testimony (PPL Electric St, No.
22 5-R).

1
2 **Q. Do you agree with Mr. Walker that the Company’s allowed storm damage expense**
3 **should be \$32,506,000 (i.e., sum of \$22,006,000 reportable storm expense allowance**
4 **and \$10,500,000 non-reportable storm expenses) to be recovered through base rates,**
5 **which equals a \$9,994,000 reduction in the FPFTY storm damage expense claim (I&E**
6 **St. No. 1, p. 15)?**

7 A. No. To be clear, the Company is proposing to recover \$42,500,000 in storm expenses
8 through distribution base rates, which consists of two components: (1) \$32,000,000 for
9 Commission reportable storms; and (2) \$10,500,000 for non-reportable storms. Any
10 amounts above or below those thresholds would be recovered from or refunded to
11 customers through the SDER, subject to the established SDER cap.

12
13 **Q. Please describe Mr. Walker’s calculation of storm expense to be included in base**
14 **distribution rates.**

15 A. Mr. Walker includes \$10,500,000 in non-reportable storm damage expenses and
16 \$22,006,000 in what he describes as “SDER reportable storm expense cap” for a total of
17 \$32,506,000 in storm expenses to be included in base distribution rates. The \$22,006,000
18 includes \$2,230,000 in annual amortized costs related to the \$11,336,000 in storm expenses
19 that exceeded the SDER cap in 2024, \$1,622,000 in amortized expenses resulting from the
20 February 2024 extraordinary storm event, and \$18,154,000 for what Mr. Walker describes
21 as “storm damage expense...to be included in the SDER prior to adding the amortized
22 expenses.” (I&E St. No. 1, p. 14.)

1
2 **Q. Are there any errors in Mr. Walker’s calculation?**

3 A. Yes. For one, Mr. Walker describes the value he calculates as the cap on “reportable storm
4 expenses included in the SDER.” (I&E St. No. 1, p. 15.) The \$42,500,000 that Mr. Walker
5 claims to be adjusting with this calculation is the amount of storm damage expenses that
6 the Company proposes to include in distribution base rates, inclusive of both Commission
7 reportable and non-reportable storms—not the cap on the SDER recovery. As previously
8 stated, the calculation of the cap on SDER is based on 3% of the Company’s forecasted
9 distribution revenues, excluding STAS. This was established and approved by the
10 Commission in its April 2014 Order.

11 Additionally, Mr. Walker is inappropriately including \$1,622,000 associated with
12 the amortization of the February 2024 extraordinary storm in his calculation of storm
13 expenses in base rates. Likewise, he fails to include or address the expenses for the
14 November 2024 extraordinary storm.

15 Finally, Mr. Walker describes the \$18,154,000 he calculates as the “storm damage
16 expense . . . to be included in the SDER prior to adding the amortized expense” (I&E St.
17 No. 1, p. 14) and then includes this amount in his calculation of storm damage expenses to
18 be recovered through base rates. This contradicts Mr. Walker’s earlier statement that this
19 value is included in the SDER.
20

21 **Q. Do you agree with Mr. Walker’s inclusion of the \$2,230,000 in his calculation?**

1 A. No, as explained in the Ms. Johnson's rebuttal testimony (PPL Electric St. No. 5-R), the
2 Company does not agree with amortizing these costs using the historic filing frequency.

3
4 **Q. Do you agree with Mr. Walker's inclusion of the \$18,154,000 in his calculation?**

5 A. Assuming Mr. Walker intended this value of \$18,154,000 to be an amount of storm damage
6 expenses included in base distribution rates, I disagree. First, Mr. Walker cites storm
7 damage expenses provided in the response to I&E-RE-V-1, which requested actual storm
8 damage expenses from "routine, non-reportable storms." Given that, this historic average
9 would be relevant to non-reportable storms only. However, Mr. Walker also includes the
10 Company's proposed \$10,500,000 in non-reportable storm expenses in his calculation. It
11 is unclear whether Mr. Walker intends for the Company to include \$28,654,000
12 (\$18,154,000 plus \$10,500,000) in base rates for non-reportable storms. Mr. Walker also
13 fails to include any amount in base distribution rates for recovery of expenses resulting
14 from Commission reportable storms. This would leave the expenses of all Commission
15 reportable storms for recovery through SDER, which is subject to the 3% cap previously
16 explained and would almost certainly fail to provide reasonable cost recovery of these
17 expenses. Additionally, the Company disagrees with the approach of utilizing a three-year
18 historic average to calculate storm damage expenses. As explained in Mr. Lookup's direct
19 testimony (PPL Electric St. No. 16), storms are becoming more frequent and more severe.
20 In the Company's experience, this is resulting in an increase in storm damage expenses on
21 average. As such, it is inappropriate to utilize historic values to forecast storm expenses
22 the Company expects to incur in the FPFTY.

Q. Please describe the Company's actual storm damage expenses that were eligible for SDER recovery over the last five years.

A. The Company's actual storm expenses eligible for SDER recovery for the reconciliation period (which runs from November 1st through October 31st each year) as reported in its SDER reconciliation and rate filings have fluctuated from between approximately \$12.6 million during the November 2021 through October 2022 period to \$59.7 million in the November 2023 to October 2024 period. Most recently, the Company incurred \$44,079,603 in actual SDER-eligible storm expenses for the period of November 2024 through October 2025. This is a 219% increase from the period of November 2019 to October 2020.

Q. Please provide the status of the Company's SDER expenses for the current SDER period (experience from November 1, 2025, through October 30, 2026, to be recovered in the January 1, 2027, through December 31, 2027 SDER rate period).

A. Under the current SDER Tariff, from November 1, 2025, through December 31, 2025, the Company experienced approximately \$13 million in actualized SDER expenses and accrued another approximately \$18.7 million in SDER expenses. This results in a total of nearly \$32 million in just the first two months of this SDER recovery period, with another ten months to go. Moreover, there is approximately \$11 million in amortizations related to extraordinary storm events in February 2024 and November 2024, which also contributes towards the calculation of SDER expenses for the period. Based on the SDER

1 cap for the period of November 1, 2025, through October 31, 2026, of \$58,598,960, and
2 taking into account interest and e-factor (over/under reconciliation amounts) values, the
3 Company is already at 79% of the SDER cap for SDER recovery in the January 1, 2027,
4 through December 31, 2027 period, using the current method.

5
6 **Q. Does Mr. Walker make any additional recommendations?**

7 A. Yes, he recommends that the Commission direct PPL Electric to remove the language
8 added to the SDER that the Company “will consider storm damage expenses exceeding
9 5% of annual distribution net income as extraordinary for SDER recovery purposes.” (I&E
10 St. No. 1, pp. 17-18.) He argues that “this additional limit could result in large single-year
11 rider recovery of storm damage expenses that would currently be designated major storms
12 subject to the three-year rider recovery period.” (I&E St. No. 1, p. 18.)

13
14 **Q. Do you agree with this recommendation?**

15 A. No. The language referenced by Mr. Walker is the definition for extraordinary storms that
16 was approved by the Commission in its April 2014 Order. The Company is already
17 amortizing the expenses from these events over three years, which was also approved by
18 that Order. PPL Electric is proposing the inclusion of that definition in the Tariff to provide
19 greater clarity and transparency regarding the costs eligible for recovery through the SDER.

20
21 **Q. Does OSBA Witness Ewen raise any concerns about the SDER?**

1 A. Yes, he raises concern about the Company's method for applying SDER to Rate LP-4. In
2 particular, he argues that application of SDER on a per customer basis is flawed because
3 the Rate LP-4 class has both a customer and demand charge, unlike Rate LP-5. (OSBA St.
4 No. 1, p. 13.)
5

6 **Q. Are these concerns founded?**

7 A. No. Application of this charge as a customer charge instead of a demand charge does not
8 change the total amount of the charge being recovered; it only changes the manner by
9 which the charge is levied.
10

11 **Q. What does Mr. Ewen recommend?**

12 A. He recommends that the SDER be applied to Rate LP-4 as a per-kW demand charge.
13 (OSBA St. No. 1, p. 13.)
14

15 **Q. Do you agree with this recommendation?**

16 A. No. As explained in the response to discovery request OSBA II-1, attached as PPL Electric
17 Exhibit KEA-2R, application of the SDER on a per-bill basis is consistent with the
18 Company's 2015 Rate Case Settlement, to which OSBA was a party, as filed on September
19 3, 2015, at Docket No. R-2015-2469275. In that case, the Company proposed making the
20 charge a per-bill charge for the Large C&I rate classes to be consistent within the Large
21 C&I customer class, as the LP-5 rate schedule includes only a customer charge. That same

1 reasoning holds true today, and I do not see any compelling reasons to deviate from how
2 this charge has historically been designed for Rate LP-4.

3
4 **Q. Does CAUSE-PA Witness Cicero raise any concerns about the SDER?**

5 A. Yes, he says that the FPFTY, SDER, and DSIC “shift risk from PPL to customers and
6 require substantial scrutiny by the Commission in its exercise of discretion in setting rates.”
7 (CAUSE-PA St. No. 1, pp. 11-12.) He asks that the Commission be mindful about how
8 PPL Electric is the only utility in Pennsylvania that has an SDER, which has “imposed
9 significant costs on consumers.” (CAUSE-PA St. No. 1, p. 12.)

10
11 **Q. Do you agree with these concerns about the SDER raised by Mr. Cicero?**

12 A. No. The SDER allows the Company to recover eligible storm damage expenses when
13 those expenses exceed the amount of storm damage expense in distribution base rates.
14 However, Mr. Cicero appears to overlook that the SDER also results in a credit for
15 customers when the Company incurs less in storm damage expense than the amount
16 included in base distribution rates. The SDER rate was most recently negative (a credit to
17 customers) for the period of January 1, 2023, through December 31, 2023. As such, the
18 SDER allows the Company to recover the actual amount of its eligible storm damage
19 expense over time, enabling the Company to respond adequately to weather events while
20 facilitating more gradual rate changes in the future.

21 Furthermore, there are already several customer protections in place with the
22 SDER, including the amortization of expenses from major events, the amortization of

1 expenses from extraordinary events, and the rate cap of 3% of the total intrastate operating
2 revenues billed to customers, excluding STAS.

3 Lastly, the SDER does not cause customers to incur additional costs for major or
4 extraordinary storm events, as alleged by Mr. Cicero. Without the SDER, PPL Electric
5 would petition for deferred accounting of the costs associated with such events, so that the
6 Company could make a claim for recovery in the next base rate case.

7 **III. CASH WORKING CAPITAL**

8 **Q. Did the Company identify any errors in I&E Witness Keller and OCA Witness**
9 **Koenig's recalculation of the Company's Cash Working Capital ("CWC") claim?**

10 A. Yes. I&E Witness Keller makes adjustments to O&M expenses but fails to incorporate the
11 impact of those changes on accrued taxes and interest within his CWC calculation. OCA
12 Witness Koenig has failed to update the rate base value based on the adjustments made as
13 part of the CWC calculation. OCA takes the position that the rate case expense and the
14 Competitive Enhancement Rider ("CER") expense adjustment should be considered non-
15 cash items, with which the Company does not agree. Regardless, OCA Witness Koenig
16 does not incorporate OCA's proposed adjustment to the rate case expense amount in the
17 CWC calculation. Additionally, she removes the expense associated with the OCA's
18 proposal to eliminate the CER expense from the total O&M value but fails to eliminate the
19 CER expense value from the total value of non-cash items. Ms. Koenig also fails to adjust
20 the accrued tax value in response to OCA's proposed O&M changes.

1 **Q. How does I&E Witness Keller summarize the Company’s CWC claim?**

2 A. Mr. Keller notes that the CWC claim, which was calculated based on the Company’s
3 lead/lag study, is \$16,775,000. (I&E St. No. 2, p. 32-33.) He further acknowledges an
4 error that PPL Electric identified in response to I&E-RE-I-2-D, which would “increase
5 O&M expenses resulting in an increase in the average lag of operating expenses and a
6 reduction in average lag days between payment of operating expense and receipt of revenue
7 from 5.2 days to 5.1 days.” (I&E St. No. 2, p. 33.)
8

9 **Q. Does Mr. Keller agree with the Company’s claim?**

10 A. He does not agree with the claimed amount; however, he does agree with the Company’s
11 use of the lead/lag method. (I&E St. No. 2, p. 34).
12

13 **Q. What does Mr. Keller recommend?**

14 A. He recommends an allowance of \$11,297,000, which is a reduction of \$5,578,000 to the
15 Company’s claim. (I&E St. No. 2, p. 34.) He recommends two adjustments: (1) a change
16 to the expense lag days corresponding to Affiliate Support from 35 days to 45 days; and
17 (2) inclusion of adjustments to O&M expenses as discussed in his direct testimony and
18 I&E Witness Walker’s direct testimony. (I&E St. No. 2, p. 34.) Mr. Keller notes, however,
19 that his recommendations are not final, as the CWC allowance will need to be adjusted
20 based on all adjustments to PPL Electric’s claims for revenues, expenses, taxes, and rate
21 base, as determined by the Commission. (I&E St. No. 2, p. 34.).
22

1 **Q. What is the basis for these recommendations?**

2 A. Regarding his recommendation to change the lag days for the affiliate support from 35 to
3 45 days, Mr. Keller explains that the basis for the recommendation is “to change the
4 expense lag days corresponding to Affiliate Support costs from 35 day to 45 days” in order
5 to align “payment timing with the terms of the service agreement and removes unnecessary
6 early payment, to maximize the holding period of cash to the Company’s and ratepayers’
7 benefit.” (I&E St. No. 2, p. 35.) He further describes the Company’s service agreements
8 with affiliates and argues that “[r]atepayers should not bear costs associated with CWC
9 increases that result from unnecessary and disadvantageous early payments, which in this
10 instance are being paid to a PPL-affiliated company.” (I&E St. No. 2, p. 35.) Based on
11 his recalculation of the average lag with this adjustment, Mr. Keller asserts that the
12 Company experiences no lag in receipt of revenue relative to payment of O&M expenses,
13 so “there should be no CWC requirement associated with this factor.” (I&E St. No. 2, pp.
14 35-36.) Mr. Keller also avers that he included cash-based O&M recommendations when
15 computing the overall recommended CWC allowance and then summarizes those expense
16 adjustments proposed by him and I&E witness Walker. (I&E St. No. 2, pp. 36-37.)

17
18 **Q. Do you agree with the recommendation to change the expense lag days corresponding**
19 **to Affiliate Support costs from 35 days to 45 days?**

20 A. No. The lead/lag study is based on the difference between when services are received and
21 when payments are actually made. Here, PPL Electric pays for these services from PPL
22 Services Corporation and non-affiliated vendors on the 20th of each month. In other words,

1 the Company does not treat its payment for its Affiliate Support services any differently
2 than it does payments to external vendors. By aligning the payments to affiliated and non-
3 affiliated companies alike, PPL Electric simplifies its payment processes and gains
4 efficiencies in its operations. Moreover, a payment due within 30 days of service is
5 commercially reasonable and typical of terms required by PPL Electric's vendors. I do not
6 believe it would be reasonable for PPL Electric to pay its affiliate vendors more slowly
7 than it pays its non-affiliated vendors and lose out on the simplicity and efficiency of its
8 current payment process. In addition, the terms of the service agreement state that payment
9 is due *within* 30 days and does not mandate payment on the 30th day.

10
11 **Q. Do you agree with cash-based O&M recommendations proposed by Mr. Keller?**

12 A. In part. As addressed in PPL Electric Witness Urban's rebuttal testimony (PPL Electric
13 St. No. 2-R), the Company accepted the proposal to adjust its claim for sponsorships.
14 Additionally, the Company accepted the proposed adjustment to payroll taxes (PPL
15 Electric St. No. 12-R). However, the Company does not accept the proposed adjustments
16 to advertising expense, payment transactions, bank charges, and memberships (PPL
17 Electric St. No. 2-R). The Company also does not accept the proposed adjustments to rate
18 case expense (see PPL Electric St. No. 5-R), vegetation management expense (see PPL
19 Electric St. No. 18-R), economic development expense (see PPL Electric St. No. 21-R),
20 and incentive compensation expense (see PPL Electric St. No. 23-R). Finally, as
21 previously explained in my rebuttal testimony, the Company does not accept the proposed
22 adjustment to storm damage expenses.

Q. What do OCA Witness Morgan and OCA Witness Koenig recommend regarding the CWC?

A. OCA Witness Koenig recommends that PPL Electric's proposed cash working capital be reduced by approximately \$7.17 million for the FPFTY. (OCA St. 2, p. 4.) She notes that she incorporates OCA Witness Morgan's adjustments to O&M expenses and OCA Witness Garrett's recommended long-term debt ratio and embedded cost of debt. (OCA St. 2, p. 2.) OCA Witness Morgan also incorporates OCA Witness Koenig's adjustment to CWC, which results in an approximately \$7.2 million decrease in the CWC allowance. (OCA St. 1, pp. 7-8.)

Q. Do you agree with the adjustments proposed by OCA Witness Morgan?

A. I agree in part. As explained in PPL Electric Witness Urban's rebuttal testimony (PPL Electric St. No. 2-R), the Company accepted in part the proposal to adjust membership dues to correct for the overstatement in the FPFTY. The Company also accepted I&E's proposed allowance for payroll taxes (see PPL Electric St. No. 12-R). Additionally, as I explained later in this testimony, PPL Electric accepts the proposal to withdraw the proposal to recover Eligible Customer List ("ECL") costs through distribution base rates. However, the Company does not accept the adjustments to payroll expenses, Goodwill & Institutional Advertising, R&D expenses, and sponsorships, as outlined in PPL Electric St. No. 2-R. The Company also does not agree with the adjustments to incentive compensation (see PPL Electric St. No. 23-R), payment transaction fees and Universal Service Rider

1 (“USR”) salaries (see PPL Electric St. No. 18-R), the Infrastructure Investment and Jobs
2 Act (“IIJA”) regulatory asset (see PPL Electric St. No. 22-R), rate case expense (see PPL
3 Electric St. No. 5-R), Public Utility Realty Tax Act (“PURTA”) tax (see PPL Electric St.
4 No. 12-R), affiliate support – engineering & construction expense (see PPL Electric St. No.
5 20-R), depreciation rates (see PPL Electric St. No. 11-R), and economic development (see
6 PPL Electric St. No. 21-R).

7
8 **Q. What changes does OCA Witness Koenig make to the Company’s CWC calculation?**

9 A. OCA Witness Koenig identifies three additional non-cash items that she believes should
10 be excluded from the Company’s CWC calculation. These items are the normalization of
11 rate case expenses, the normalization of CER costs, and the amortization of several
12 expenses. (OCA St. 2, p. 7.) She also removes the amortization of IIJA costs as OCA is
13 recommending that recovery be disallowed (OCA St. 2, p. 8). OCA Witness Koenig
14 removes the PURTA expense from the accrued tax calculation, slightly changes the
15 midpoint of interest payment days from 90 to 91.25, incorporates the long-term cost of debt
16 and long-term debt ratio proposed by OCA Witness Morgan (OCA St. 2, p. 9), and modifies
17 the Company’s lead/lag study, resulting in an average lag for receipt of revenue of 47.78
18 days, an average lag for payment of operation expenses of 43.14 days, and an average lag
19 between payment of operating expenses and receipt of revenue of 4.64 days. (OCA St. 2,
20 pp. 14-16.).

21

1 **Q. Should the proposal to exclude these three additional non-cash items be approved?**

2 A. No. As a preliminary matter, the \$72,865 in amortization that Ms. Koenig removes on OCA
3 Exhibit GNK-2 line 9 for software amortization is included in the \$289,596 depreciation
4 expense the Company removed from its CWC calculation (provided in line 2 of Exhibit
5 GNK-2), so removing that again is double counting. As such, that adjustment should not
6 be made.

7 Additionally, as described later in my rebuttal testimony, the Company agrees to
8 withdraw the proposal to normalize its CER costs. Given that, the amount for the CER
9 costs provided in Schedule D-8 will no longer be included in the calculation of Total Pro-
10 Forma Operation and Maintenance Expense and thus does not need to be removed.

11 Finally, I do not agree with removing the normalization of rate case expense. Ms.
12 Koenig is inappropriately treating this normalization expense as an amortization. Further,
13 the Company has consistently included the normalization of rate case expense in its Total
14 Pro-Forma Operation and Maintenance Expense value in its CWC calculation and has
15 received approval to do so from the Commission.

16
17 **Q. Do you agree with the removal of the IIJA costs and PURTA tax expense?**

18 A. No. The Company opposes the elimination of the IIJA cost adjustment, as explained in the
19 rebuttal testimony of PPL Electric Witness Leskowsky (PPL Electric St. No. 22-R) as well
20 as the elimination of the PURTA tax adjustment as explained by PPL Electric Witness
21 Elmore (PPL Electric Statement No. 12-R).

22

1 **Q. Is it appropriate to change the midpoint of interest payments from 90 to 91.25 days?**

2 A. No. I have been advised by PPL Electric Witness Burgos that the Company's use of 90
3 days is consistent with the 30/360 day count convention, which is the standard in U.S. Bond
4 Markets. This value has also been consistently proposed by the Company and accepted by
5 the Commission in the Company's prior base rate cases.

6
7 **Q. Do you agree with incorporating the long-term cost of debt and long-term debt ratio
8 proposed by OCA Witness Morgan?**

9 A. No. The Company opposes OCA Witness Morgan's long-term debt proposals as explained
10 in the rebuttal testimony of PPL Electric Witness Burgos (PPL Electric St. No. 9-R) and
11 PPL Electric Witness Nelson (PPL Electric St. No. 10-R).

12
13 **Q. Please describe the proposed changes to the Company's lead/lag study.**

14 A. OCA Witness Koenig proposes several changes to the Company's lead/lag study. First,
15 she proposes using actual invoice and payment dates to calculate the lag for employee
16 expenses, as opposed to the Company's methodology of using the pay-period basis. (OCA
17 St. 2, pp. 11-12.) For Materials and Supplies, Printing and Office Supplies, Services,
18 Postage, Telephone and Leased Wires, Rents, Advertising, and Miscellaneous expenses,
19 OCA Witness Koenig recalculated the weighted average lag days using all the invoices
20 provided by the Company in discovery, rather than the Company's selected sample. (OCA
21 St. 2, pp. 12-13.) She also excluded NJUNs, Inc. Invoice No. 15170, as well as Invoice
22 No. 72302, and expanded the results of her analysis to two decimal places. (OCA St. 2, p.

1 13.) She also states that she expanded the revenue lag calculation to two decimal points to
2 be consistent with other calculations within the study. (OCA St. 2, p. 14.) Finally, OCA
3 Witness Koenig avers that she was unable to identify where the Company provided its
4 updated CWC calculation that resulted in the revised average lag days of 5.1 days. (OCA
5 St. 2, p. 17.)
6

7 **Q. Do you agree that the lag for Materials and Supplies, Printing and Office Supplies,**
8 **Services, Postage, Telephone and Leased Wires, Rents, Advertising, and**
9 **Miscellaneous expenses should be recalculated using the weighted average lag days**
10 **using all the invoices provided by the Company in discovery instead of a sample of**
11 **invoices?**

12 **A.** No. In this case and prior rate cases, the Company has elected to use a sample of invoices
13 from each budget item to calculate the lag so analysts can pull and review the actual invoice
14 copies, evaluate the service date, calculate the midpoint of service, if applicable, and
15 validate the information included in the report for those selected in the sample. This is a
16 manual process. OCA Witness Koenig is recommending that the Company use all of the
17 invoices charged to each budget item during the Historic Test Year (“HTY”) to calculate
18 the lag. This includes over 35,000 invoices. If one were to assume it takes an analyst five
19 minutes to pull, review, and validate a single invoice, which is a conservative time estimate,
20 this would require 2,916 hours, or approximately 365 working days, to pull, review, and
21 validate all 35,000 invoices. Ms. Koenig’s analysis, however, is just a calculation of data
22 in the spreadsheet and does not include the review of the actual invoice copy.

1
2 **Q. Do you believe the benefit of pulling, reviewing, and validating all 35,000 invoices**
3 **outweighs the cost of dedicating at least 2,916 working hours to that task?**

4 A. No. OCA Witness Koenig's recalculation of lag days using all invoices results in a
5 weighted-average lag in payment for Other Operating Expenses of 68.63 days as compared
6 to the Company's calculation of 67.07 days, a difference of just 1.56 days. Further, OCA
7 Witness Koenig notes in her analysis she excluded invoice number 72302 from the list of
8 invoices in the list of all Materials and Supplies invoices because the Company had flagged
9 that invoice as being a duplicate (and properly excluded it from the sample). (OCA St. 2,
10 p. 13.) This example is further evidence that including all roughly 35,000 invoices would
11 require the Company to dedicate an analyst to pulling, reviewing, and validating all of the
12 invoices, a task which the Company estimates would take a minimum of 2,916 hours.

13
14 **Q. Do you agree with OCA Witness Koenig that the lag for employee expenses should be**
15 **based on the actual invoice and payment dates?**

16 A. No. As previously stated, the Company does not believe it is a worthwhile initiative to
17 dedicate the time to pulling, reviewing, and validating all of the invoices charged to a
18 budget item during the HTY when using a sample of invoices results in a comparable value
19 for the average lag in payment for Other Operating Expenses. OCA Witness Koenig states
20 that her calculation using all invoices charged to the budget item for employee expenses,
21 which results in a lag of 27.31 days compared to the Company's proposed lag of 12 days,
22 reflects the actual payment lag. (OCA St. 2, p. 12.) However, without pulling and

1 reviewing the invoices and documentation associated all 16,543 invoices charged to that
2 budget item (a task that the Company estimates would take a minimum of 1,379 hours),
3 this cannot be confirmed. Rather, it is more accurate to calculate this lag based on the
4 established process of reimbursing employee expenses by using the midpoint of the 14-day
5 payroll period in which the employee is reimbursed, plus the lag between the end of the
6 payroll cycle and pay day. This is consistent with how the Company has proposed and
7 received Commission approval to calculate the lag for employee expenses in prior rate
8 cases.

9
10 **Q. Do you support excluding the NJUNs, Inc. Invoice No. 15170 as well as Invoice No.**
11 **72302?**

12 A. In part. I agree that the NJUN, Inc. Invoice No. 15170 should be excluded from the
13 analysis. Removal of this invoice from the study would not change the resulting 67.06 days
14 lag calculation. However, based on my previous argument, I do not think Invoice No.
15 72302 should have been included in the analysis to begin with, as it was not included in
16 the Company's sample and thus would not need to be excluded.

17
18 **Q. Do you agree that the analysis should be expanded to two decimal points?**

19 A. No. The Company has consistently proposed and received Commission approval in prior
20 distribution rate cases to calculate lag days with one decimal point. OCA Witness Koenig
21 argues that, by including just one decimal point, the Company is "inconsistent with its
22 calculation of each operating expense component." (OCA St. 2, p. 14.) However,

operating expenses and days are entirely different types of values. It is not necessary to round them to the same number of decimal places, and it is the position of the Company, and this Commission in multiple prior rate case filings, that it is appropriate to round the calculation of lag days to a single decimal point.

Q. Can you provide the reference to the updated CWC calculation which provides a revised average lag of 5.1 days?

A. Yes. The updated CWC calculation was provided in discovery request OCA I-1 Attachment 231 SUPPLEMENTAL. (See PPL Electric Exhibit DAU-2R.)

Q. Related to cash working capital, CAUSE-PA Witness Cicero proposes to revise the Company's Tariff such that bills be considered rendered within 3 days from the day that they are placed in the mail. (See CAUSE-PA St. No. 1, pp. 131-32.) Do you agree with this proposal?

A. No. Section 56.21 of the Commission's regulations states that "[t]he due date for payment of a bill may not be less than 20 days from the date of transmittal; that is, the date of mailing, electronic transmission, or physical delivery of the bill by the public utility to the customer." 52 Pa. Code § 56.21. Therefore, the Company is allowed to consider either the date the bill is mailed (date of mailing) or the date the bill is received by the customer (physical delivery of the bill).

Further, while Mr. Cicero makes a recommendation for consideration of additional days, he proposes no adjustment to increase the Company's cash working capital claim.

1 The cash working capital claim would, in theory, include the additional three (3) revenue
2 lag days that Mr. Cicero proposes, increasing the overall lag days between the payment of
3 operating expenses and receipt of revenue, as shown on Exhibit Historic 1, Schedule C-4,
4 page 2, line 10. This results in an increase to working capital requirement that is included
5 in the Company's revenue requirement and recovered from customers.

6 Additionally, this would require the Company to make billing code changes, yet
7 Mr. Cicero makes no estimate or adjustment to the Company's revenue requirement claim
8 for higher IT costs. Also, Mr. Cicero has not provided any evidence in this case to support
9 his concern. As such, it is the Company's position that the Commission should deny Mr.
10 Cicero's recommendation and not increase costs to customers without evidence of an
11 offsetting resulting benefit.

12
13 **IV. ELIGIBLE CUSTOMER LIST EXPENSES**

14 **Q. Does OCA Witness Morgan recommend any adjustment to the ECL Expenses?**

15 A. Yes, OCA Witness Morgan recommends an adjustment to remove the \$100,000 annual
16 amortization for the ECL costs because the next ECL update is not due until 2029, which
17 is beyond the FPFTY (see OCA Exhibit LKM-11). (OCA St. 1, pp. 17-18).

18
19 **Q. Do you agree with this recommendation?**

20 A. Yes. In this proceeding, PPL Electric originally proposed to recover the costs of
21 administering the ECL in base rates due to the elimination of the CER, as explained in my
22 direct testimony (PPL Electric St. No. 13). However, since the next ECL update is not due

1 until 2029, the Company agrees that the *pro forma* adjustments to reflect the recovery of
2 these costs in base rates is not necessary at this time. Therefore, the Company has adjusted
3 its revenue requirement to remove this adjustment (see PPL Electric St. No. 6-R).

4
5 **V. CONCLUSION**

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

7 A. Yes, it does.

PPL ELECTRIC UTILITIES CORPORATION
Storm Damage Expense Rider ("SDER")
Application Period: January 1, 2026 through December 31, 2026

Line No.		(A)	(B)	(C)	(D)	(E)
		Residential	Small C&I	Large C&I - Primary	Large C&I - Transmission	Total
1	Total Expenses (Schedule B, Line 9)	\$ 26,091,582	\$ 9,123,685	\$ 1,792,750	\$ 185,970	\$ 37,193,987
2	Projected Total 2026 kWh Sales	14,595,486,701	10,273,347,882			24,868,834,583
3	Projected Total 2026 Customer Count			15,139	1,898	17,037
4	1/(1-T) = (T=5.9% Gross Receipts Tax)	1.062699	1.062699	1.062699	1.062699	
5	SDER = STORM DAMAGE EXPENSE RIDER					
	Rate (\$/kWh) w/o GRT	\$ 0.00179	\$ 0.00089			
	Rate (\$/kWh) w/ GRT	\$ 0.00190	\$ 0.00094			
	Rate (\$/Customer) w/o GRT			\$ 118.42	\$ 97.98	
	Rate (\$/Customer) w/ GRT			\$ 125.84	\$ 104.13	

Schedule A

PPL ELECTRIC UTILITIES CORPORATION
Storm Damage Expense Rider ("SDER")
Application Period: January 1, 2026 through December 31, 2026

Line No.		(A)	(B)	(C)	(D)	(E)
1	Cost Allocation	Residential 70.15%	Small C&I 24.53%	Large C&I - Primary 4.82%	Large C&I - Transmission 0.50%	Total 100.00%
2	C Factor - Storm Damage Expenses (Line 1 x Column E)	\$ 30,921,842	\$ 10,812,727	\$ 2,124,637	\$ 220,398	\$ 44,079,603
3	C Factor Interest (Line 1 x Column E)	\$ 1,679,259	\$ 587,202	\$ 115,382	\$ 11,968	\$ 2,393,811
4	C Factor - Deferred 2026 Storm Expenses (Line 1 x Column E)	\$ 7,736,066	\$ 2,705,142	\$ 531,544	\$ 55,139	\$ 11,027,892
5	Total C Factor Expenses	<u>\$ 40,337,167</u>	<u>\$ 14,105,071</u>	<u>\$ 2,771,563</u>	<u>\$ 287,505</u>	<u>\$ 57,501,306</u>
6	R Factor - Rate Base Storm Damage Expenses (Line 1 x Column E)	\$ 14,046,836	\$ 4,911,887	\$ 965,157	\$ 100,120	\$ 20,024,000
7	E Factor - Under/(Over) Collection from Prior Period	\$ 1,283,866	\$ 460,258	\$ 158,816	\$ 8,865	\$ 1,911,805
8	Total SDER = (C - R) + E	\$ 27,574,197	\$ 9,653,442	\$ 1,965,222	\$ 196,250	\$ 39,389,111
9	Total SDER with Cap (Line 1 x Column E)	\$ 26,091,582	\$ 9,123,685	\$ 1,792,750	\$ 185,970	\$ 37,193,987
10	Excess Expenses Over 3% Cap (Line 8 - Line 9)	\$ 1,482,615	\$ 529,757	\$ 172,472	\$ 10,280	\$ 2,195,124

Line 1 per the Company's most recent settled distribution base rate case at Docket No. R-2015-2469275.

Line 2 from Schedule C (Line 4, Column M) multiplied by the Cost Allocation.

Line 3 from Schedule D (Line 13, Column D).

Line 4 February 2024 Winter Storm and November 2024 Winter Storm expenses for 12 months of the 36 month amortization multiplied by the Cost Allocation.

Line 6 from Schedule C (Line 3, Column M) multiplied by the Cost Allocation.

Line 7 from SDER Reconciliation

Line 9 per Docket No. R-2012-2290597, if storm damage expense available for recovery exceeds 3% of total annual intrastate revenue, the excess expenses will be deferred and available for recovery in the Company's next base rate case under Section 1308.

PPL ELECTRIC UTILITIES CORPORATION
(OVER)/UNDER COLLECTIONS ON STORM DAMAGE EXPENSE RIDER (SDER) BY MONTH
RESIDENTIAL, SMALL COMMERCIAL AND INDUSTRIAL AND LARGE COMMERCIAL AND INDUSTRIAL
Report For The Period November 1, 2024 To October 31, 2025

Line No.		(A) November-24	(B) December-24	(C) January-25	(D) February-25	(E) March-25	(F) April-25	(G) May-25	(H) June-25	(I) July-25	(J) August-25	(K) September-25	(L) October-25	(M) Total November-24 to October-25
1	Amount recovered through distribution rates as allowed per Distribution Rate Case (Annually) (1)	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	\$ 20,024,000	
2	Percentage for Current Month (2)	8.12%	9.26%	9.62%	8.78%	8.57%	7.53%	7.51%	8.08%	8.90%	8.59%	7.54%	7.50%	
3	Storm revenue recovered through distribution rates for the current month (Line 1 x line 2)	\$ (1,624,956)	\$ (1,854,401)	\$ (1,925,310)	\$ (1,758,784)	\$ (1,715,913)	\$ (1,507,448)	\$ (1,504,794)	\$ (1,617,824)	\$ (1,782,566)	\$ (1,720,630)	\$ (1,509,527)	\$ (1,501,845)	\$ (20,024,000)
4	Actual Storm Expense for Current Month	\$ 7,597,805	\$ 5,918,166	\$ 15,590,053	\$ (9,012,238)	\$ 3,225,096	\$ 4,065,801	\$ 5,657,207	\$ 4,577,072	\$ 3,331,419	\$ 834,896	\$ 1,188,712	\$ 1,105,614	\$ 44,079,603
5	(Over)/Under Collection SDER	\$ 5,972,849	\$ 4,063,765	\$ 13,664,743	\$ (10,771,022)	\$ 1,509,183	\$ 2,558,353	\$ 4,152,413	\$ 2,959,248	\$ 1,548,853	\$ (885,734)	\$ (320,815)	\$ (396,231)	\$ 24,055,603
Percentage by Customer Class (1)														
6	70.15% Residential (Over)/Under Collection (Line 5 x customer class percentage)	\$ 4,189,953	\$ 2,850,731	\$ 9,585,817	\$ (7,555,872)	\$ 1,058,692	\$ 1,794,684	\$ 2,912,918	\$ 2,075,912	\$ 1,086,521	\$ (621,343)	\$ (225,052)	\$ (277,956)	\$ 16,875,006
7	24.53% Small C&I (Over)/Under Collection (Line 5 x customer class percentage)	\$ 1,465,140	\$ 996,841	\$ 3,351,961	\$ (2,642,132)	\$ 370,203	\$ 627,564	\$ 1,018,587	\$ 725,903	\$ 379,934	\$ (217,271)	\$ (78,696)	\$ (97,195)	\$ 5,900,839
8	4.82% Large C&I - Primary (Over)/Under Collection (Line 5 x customer class percentage)	\$ 287,891	\$ 195,873	\$ 658,641	\$ (519,163)	\$ 72,743	\$ 123,313	\$ 200,146	\$ 142,636	\$ 74,655	\$ (42,692)	\$ (15,463)	\$ (19,098)	\$ 1,159,480
9	0.50% Large C&I - Transmission (Over)/Under Collection (Line 5 x customer class percentage)	\$ 29,864	\$ 20,319	\$ 68,324	\$ (53,855)	\$ 7,546	\$ 12,792	\$ 20,762	\$ 14,796	\$ 7,744	\$ (4,429)	\$ (1,604)	\$ (1,981)	\$ 120,278
10	Total	\$ 5,972,849	\$ 4,063,765	\$ 13,664,743	\$ (10,771,022)	\$ 1,509,183	\$ 2,558,353	\$ 4,152,413	\$ 2,959,248	\$ 1,548,853	\$ (885,734)	\$ (320,815)	\$ (396,231)	\$ 24,055,603

(1) Per the Company's most recent settled distribution base rate case at Docket No. R-2015-2469275.

(2) Percentage is based on the Company's 5-year average sales.

PPL ELECTRIC UTILITIES CORPORATION
INTEREST EXPENSE ON STORM DAMAGE EXPENSE RIDER
(OVER)/UNDER COLLECTIONS BY MONTH

Line No.	Month	(A) Interest Rate	(B) Weighting Factor	(C) (D)		(C) (D)		(C) (D)		(C) (D)		(C) (D)	
				Total	Residential	Small Commercial and Industrial	Large Commercial and Industrial - Primary	Large Commercial and Industrial - Transmission					
				(Over)/Under Collection Total (1)	Interest on (Over)/Under Collection	(Over)/Under Collection Total (1)	Interest on (Over)/Under Collection	(Over)/Under Collection Total (1)	Interest on (Over)/Under Collection	(Over)/Under Collection Total (1)	Interest on (Over)/Under Collection	(Over)/Under Collection Total (1)	Interest on (Over)/Under Collection
1	November-24	6.50%	20/12	\$ 5,972,849	\$ 647,058	\$ 4,189,953	\$ 453,912	\$ 1,465,140	\$ 158,723	\$ 287,891	\$ 31,188	\$ 29,864	\$ 3,235
2	December-24	6.75%	19/12	\$ 4,063,765	\$ 434,315	\$ 2,850,731	\$ 304,672	\$ 996,841	\$ 106,537	\$ 195,873	\$ 20,934	\$ 20,319	\$ 2,172
3	January-25	7.00%	18/12	\$ 13,664,743	\$ 1,434,798	\$ 9,585,817	\$ 1,006,511	\$ 3,351,961	\$ 351,956	\$ 658,641	\$ 69,157	\$ 68,324	\$ 7,174
4	February-25	7.00%	17/12	\$ (10,771,022)	\$ (1,068,127)	\$ (7,555,872)	\$ (749,291)	\$ (2,642,132)	\$ (262,011)	\$ (519,163)	\$ (51,484)	\$ (53,855)	\$ (5,341)
5	March-25	7.25%	16/12	\$ 1,509,183	\$ 145,887	\$ 1,058,692	\$ 102,340	\$ 370,203	\$ 35,786	\$ 72,743	\$ 7,032	\$ 7,546	\$ 729
6	April-25	7.00%	15/12	\$ 2,558,353	\$ 223,856	\$ 1,794,684	\$ 157,035	\$ 627,564	\$ 54,912	\$ 123,313	\$ 10,790	\$ 12,792	\$ 1,119
7	May-25	7.00%	14/12	\$ 4,152,413	\$ 339,114	\$ 2,912,918	\$ 237,888	\$ 1,018,587	\$ 83,185	\$ 200,146	\$ 16,345	\$ 20,762	\$ 1,696
8	June-25	7.00%	13/12	\$ 2,959,248	\$ 224,410	\$ 2,075,912	\$ 157,423	\$ 725,903	\$ 55,048	\$ 142,636	\$ 10,817	\$ 14,796	\$ 1,122
9	July-25	7.25%	12/12	\$ 1,548,853	\$ 112,291	\$ 1,086,521	\$ 78,773	\$ 379,934	\$ 27,545	\$ 74,655	\$ 5,412	\$ 7,744	\$ 561
10	August-25	7.25%	11/12	\$ (885,734)	\$ (58,863)	\$ (621,343)	\$ (41,293)	\$ (217,271)	\$ (14,439)	\$ (42,692)	\$ (2,837)	\$ (4,429)	\$ (294)
11	September-25	7.25%	10/12	\$ (320,815)	\$ (19,383)	\$ (225,052)	\$ (13,597)	\$ (78,696)	\$ (4,755)	\$ (15,463)	\$ (934)	\$ (1,604)	\$ (97)
12	October-25	7.25%	9/12	\$ (396,231)	\$ (21,545)	\$ (277,956)	\$ (15,114)	\$ (97,195)	\$ (5,285)	\$ (19,098)	\$ (1,038)	\$ (1,981)	\$ (108)
13	Total			\$ 24,055,603	\$ 2,393,811	\$ 16,875,006	\$ 1,679,259	\$ 5,900,839	\$ 587,202	\$ 1,159,480	\$ 115,382	\$ 120,278	\$ 11,968

(1) From Schedule C, Line 6, 7, 8 and 9 for the respective month.

PPL Electric Utilities Corporation

Appendix for
Storm Damage Expense Rider

2025 Storm Cost Detail

Year to Date 10/31/2025 (including 11/30/2024 and 12/31/2024)

Storm ID	Description	Grand Total			Total Capital			Total			Payroll			PPL Overheads		Other Allocated Expenses			Remaining		ST wages from CATGA (Tab D)		Other Non Recoverable Expenses			TOTAL RECOVERABLE		TOTAL NON-RECOVERABLE	
		Cost		Cost (D)	Expense		ST - straight time		OT - overtime		Total	Other OH		Total	Employee Expense (A)		Transportation (B)	Total	Expenses (C)				BI 13300	BI 34000	Total	STORM EXPENSE (D)		STORM EXPENSE	
10049302	PUC STORM JUL 12 2022	871.56		407.88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	463.68	-	-	-	-	-	-	-	-	-	
10049400	PUC STORM NOV 30 2022	4,120.04		1,937.82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,192.42	-	-	-	-	-	-	-	-	-	
10050202	PUC STORM DEC 12 2022	30,114.65		13,607.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,507.61	-	-	-	-	-	-	-	-	-	
10050203	PUC STORM DEC 23 2022	70,565.39		34,830.50	35,734.89	-	-	-	1,511.31	-	-	1,511.31	-	-	417.13	417.13	-	359.24	359.24	35,734.89	-	-	-	-	-	35,734.89	-	2,287.68	
10050204	PUC STORM FEB 21 2023	17,228.98		1,660.17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,568.81	-	-	-	-	-	-	-	-	-	
10050305	PUC STORM MAR 3 2023	10,390.54		10,333.59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56.95	-	-	-	-	-	-	-	-	-	
10050835	PUC STORM MAR 7, 2023	13,632.40		11,053.68	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,578.72	-	-	-	-	-	-	-	-	-	
10050836	PUC STORM APR 1, 2023	6,902.15		9,152.13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,249.98)	-	-	-	-	-	-	-	-	-	
10050841	PUC STORM APR 22, 2023	30,542.95		25,947.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,595.39	-	-	-	-	-	-	-	-	-	
10050842	PUC STORM JUNE 3, 2023	12,589.89		18,108.84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,518.95)	-	-	-	-	-	-	-	-	-	
10050843	PUC STORM - AUG 7, 2023	(702.78)		(4,228.19)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,525.41	-	-	-	-	-	-	-	-	-	
10050844	PUC STORM - AUG 12, 2023	(2,245.60)		(1,056.68)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,188.92)	-	-	-	-	-	-	-	-	-	
10050845	PUC STORM - AUG 16, 2023	8,570.73		4,011.11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,559.62	-	-	-	-	-	-	-	-	-	
10050846	PUC STORM SEPT 7, 2023	(5,837.56)		(2,722.86)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,094.70)	-	-	-	-	-	-	-	-	-	
10060134	PUC STORM SEPT 9, 2023	(868.95)		(460.86)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(460.86)	-	-	-	-	-	-	-	-	-	
10060135	PUC STORM SEP 23, 2023	37,533.58		36,186.53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,654.95)	-	-	-	-	-	-	-	-	-	
10060136	PUC STORM DEC 10, 2023	12,059.59		14,316.91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,257.32)	-	-	-	-	-	-	-	-	-	
10060138	PUC STORM JAN 8, 2024	(336,772.26)		(325,802.19)	-	-	-	-	571.32	571.32	-	-	236.95	236.95	51.80	-	51.80	-	(11,593.19)	-	-	-	-	-	-	-	236.95	-	
10060551	PUC STORM JAN 12, 2024	(644,166.83)		(645,776.41)	-	-	-	-	-	-	-	-	(584.91)	(584.91)	-	-	-	-	4,673.15		-	-	-	-	-	-	1,579.58	2,508.66	
10060553	PUC STORM - FEB 28, 2024	(127,320.51)		(128,728.86)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,419.35	-	-	-	-	-	-	-	-	-	
10060554	PUC STORM - MAR 10, 2024	(204,752.20)		(207,886.10)	112.24	385.97	498.21	(40.54)	(40.54)	16.00	-	16.00	-	-	-	-	30.18	30.18	6,212.96		-	-	-	-	-	-	3,133.90	3,566.91	
10060555	PUC STORM - MAR 23, 2024	(39,838.86)		(42,321.43)	-	-	-	-	-	-	-	-	(219.83)	(219.83)	-	-	-	-	2,482.59	-	-	-	-	-	-	-	-	(219.83)	
10060874	PUC STORM - APR 2, 2024	578,304.17		37,579.81	-	-	-	-	-	-	-	-	-	-	-	-	19,453.81	-	19,453.81	-	-	-	-	-	-	-	-	-	
10060875	PUC STORM - APR 14, 2024	(42,575.94)		(55,357.33)	-	-	-	-	726.92	1,520.93	-	-	419.78	419.78	102.90	-	23.03	125.93	11,951.57	-	-	-	-	-	-	-	12,781.39	1,236.82	
10060876	PUC STORM 5-23-2024	422,689.65		147,789.69	-	-	-	-	-	-	-	-	1,145.98	1,145.98	-	-	-	-	273,960.96	-	-	-	-	-	-	-	273,960.96	1,145.98	
10060877	PUC STORM - JUNE 21-22, 2024	2,347,300.34		1,031,136.39	65.37	-	65.37	-	-	-	-	-	18.03	18.03	-	-	151.40	-	1,319,508.61		-	-	-	-	-	-	1,316,163.95	3,579.46	
10060878	PUC STORM - JUNE 26, 2024	11,849,806.69		5,403,057.47	6,446,749.22	-	-	54.57	456.52	511.09	-	-	726.00	726.00	13,593.21	-	151.67	13,744.88	6,436,051.33		-	-	-	-	-	-	6,446,749.22	3,284.08	
10060964	PUC STORM - JULY 15, 2024	2,331,155.50		994,329.34	1,336,826.16	-	-	82.34	-	82.34	-	-	82.34	82.34	-	-	201.49	-	1,336,826.16		-	-	-	-	-	-	1,336,826.16	8,012.15	
10060965	PUC STORM - AUG 6 2024	699,140.95		699,140.95	877,415.24	-	-	617.85	4,003.36	4,621.21	-	-	1,757.55	1,757.55	-	-	849.29	-	867,562.90		-	-	-	-	-	-	877,415.24	3,338.21	
10060966	PUC STORM - AUG 6 2024	10,142,832.02		4,635,268.79	5,507,363.23	-	-	162.91	(0.05)	1,629.08	-	-	8,171.92	8,171.92	38,565.01	-	1,945.04	40,500.95	5,471,538.98		(2,830.71)	-	-	-	-	-	5,507,363.23	14,578.80	
10060967	PUC STORM - NOV 8, 2024	811,455.44		417,121.56	394,333.88	-	-	31.45	-	31.45	-	-	31.45	31.45	-	-	24,269.27	-	394,333.88		-	-	-	-	-	-	394,333.88	107,187.34	
10070872	PUC STORM - DEC 11, 2024	7,290,384.67		3,568,164.78	3,722,219.89	-	-	196,490.34	256,777.22	453,267.56	-	-	166,672.15	166,672.15	60,614.36	-	93,457.10	154,071.46	3,446,555.92		(41,727.61)	-	-	-	-	-	3,722,219.89	497,347.20	
10070871	PUC STORM - NOV 21, 2024	2,459,141.03		2,459,141.03	-	-	-	-	-	-	-	-	111,400.48	111,400.48	-	-	-	(2,662.62)	(2,662.62)	-	-	-	-	-	-	-	-	109,337.86	
12943666	STMF-PUC-STORM-2023AF-26787N	7,001.12		6,911.45	89.67	-	89.67	495.10	-	495.10	-	-	161.40	161.40	-	-	110.90	110.90	89.67		-	-	-	-	-	-	89.67	767.40	
12943680	STMF-PUC-STORM-2023AF-40850N	5,548.00		5,548.00	-	-	-	-	-	-	-	-	102.51	102.51	-	-	-	-	-		-	-	-	-	-	-	-	102.51	
12945014	STMF-37362N409J-2700Z-QMS 6	4,199.72		4,199.72	-	-	-	-	-	-	-	-	195.10	195.10	-	-	-	-	-		-	-	-	-	-	-	-	195.10	
13007327	STMF-40726S870N-47103-40951	8,786.19		8,482.02	304.17	-	304.17	-	-	-	-	-	108.89	108.89	-	-	-	-	304.17		-	-	-	-	-	-	304.17	108.89	
13007694	STMF PUC STORM 2023BG 8-7-20	1,339.92		1,337.03	-	-	-	-	-	-	-	-	1.03	2.89	-	-	(2.70)	(2.70)	-		-	-	-	-	-	-	-	2.89	
13007755	STMF PUC STORM 2023BG 8-7-20	6,730.52		3,605.60	-	-	-	-	-	-	-	-	1,118.72	1,118.72	-	-	-	-	3,124.92		-	-	-	-	-	-	3,124.92	1,118.72	
13013433	STMF PUC STORM 2023BK 09-47	14,922.98		14,922.98	-	-	-	-	-	-	-	-	453.10	453.10	-	-	-	-	1,265.64		-	-	-	-	-	-	1,265.64	453.10	
13013466	STMF-32476S309N-41803-POLE	21,314.60		19,745.47	-	-	-	-	-	-	-	-	433.08	433.08	-	-	-	-	1,569.13		-	-	-	-	-	-	1,569.13	-	
13013796	ECOS-STMF PUC STORM 2023BK 9	528.22		528.22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	28.07	
13014040	STMF PUC STORM 2023BK 8-7-20	242.26		242.26	-	-	-	-	-	-	-	-	17.64	17.64	-	-	-	-	49.27		-	-	-	-	-	-	49.27		

2025 Storm Cost Detail
Year to Date 10/1/2025 (including 11/30/2024 and 12/31/2024)

Storm ID	Description	Grand Total			Total Capital			Total			Payroll			PPL Overheads			Other Allocated Expenses			Remaining			Other Non Recoverable Expenses			TOTAL RECOVERABLE		TOTAL NON - RECOVERABLE	
		Cost		Cost (B)	Expense	ST - straight time		OT - overtime	Total	Other OH		PPL Overheads		Employee Expense (A)		Transportation (B)	Total	Expenses (C)		ST wages from CATGA (Tab D)	BI 13303	BI 34000	Total	STORM EXPENSE (D)	STORM EXPENSE				
13090545	STMP PUC STORM 2024AP 06-26-	23,449.98		23,369.69		80.29		85.99		85.99			59.51	59.51			20.02	20.02		80.29				80.29		165.51			
13090547	STMP-6003747063-11201-QMS 7	2,893.31		2,781.31		112.00		161.94		161.94			98.08	98.08			77.28	77.28		112.00				112.00		337.30			
13090597	STMP PUC STORM 2024AP 06-26-	207,722.61		203,394.72		3,327.88		3,309.99		3,309.99			108.13	108.13			-	-		387.89				387.89		111.22			
13090609	STMP-64934547914-11201-QMS 7	6,224.72		1,036.32		5,188.40		-		-			-	-			-	-		5,188.40				5,188.40		1,186.40			
13090615	STMP PUC STORM 2024AP 06-26-	5,493.51		5,261.03		232.48		5.50		5.50			80.86	80.86			-	-		232.48				232.48		36.36			
13090645	STMP-40393258031-05203-REPLA	1,399.64		1,399.64		-		-		-			-	-			0.35	0.35		-				-	-		0.35		
13092749	STMP-OH-46215841396-1361-OH	155.17		155.17		-		84.50		84.50			23.32	23.32			11.65	11.65		-				-	-		119.47		
13095288	STMP-35048926296-40891-POLE-	15,615.08		14,483.85		1,131.23		-		-			404.98	404.98			8.08	8.08		1,131.23				1,131.23		413.06			
13095711	STMP-OH-44247344894-12301-OH	44,033.71		42,903.07		1,130.64		-		-			1,536.91	1,536.91			-	-		4,293.07				4,293.07		1,536.91			
13095945	STMP-64460484916-14201-QMS 7	330.12		330.12		-		1.93		1.93			220.44	220.44			0.17	0.17		-				-	-		322.54		
13095973	STMP PUC STORM 2024AP 06-26-	3,002.14		3,007.43		14.71		-		-			5.27	5.27			-	-		14.71				14.71		5.27			
13100061	ECOS-STMP-22811533914-54502-	85,547.98		28,924.73		63.25		174.80		174.80			86.22	86.22			56.20	56.20		63.25				63.25		316.22			
13101122	STMP-OH-3P-POLE-13122355689	6,654.58		6,654.10		0.48		2.02		2.02			0.89	0.89			0.63	0.63		0.48				0.48		3.54			
13101201	STMP-22469530338-57304-OH NE	9,989.79		9,985.50		4.29		-		-			-	-			-	-		9,985.50				9,985.50		-			
13101202	STMP-PUC Storm 2024AW-58175N	1,037.61		1,037.61		-		-		-			157.17	157.17			-	-		-				-	-		157.17		
13101233	STMP-39840824845-13202-QMS 7	10,995.50		10,935.51		59.99		147.43		147.43			54.77	54.77			23.35	23.35		-				-	-		255.55		
13101283	ECOS-STMP-57765-STMP-SPH-204-64751	54,581.36		52,319.18		2,062.18		-		-			732.03	732.03			-	-		2,062.18				2,062.18		732.03			
13101319	STMP-PUC Storm 2024AW-49538N	5,749.65		5,727.32		22.33		25.46		25.46			7.61	7.61			5.53	5.53		22.33				22.33		38.60			
13597005	STMP-PUC Storm 2024AW-46228S	16,222.84		14,764.03		1,458.81		-		-			522.26	522.26			-	-		1,458.81				1,458.81		522.26			
13810553	STMP-IPH-OH-604626N3233-1889	9,794.43		9,729.76		554.67		-		-			198.58	198.58			-	-		554.67				554.67		198.58			
13813401	STMP-64994548038-11201-QMS 7	1,744.77		1,744.77		-		41.53		41.53			11.59	11.59			6.81	6.81		-				-	-		59.93		
13822501	STMP-64591548376-14201-QMS 7	(60.21)		(60.21)		-		37.71		37.71			13.50	13.50			4.62	4.62		-				-	-		55.83		
13822719	STMP PUC STORM 2024AW 08-09-	914.81		914.81		-		11.07		11.07			3.97	3.97			2.87	2.87		-				-	-		17.91		
13831073	STMP PUC STORM 2024AW 08-09-	1,305.91		1,053.10		252.81		-		-			90.50	90.50			-	-		252.81				252.81		90.50			
13882587	STMP-25433283630-57304-POLE	6,457.91		6,447.41		10.50		255.05		255.05			74.71	74.71			42.28	42.28		-				-	-		372.04		
13882654	STMP-OH-4698935346-13302-OH	16,490.09		16,490.09		-		9.93		9.93			3,643.31	3,643.31			1.09	1.09		3,643.31				3,643.31		186.60			
13882697	STMP-OH-439779N534423-12101-OH	18,891.75		16,346.02		2,545.73		-		-			529.73	529.73			-	-		2,545.73				2,545.73		292.43			
13883213	STMP-IPH-OH-43145N34736-1860	13,558.83		12,748.08		810.75		-		-			140.96	140.96			-	-		810.75				810.75		140.96			
13883229	STMP-IPH-OH-4342N325718-1860	16,660.72		16,027.24		633.48		-		-			147.24	147.24			-	-		633.48				633.48		147.24			
13883295	STMP-OH-44323N41873-20701-OH	2,562.02		2,562.02		-		203.57		203.57			66.18	66.18			32.68	32.68		-				-	-		292.43		
13883415	STMP-IPH-OH-45330N30291-1350	141.56		141.56		-		653.62		653.62			180.40	180.40			126.87	126.87		-				-	-		960.89		
13883597	STMP-IPH-OH-43104N36029-0310	25,308.87		23,267.27		2,039.60		-		-			223.48	223.48			-	-		2,039.60				2,039.60		223.48			
13883593	STMP-IPH-OH-429N3283758-1858	1,694.15		1,694.15		-		184.19		184.19			36.06	36.06			-	-		-				-	-		217.08		
13883964	STMP-DFOU-IPH-OH-425N135487	32,729.74		31,762.41		967.33		-		-			142.78	142.78			-	-		967.33				967.33		1,179.11			
13872465	STMP-IPH-OH-61051N4302-6105	19,714.57		19,237.08		477.49		-		-			131.79	131.79			-	-		477.49				477.49		131.79			
10070873	PUC STORM - FEB 16, 2025	13,325.02		7,446,675.35		-		61,421.12		1,012,913.53			1,074,344.65	345,923.84	345,923.84		217,718.43	129,517.39	347,235.82	6,230,256.36		(12,221.55)					6,230,256.36		540,959.89
10070774	PUC STORM - MARCH 16, 2025	8,087,471.26		3,874,669.05		4,212,802.21		173,210.80		516,782.44			689,973.24	228,206.62	228,206.62		50,148.91	84,663.04	144,811.95	3,670,010.29		(24,119.43)					4,212,802.21		118,599.88
10075231	PUC STORM - APRIL 15, 2025	4,347,837.66		2,137,221.46		2,210,616.20		152,395.99		293,013.35			445,409.34	131,539.69	131,539.69		16,676.01	67,340.38	84,016.39	1,927,932.74		(27,005.90)					2,210,616.20		378,281.96
10075232	PUC STORM - APRIL 29, 2025	4,367,535.87		2,106,640.13		2,257,895.74		137,875.79		284,711.48			422,587.27	124,128.44	124,128.44		41,292.30	60,082.64	101,374.94	1,949,426.65		(17,534.69)					2,257,895.74		339,621.56
12719497	STMP STORM - 11/30/2022 - LAN	792.06		391.04		401.02		-		-			520.07	520.07			-	-		391.02				-	-		2,942.95		
12935073	STMP-OH-20593N26861-45004-RE	259.68		259.68		-		1,884.31		1,884.31			538.57	538.57			-	-		-				-	-		2,942.95		
13071456	STMP-PUC STORM 2024AS-11392b	13,029.04		12,541.27		487.77		-		-			134.61	134.61			-	-		487.77				487.77		134.61			
13090276	STMP-OH-43165N45516-13802-OH	3,306.74		3,306.74		-		44.37		44.37			15.86	15.86			7.12	7.12		-				-	-		67.37		
13090963	STMP-OH-42007547832-14602-PJ	2,906.45		2,906.45		-		214.86		214.86			59.29	59.29			40.88	40.88		-				-	-		315.03		
13097618	STMP-66896549966-11404-QMS 7	5,311.16		5,087.51		223.65		442.49		442.49			183.87	183.87			64.67	64.67		223.65				223.65		691.03			
13844259	STMP PUC STORM 2024AW 08-09-	1,401.84		1,401.84		-		57.83		57.83			35.35	35.35			27.01	27.01		1,401.84				1,401.84		184.86			
13862701	STMP-OH-48925N52																												

2024 Storm Cost Detail

February 2024 Winter Storm Detail

Storm ID	Description	not recoverable			not recoverable recoverable			not recoverable		recoverable not recoverable			recoverable not recoverable		TOTAL RECOVERABLE	TOTAL NON - RECOVERABLE
		Grand Total	Total Capital	Total	Payroll			PPL Overheads		Other Allocated Expenses			Remaining	ST wages from CATGA (Tab D)		
		Cost	Cost (D)	Expense	ST - straight time	OT - overtime	Total	Other OH	Total	Employee Expense (A)	Transportation (B)	Total	Expenses (C)			
10066352	PUC STORM - FEB 13, 2024	28,657,514.62	12,668,005.38	15,989,509.24	862,313.04	1,066,203.75	1,928,516.79	2,320,052.87	2,320,052.87	459,873.25	252,939.30	712,812.55	11,028,127.03	(188,015.36)	12,366,188.67	3,623,320.57
		28,657,514.62	12,668,005.38	15,989,509.24	862,313.04	1,066,203.75	1,928,516.79	2,320,052.87	2,320,052.87	459,873.25	252,939.30	712,812.55	11,028,127.03	(188,015.36)	12,366,188.67	3,623,320.57

- (A) Employee expenses include hotels, meals and car mileage.
- (B) Transportation represents vehicle and equipment usage, not recoverable
- (C) Remaining expenses includes contractor expenses.
- (D) Recoverable storm cost total excludes capital, PPL straight-time wages, PPL overheads on straight-time, and transportation.

November 2024 Winter Storm Detail

Storm ID	Description	not recoverable			not recoverable recoverable			not recoverable		recoverable not recoverable			recoverable not recoverable		TOTAL RECOVERABLE	TOTAL NON - RECOVERABLE
		Grand Total	Total Capital	Total	Payroll			PPL Overheads		Other Allocated Expenses			Remaining	ST wages from CATGA (Tab D)		
		Cost	Cost (D)	Expense	ST - straight time	OT - overtime	Total	Other OH	Total	Employee Expense (A)	Transportation (B)	Total	Expenses (C)			
10070871	PUC STORM - Nov 21, 2024	18,059,411.01	17,571,638.57	487,772.44	489,826.91	1,559,260.39	2,049,087.30	721,220.22	721,220.22	955,452.69	254,807.79	1,210,260.48	18,351,932.55	(149,158.92)	20,717,486.71	1,615,013.84
		18,059,411.01	17,571,638.57	487,772.44	489,826.91	1,559,260.39	2,049,087.30	721,220.22	721,220.22	955,452.69	254,807.79	1,210,260.48	18,351,932.55	(149,158.92)	20,717,486.71	1,615,013.84

- (A) Employee expenses include hotels, meals and car mileage.
- (B) Transportation represents vehicle and equipment usage, not recoverable
- (C) Remaining expenses includes contractor expenses.
- (D) Recoverable storm cost total excludes capital, PPL straight-time wages, PPL overheads on straight-time, and transportation.

Attachment A

PPL ELECTRIC UTILITIES CORPORATION
STORM DAMAGE EXPENSE RIDER (SDER) COLLECTION RECONCILIATION
Report For The Period November 1, 2024 to October 31, 2025

Line No.		Residential	Small C&I	Large C&I - Primary	Large C&I - Transmission	Total
1	kWh (Schedule 4)	14,575,363,022	10,247,011,678			24,822,374,700
2	kW					
3	Customer Count (Schedule 4)			14,594	1,961	16,555
	Revenue					
4	Current Rate Revenue (Schedule 2, Row 4, Column M)	\$ 19,973,379	\$ 7,113,742	\$ 1,328,804	\$ 144,956	\$ 28,560,881
	Expense					
5	Expenses to be Recovered - (Schedule 2, Row 5, Column M)	\$ 16,660,330	\$ 5,927,154	\$ 1,156,640	\$ 120,072	\$ 23,864,196
6	Expenses to be Recovered - Interest - (Schedule 2, Row 6, Column M)	\$ 2,002,423	\$ 713,450	\$ 140,059	\$ 14,538	\$ 2,870,471
7	Feb Storm Amortization - (Schedule 2, Row 7, Column M)	\$ 2,361,012	\$ 846,306	\$ 166,167	\$ 17,248	\$ 3,390,733
8	Current Over/(Under) SDER	<u>\$ (1,050,386)</u>	<u>\$ (373,168)</u>	<u>\$ (134,062)</u>	<u>\$ (6,902)</u>	<u>\$ (1,564,519)</u>
9	Interest on Current Over/(Under) Collection (Schedule 5, Page 1, Line 13)	\$ (110,186)	\$ (40,033)	\$ (12,595)	\$ (809)	\$ (163,623)
10	Total Over/(Under) Collection	<u>\$ (1,160,572)</u>	<u>\$ (413,201)</u>	<u>\$ (146,657)</u>	<u>\$ (7,711)</u>	<u>\$ (1,728,142)</u>
11	Prior Year Remaining (Schedule 3, Line 13)	\$ (123,294)	\$ (47,057)	\$ (12,159)	\$ (1,153)	\$ (183,663)
12	Total Over/(Under) Collection	<u>\$ (1,283,866)</u>	<u>\$ (460,258)</u>	<u>\$ (158,816)</u>	<u>\$ (8,865)</u>	<u>\$ (1,911,805)</u>

PPL ELECTRIC UTILITIES CORPORATION
STORM DAMAGE EXPENSE RIDER (SDER) COLLECTION RECONCILIATION
Residential
Report For The Period November 1, 2024 to October 31, 2025

Line No.	(A) November 2024	(B) December 2024	(C) January 2025	(D) February 2025	(E) March 2025	(F) April 2025	(G) May 2025	(H) June 2025	(I) July 2025	(J) August 2025	(K) September 2025	(L) October 2025	(M) Total
1 kWh (Schedule 4)	873,963,064	1,360,534,200	1,787,045,710	1,821,597,424	1,384,060,941	1,063,515,531	897,151,058	930,991,472	1,298,599,533	1,276,944,925	1,015,108,484	865,850,680	14,575,363,022
2 kW													
3 Customer Count													
Revenue (Schedule 4)													
4 Current Rate Revenue	\$ 156,181	\$ 243,261	\$ 1,427,313	\$ 3,128,616	\$ 2,380,584	\$ 1,829,313	\$ 1,542,745	\$ 1,601,006	\$ 2,233,216	\$ 2,196,097	\$ 1,745,588	\$ 1,489,459	\$ 19,973,379
Expense													
5 Expenses to be Recovered	\$ 192,808	\$ 221,998	\$ 2,290,389	\$ 2,098,246	\$ 1,740,449	\$ 1,352,287	\$ 1,314,402	\$ 1,431,492	\$ 1,782,577	\$ 1,709,690	\$ 1,275,734	\$ 1,250,258	\$ 16,660,330
6 Expenses to be Recovered - Interest	\$ 35,589	\$ 40,977	\$ 271,518	\$ 248,741	\$ 206,325	\$ 160,309	\$ 155,818	\$ 169,699	\$ 211,319	\$ 202,678	\$ 151,234	\$ 148,214	\$ 2,002,423
7 Feb 13th Storm Amortization	\$ -	\$ -	\$ 332,869	\$ 304,945	\$ 252,945	\$ 196,532	\$ 191,026	\$ 208,043	\$ 259,067	\$ 248,475	\$ 185,406	\$ 181,704	\$ 2,361,012
8 Current Over/(Under) SDER	\$ (72,216)	\$ (19,714)	\$ (1,467,463)	\$ 476,684	\$ 180,865	\$ 120,184	\$ (118,501)	\$ (208,228)	\$ (19,747)	\$ 35,253	\$ 133,214	\$ (90,718)	\$ (1,050,386)

PPL ELECTRIC UTILITIES CORPORATION
STORM DAMAGE EXPENSE RIDER (SDER) COLLECTION RECONCILIATION
Small Commercial and Industrial
Report For The Period November 1, 2024 to October 31, 2025

Line No.	(A) November 2024	(B) December 2024	(C) January 2025	(D) February 2025	(E) March 2025	(F) April 2025	(G) May 2025	(H) June 2025	(I) July 2025	(J) August 2025	(K) September 2025	(L) October 2025	(M) Total
1 kWh (Schedule 4)	742,012,722	860,212,061	943,728,498	958,691,190	834,888,139	770,253,116	780,833,187	798,887,980	948,674,526	943,493,391	865,186,329	800,150,539	10,247,011,678
2 kW													
3 Customer Count													
Revenue													
4 Current Rate Revenue (Schedule 4)	\$ 65,955	\$ 76,505	\$ 358,465	\$ 821,761	\$ 714,137	\$ 661,103	\$ 670,622	\$ 686,673	\$ 816,032	\$ 811,559	\$ 744,025	\$ 686,906	\$ 7,113,742
Expense													
5 Expenses to be Recovered	\$ 60,013	\$ 65,272	\$ 634,476	\$ 566,926	\$ 579,586	\$ 509,852	\$ 546,241	\$ 581,804	\$ 645,934	\$ 638,187	\$ 560,909	\$ 537,955	\$ 5,927,154
6 Expenses to be Recovered - Interest	\$ 11,078	\$ 12,048	\$ 75,492	\$ 67,455	\$ 68,961	\$ 60,664	\$ 64,993	\$ 69,225	\$ 76,855	\$ 75,933	\$ 66,739	\$ 64,008	\$ 713,450
7 Feb 13th Storm Amortization	\$ -	\$ -	\$ 92,550	\$ 82,696	\$ 84,543	\$ 74,371	\$ 79,679	\$ 84,866	\$ 94,221	\$ 93,091	\$ 81,819	\$ 78,470	\$ 846,306
8 Current Over/(Under) SDER	\$ (5,135)	\$ (815)	\$ (444,053)	\$ 104,684	\$ (18,953)	\$ 16,217	\$ (20,291)	\$ (49,222)	\$ (979)	\$ 4,348	\$ 34,558	\$ 6,473	\$ (373,168)

PPL ELECTRIC UTILITIES CORPORATION
STORM DAMAGE EXPENSE RIDER (SDER) COLLECTION RECONCILIATION
Large Commercial and Industrial Primary
Report For The Period November 1, 2024 to October 31, 2025

Line No.		(A) November 2024	(B) December 2024	(C) January 2025	(D) February 2025	(E) March 2025	(F) April 2025	(G) May 2025	(H) June 2025	(I) July 2025	(J) August 2025	(K) September 2025	(L) October 2025	(M) Total
1	kWh													
2	kW													
3	Customer Count (Schedule 4)	1,221	1,204	1,218	1,220	1,231	1,203	1,207	1,181	1,193	1,275	1,225	1,216	14,594
	Revenue													
4	Current Rate Revenue (Schedule 4)	\$ 14,315	\$ 14,109	\$ 58,582	\$ 135,311	\$ 138,891	\$ 137,000	\$ 137,384	\$ 134,337	\$ 135,907	\$ 144,915	\$ 139,418	\$ 138,634	\$ 1,328,804
	Expense													
5	Expenses to be Recovered	\$ 12,204	\$ 12,273	\$ 112,305	\$ 108,246	\$ 115,102	\$ 111,042	\$ 113,298	\$ 113,478	\$ 113,929	\$ 116,635	\$ 109,509	\$ 118,620	\$ 1,156,640
6	Expenses to be Recovered - Interest	\$ 2,253	\$ 2,265	\$ 13,445	\$ 12,959	\$ 13,780	\$ 13,294	\$ 13,564	\$ 13,585	\$ 13,639	\$ 13,963	\$ 13,110	\$ 14,201	\$ 140,059
7	Feb 13th Storm Amortization	\$ -	\$ -	\$ 16,483	\$ 15,887	\$ 16,893	\$ 16,298	\$ 16,629	\$ 16,655	\$ 16,721	\$ 17,118	\$ 16,073	\$ 17,410	\$ 166,167
8	Current Over/(Under) SDER	<u>\$ (141)</u>	<u>\$ (429)</u>	<u>\$ (83,651)</u>	<u>\$ (1,781)</u>	<u>\$ (6,883)</u>	<u>\$ (3,634)</u>	<u>\$ (6,107)</u>	<u>\$ (9,381)</u>	<u>\$ (8,382)</u>	<u>\$ (2,802)</u>	<u>\$ 726</u>	<u>\$ (11,596)</u>	<u>\$ (134,062)</u>

PPL ELECTRIC UTILITIES CORPORATION
STORM DAMAGE EXPENSE RIDER (SDER) COLLECTION RECONCILIATION
Large Commercial and Industrial Transmission
Report For The Period November 1, 2024 to October 31, 2025

Line No.		(A) November 2024	(B) December 2024	(C) January 2025	(D) February 2025	(E) March 2025	(F) April 2025	(G) May 2025	(H) June 2025	(I) July 2025	(J) August 2025	(K) September 2025	(L) October 2025	(M) Total
1	kWh													
2	kW													
3	Customer Count (Schedule 4)	152	140	187	156	175	169	170	162	162	163	161	164	1,961
Revenue														
4	Current Rate Revenue (Schedule 4)	\$ 1,451	\$ 1,371	\$ 5,453	\$ 13,491	\$ 15,501	\$ 15,136	\$ 15,739	\$ 15,671	\$ 15,262	\$ 15,296	\$ 15,225	\$ 15,360	\$ 144,956
Expense														
5	Expenses to be Recovered	\$ 1,260	\$ 1,268	\$ 11,680	\$ 11,234	\$ 11,978	\$ 11,531	\$ 11,754	\$ 11,754	\$ 11,829	\$ 12,126	\$ 11,382	\$ 12,275	\$ 120,072
6	Expenses to be Recovered - Interest	\$ 233	\$ 236	\$ 1,398	\$ 1,345	\$ 1,434	\$ 1,380	\$ 1,407	\$ 1,407	\$ 1,416	\$ 1,452	\$ 1,362	\$ 1,469	\$ 14,538
7	Feb 13th Storm Amortization	\$ -	\$ -	\$ 1,714	\$ 1,648	\$ 1,758	\$ 1,692	\$ 1,725	\$ 1,725	\$ 1,736	\$ 1,779	\$ 1,670	\$ 1,801	\$ 17,248
8	Current Over/(Under) SDER	<u>\$ (42)</u>	<u>\$ (133)</u>	<u>\$ (9,339)</u>	<u>\$ (735)</u>	<u>\$ 332</u>	<u>\$ 533</u>	<u>\$ 853</u>	<u>\$ 785</u>	<u>\$ 282</u>	<u>\$ (61)</u>	<u>\$ 810</u>	<u>\$ (186)</u>	<u>\$ (6,902)</u>

PPL ELECTRIC UTILITIES CORPORATION
STORM DAMAGE EXPENSE RIDER (SDER) COLLECTION RECONCILIATION
E-Factor Collection Balance
Report For The Period November 1, 2024 to October 31, 2025

Line No.	(A) Residential		(B) Over/(Under)		(C) Small C&I		(D) Over/(Under)		(E) Large C&I - Primary		(F) Over/(Under)		(G) Large C&I - Transmission		(H) Over/(Under)		(I) Total		(J) Over/(Under)	
	(Refund)/ Recovery		Over/(Under) Balance		(Refund)/ Recovery		Over/(Under) Balance		(Refund)/ Recovery		Over/(Under) Balance		(Refund)/ Recovery		Over/(Under) Balance		(Refund)/ Recovery		Over/(Under) Balance	
1 E-Factor Balance - October 31, 2024	\$	-	\$	(154,024)	\$	-	\$	(79,365)	\$	-	\$	(23,967)	\$	-	\$	(2,454)			\$	(259,810)
2 November 2024	\$	(41,076)	\$	(195,100)	\$	(17,066)	\$	(96,431)	\$	(3,858)	\$	(27,825)	\$	(453)	\$	(2,907)	\$	(62,453)	\$	(322,263)
3 December 2024	\$	(63,945)	\$	(259,045)	\$	(19,785)	\$	(116,216)	\$	(3,805)	\$	(31,630)	\$	(417)	\$	(3,324)	\$	(87,952)	\$	(410,215)
4 January 2025	\$	19,658	\$	(239,387)	\$	7,550	\$	(108,666)	\$	1,949	\$	(29,681)	\$	243	\$	(3,081)	\$	29,400	\$	(380,815)
5 February 2025	\$	20,038	\$	(219,349)	\$	7,670	\$	(100,996)	\$	1,952	\$	(27,729)	\$	203	\$	(2,878)	\$	29,863	\$	(350,952)
6 March 2025	\$	15,225	\$	(204,124)	\$	6,679	\$	(94,317)	\$	1,970	\$	(25,759)	\$	228	\$	(2,650)	\$	24,102	\$	(326,850)
7 April 2025	\$	11,699	\$	(192,425)	\$	6,162	\$	(88,155)	\$	1,925	\$	(23,834)	\$	220	\$	(2,430)	\$	20,006	\$	(306,844)
8 May 2025	\$	9,869	\$	(182,556)	\$	6,247	\$	(81,908)	\$	1,931	\$	(21,903)	\$	221	\$	(2,209)	\$	18,268	\$	(288,576)
9 June 2025	\$	10,241	\$	(172,315)	\$	6,391	\$	(75,517)	\$	1,890	\$	(20,013)	\$	211	\$	(1,998)	\$	18,732	\$	(269,844)
10 July 2025	\$	14,285	\$	(158,031)	\$	7,589	\$	(67,928)	\$	1,909	\$	(18,104)	\$	211	\$	(1,788)	\$	23,993	\$	(245,851)
11 August 2025	\$	14,046	\$	(143,984)	\$	7,548	\$	(60,380)	\$	2,040	\$	(16,064)	\$	212	\$	(1,576)	\$	23,846	\$	(222,005)
12 September 2025	\$	11,166	\$	(132,818)	\$	6,921	\$	(53,458)	\$	1,960	\$	(14,104)	\$	209	\$	(1,367)	\$	20,257	\$	(201,748)
13 October 2025	\$	9,524	\$	(123,294)	\$	6,401	\$	(47,057)	\$	1,946	\$	(12,159)	\$	213	\$	(1,153)	\$	18,084	\$	(183,663)

PPL ELECTRIC UTILITIES CORPORATION
SUMMARY OF ALLOCATION OF STORM DAMAGE EXPENSE RIDER - REVENUES
Report For The Period November 1, 2024 to October 31, 2025

Residential		(A)	(B)	(C)	(D)	(E)
Month		KWH	SDER Total Revenues	(Excl. Gross Receipts Tax)	Recouped Through E Factor \$0.000011 /KWh (B)	Net Revenue
November	2024	873,963,064	\$ 122,322	\$ 115,105	\$ (41,076) (A)	\$ 156,181
December	2024	1,360,534,200	\$ 190,560	\$ 179,316	\$ (63,945) (A)	\$ 243,261
January	2025	1,787,045,710	\$ 1,537,695	\$ 1,446,971	\$ 19,658 (B)	\$ 1,427,313
February	2025	1,821,597,424	\$ 3,346,072	\$ 3,148,654	\$ 20,038 (B)	\$ 3,128,616
March	2025	1,384,060,941	\$ 2,546,024	\$ 2,395,809	\$ 15,225 (B)	\$ 2,380,584
April	2025	1,063,515,531	\$ 1,956,442	\$ 1,841,012	\$ 11,699 (B)	\$ 1,829,313
May	2025	897,151,058	\$ 1,649,962	\$ 1,552,614	\$ 9,869 (B)	\$ 1,542,745
June	2025	930,991,472	\$ 1,712,271	\$ 1,611,247	\$ 10,241 (B)	\$ 1,601,006
July	2025	1,298,599,533	\$ 2,388,417	\$ 2,247,501	\$ 14,285 (B)	\$ 2,233,216
August	2025	1,276,944,925	\$ 2,348,717	\$ 2,210,143	\$ 14,046 (B)	\$ 2,196,097
September	2025	1,015,108,484	\$ 1,866,902	\$ 1,756,754	\$ 11,166 (B)	\$ 1,745,588
October	2025	<u>865,850,680</u>	<u>\$ 1,592,968</u>	<u>\$ 1,498,983</u>	<u>\$ 9,524 (B)</u>	<u>\$ 1,489,459</u>
		<u>14,575,363,022</u>	<u>21,258,352</u>	<u>20,004,109</u>	<u>30,730</u>	<u>19,973,379</u>

(A) - November and December 2024 are amortized at the prior year e-factor rate

(B) - Line 7 Storm Damage Expense Rider Rate filing Schedule B/projected 2025 kWh sales

PPL ELECTRIC UTILITIES CORPORATION
SUMMARY OF ALLOCATION OF STORM DAMAGE EXPENSE RIDER - REVENUES
Report For The Period November 1, 2024 to October 31, 2025

		(A)	(B)	(C)	(D)	(E)
Small C&I						
Month		KWH	SDER Total Revenues	(Excl. Gross Receipts Tax)	Recouped Through E Factor \$0.000008 /KWh (B)	Net Revenue
November	2024	742,012,722	\$ 51,954	\$ 48,889	\$ (17,066) (A)	\$ 65,955
December	2024	860,212,061	\$ 60,276	\$ 56,720	\$ (19,785) (A)	\$ 76,505
January	2025	943,728,498	\$ 388,964	\$ 366,015	\$ 7,550 (B)	\$ 358,465
February	2025	958,691,190	\$ 881,436	\$ 829,431	\$ 7,670 (B)	\$ 821,761
March	2025	834,888,139	\$ 766,011	\$ 720,816	\$ 6,679 (B)	\$ 714,137
April	2025	770,253,116	\$ 709,102	\$ 667,265	\$ 6,162 (B)	\$ 661,103
May	2025	780,833,187	\$ 719,308	\$ 676,869	\$ 6,247 (B)	\$ 670,622
June	2025	798,887,980	\$ 736,518	\$ 693,064	\$ 6,391 (B)	\$ 686,673
July	2025	948,674,526	\$ 875,261	\$ 823,621	\$ 7,589 (B)	\$ 816,032
August	2025	943,493,391	\$ 870,464	\$ 819,107	\$ 7,548 (B)	\$ 811,559
September	2025	865,186,329	\$ 798,030	\$ 750,946	\$ 6,921 (B)	\$ 744,025
October	2025	800,150,539	\$ 736,776	\$ 693,307	\$ 6,401 (B)	\$ 686,906
		<u>10,247,011,678</u>	<u>7,594,102</u>	<u>7,146,050</u>	<u>32,308</u>	<u>7,113,742</u>

(A) - November and December 2024 are amortized at the prior year e-factor rate

(B) - Line 7 Storm Damage Expense Rider Rate filing Schedule B/projected 2025 kWh sales

PPL ELECTRIC UTILITIES CORPORATION
SUMMARY OF ALLOCATION OF STORM DAMAGE EXPENSE RIDER - REVENUES
Report For The Period November 1, 2024 to October 31, 2025

		(A)	(B)	(C)	(D)	(E)
Large C&I - Primary						
Month		Customer Count	SDER Total Revenues	(Excl. Gross Receipts Tax)	Recouped Through E Factor \$1.60 /Customer (B)	Net Revenue
November	2024	1,221	\$ 11,113	\$ 10,457	\$ (3,858) (A)	\$ 14,315
December	2024	1,204	\$ 10,950	\$ 10,304	\$ (3,805) (A)	\$ 14,109
January	2025	1,218	\$ 64,326	\$ 60,531	\$ 1,949 (B)	\$ 58,582
February	2025	1,220	\$ 145,869	\$ 137,263	\$ 1,952 (B)	\$ 135,311
March	2025	1,231	\$ 149,693	\$ 140,861	\$ 1,970 (B)	\$ 138,891
April	2025	1,203	\$ 147,636	\$ 138,925	\$ 1,925 (B)	\$ 137,000
May	2025	1,207	\$ 148,050	\$ 139,315	\$ 1,931 (B)	\$ 137,384
June	2025	1,181	\$ 144,768	\$ 136,227	\$ 1,890 (B)	\$ 134,337
July	2025	1,193	\$ 146,457	\$ 137,816	\$ 1,909 (B)	\$ 135,907
August	2025	1,275	\$ 156,169	\$ 146,955	\$ 2,040 (B)	\$ 144,915
September	2025	1,225	\$ 150,242	\$ 141,378	\$ 1,960 (B)	\$ 139,418
October	2025	1,216	\$ 149,394	\$ 140,580	\$ 1,946 (B)	\$ 138,634
		<u>14,594</u>	<u>1,424,668</u>	<u>1,340,612</u>	<u>11,808</u>	<u>1,328,804</u>

(A) - November and December 2024 are amortized at the prior year e-factor rate

(B) - Line 7 Storm Damage Expense Rider Rate filing Schedule B/projected 2025 customer count

PPL ELECTRIC UTILITIES CORPORATION
SUMMARY OF ALLOCATION OF STORM DAMAGE EXPENSE RIDER - REVENUES
Report For The Period November 1, 2024 to October 31, 2025

		(A)	(B)	(C)	(D)	(E)
Large C&I - Transmission						
Month		Customer Count	SDER Total Revenues	(Excl. Gross Receipts Tax)	Recouped Through E Factor \$1.30 /Customer (B)	Net Revenue
November	2024	152	\$ 1,061	\$ 998	\$ (453) (A)	\$ 1,451
December	2024	140	\$ 1,014	\$ 954	\$ (417) (A)	\$ 1,371
January	2025	187	\$ 6,053	\$ 5,696	\$ 243 (B)	\$ 5,453
February	2025	156	\$ 14,553	\$ 13,694	\$ 203 (B)	\$ 13,491
March	2025	175	\$ 16,715	\$ 15,729	\$ 228 (B)	\$ 15,501
April	2025	169	\$ 16,319	\$ 15,356	\$ 220 (B)	\$ 15,136
May	2025	170	\$ 16,960	\$ 15,960	\$ 221 (B)	\$ 15,739
June	2025	162	\$ 16,878	\$ 15,882	\$ 211 (B)	\$ 15,671
July	2025	162	\$ 16,443	\$ 15,473	\$ 211 (B)	\$ 15,262
August	2025	163	\$ 16,480	\$ 15,508	\$ 212 (B)	\$ 15,296
September	2025	161	\$ 16,402	\$ 15,434	\$ 209 (B)	\$ 15,225
October	2025	164	\$ 16,550	\$ 15,573	\$ 213 (B)	\$ 15,360
		<u>1,961</u>	<u>155,428</u>	<u>146,257</u>	<u>1,301</u>	<u>144,956</u>

(A) - November and December 2024 are amortized at the prior year e-factor rate

(B) - Line 7 Storm Damage Expense Rider Rate filing Schedule B/projected 2025 customer count

PPL ELECTRIC UTILITIES CORPORATION
INTEREST EXPENSE ON STORM DAMAGE EXPENSE RIDER
OVER/(UNDER) COLLECTIONS BY MONTH

Line No.	Month	(A) Interest Rate	(B) Weighting Factor	(C)		(D)		(E)		(F)		(G)		(H)		(I)		(J)		(K)		(L)	
				Total		Residential		Small Commercial and Industrial		Large Commercial and Industrial Primary		Large Commercial and Industrial Transmission											
				Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection	Over/(Under) Collection Total	Interest on Over/(Under) Collection
1	November 2024	Fm 6.50%	20/12	\$ (77,535)	\$ (8,399)	\$ (72,216)	\$ (7,823)	\$ (5,135)	\$ (556)	\$ (141)	\$ (15)	\$ (42)	\$ (5)										
2	December 2024	6.75%	19/12	\$ (21,092)	\$ (2,254)	\$ (19,714)	\$ (2,107)	\$ (815)	\$ (87)	\$ (429)	\$ (46)	\$ (133)	\$ (14)										
3	January 2025	7.00%	18/12	\$ (2,004,506)	\$ (210,474)	\$ (1,467,463)	\$ (154,084)	\$ (444,053)	\$ (46,626)	\$ (83,651)	\$ (8,783)	\$ (9,339)	\$ (981)										
4	February 2025	7.00%	17/12	\$ 578,852	\$ 57,402	\$ 476,684	\$ 47,271	\$ 104,684	\$ 10,381	\$ (1,781)	\$ (177)	\$ (735)	\$ (73)										
5	March 2025	7.25%	16/12	\$ 155,360	\$ 15,019	\$ 180,865	\$ 17,484	\$ (18,953)	\$ (1,832)	\$ (6,883)	\$ (665)	\$ 332	\$ 32										
6	April 2025	7.00%	15/12	\$ 133,299	\$ 11,664	\$ 120,184	\$ 10,516	\$ 16,217	\$ 1,419	\$ (3,634)	\$ (318)	\$ 533	\$ 47										
7	May 2025	7.00%	14/12	\$ (144,046)	\$ (11,764)	\$ (118,501)	\$ (9,678)	\$ (20,291)	\$ (1,657)	\$ (6,107)	\$ (499)	\$ 853	\$ 70										
8	June 2025	7.00%	13/12	\$ (266,045)	\$ (20,175)	\$ (208,228)	\$ (15,791)	\$ (49,222)	\$ (3,733)	\$ (9,381)	\$ (711)	\$ 785	\$ 60										
9	July 2025	7.25%	12/12	\$ (28,826)	\$ (2,091)	\$ (19,747)	\$ (1,432)	\$ (979)	\$ (71)	\$ (8,382)	\$ (608)	\$ 282	\$ 20										
10	August 2025	7.25%	11/12	\$ 36,739	\$ 2,442	\$ 35,253	\$ 2,343	\$ 4,348	\$ 289	\$ (2,802)	\$ (186)	\$ (61)	\$ (4)										
11	September 2025	7.25%	10/12	\$ 169,308	\$ 10,229	\$ 133,214	\$ 8,048	\$ 34,558	\$ 2,088	\$ 726	\$ 44	\$ 810	\$ 49										
12	October 2025	7.25%	9/12	\$ (96,026)	\$ (5,222)	\$ (90,718)	\$ (4,933)	\$ 6,473	\$ 352	\$ (11,596)	\$ (631)	\$ (186)	\$ (10)										
13	Total			\$ (1,564,519)	\$ (163,623)	\$ (1,050,386)	\$ (110,186)	\$ (373,168)	\$ (40,033)	\$ (134,062)	\$ (12,595)	\$ (6,902)	\$ (809)										

WITNESS: Katelyn Arnold

PPL Electric Utilities Corporation
Response to the Set II Data Requests of the
Office of Small Business Advocate (OSBA)
Dated December 10, 2025
Docket No. R-2025-3057164

OSBA II-1 Reference the response to OSBA-PPL-I-27(b): please provide the Company's rationale for assessing the SDER on a per-customer basis for Rate LP-4 customers in the rate case at Docket No. R-2012-2290597. Explain why the methodology differed for the LP-4 class compared to other classes for which the SDER is recovered through a per-kWh charge.

PPL Electric Application of the Storm Damage Expense Rider (SDER) on a
Response per-bill basis is consistent with the Company's 2015 Rate Case Settlement Agreement, to which OSBA was a party, as filed on September 3, 2015, at Docket No. R-2015-2469275. On pages 26-27 of its Statement in Support, the Company noted that the base rate structure for the Large C&I customer class contained only a customer charge, i.e., there is no demand component in the Large C&I distribution rate structure. The proposed change made the SDER consistent with the rate structure for the LC&I customer class. The proposal was acceptable to the Joint Petitioners and ultimately approved by the Commission.

WITNESS: Steven W. Wishart
Katelyn Arnold

PPL Electric Utilities Corporation
Response to the Set IV Data Requests of the
Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania
(CAUSE-PA)
Dated October 22, 2025
Docket No. R-2025-3057164

CAUSE-PA IV-8 Refer to PPL Electric Exhibit SWW-1. Please explain which rate classes PPL Electric applies the USR Rider to and the basis for the application of that rider to these rate classes.

PPL Electric At present, the USR applies to Rate Schedules RS and RTS.
Response Customers being charged volunteer rates under Rate Schedules GS-1 and GS-3 pay RS rates and thus pay the USR as well.

As shown on page 50 of PPL Electric Exhibit GEO-1, the Company proposes applying the USR to Rate Schedule RS only, as it is proposing to eliminate the RTS rate schedule. Customers being charged volunteer rates under Rate Schedules GS-1 and GS-3 will continue to pay RS rates and, as a result, pay the USR as well.

Because the USR recovers costs associated with customer assistance programs for which only residential customers are eligible, it is consistent with cost of service principles to recover these costs only from residential customers.

I&E Statement No. 2
Witness: Lisa A Boyd

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-2015-2469275

Direct Testimony

of

Lisa A Boyd

Bureau of Investigation & Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES
TAXES OTHER THAN INCOME
RATE BASE

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1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Lisa A. Boyd. My business address is Pennsylvania Public Utility
3 Commission, P.O. Box 3265, Harrisburg, PA 17105-3265.

4

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

6 A. I am employed by the Pennsylvania Public Utility Commission (Commission) in
7 the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Valuation
8 Engineer.

9

10 **Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?**

11 A. An outline of my education and employment experience is attached as
12 Appendix A.

13

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

15 A. I&E is responsible for protecting the public interest in proceedings before the
16 Commission. The I&E analysis in the proceeding is based on its responsibility to
17 represent the public interest. This responsibility requires the balancing of the
18 interests of the public, ratepayers, and the Company.

19

20 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

21 A. The purpose of my testimony is to review the base rate filing of PPL Electric
22 Utilities Corporation (PPL Electric, PPL, or Company). I am making

recommended adjustments to the Company's proposed operating and maintenance (O&M) expenses for the fully projected future test year (FPFTY) ending December 31, 2016. My recommendations relate to payroll and benefits expense; payroll taxes; rate case expense; environmental remediation expense; affiliate support; gross receipts tax; cash working capital; storm amortization; the merchant function charge; and the purchase of receivables discount rate.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules relating to my testimony.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following tables summarize my recommended adjustments:

STORM AMORTIZATION EXPENSE

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

A. The Company has included \$5,324,000 in amortization expense for 2011 storm costs in base rates. Per the Company response to an OCA interrogatory, OCA-I-13, the 2011 storm cost amortization will continue through December 2017 (I&E Exhibit No. 2, Sch. 11, p. 3).

Q. IS THE 2011 STORM AMORTIZATION EXPENSE THE ONLY STORM AMORTIZATION EXPENSE THAT THE COMPANY HAS INCLUDED IN BASE RATES IN THE FPFTY?

A. Yes. The January 2005 ice storms that were amortized through base rates have been fully amortized in the FTY; thus, there is no claim for this amortization expense in the FPFTY. The Company's costs for Hurricane Sandy in 2012 are being amortized over three years, beginning in 2015, but the amortization expense for Hurricane Sandy is recovered through the Company's Storm Damage Expense Rider (SDER) and is not recovered through base rates. (I&E Exhibit No. 2, Sch. 11, p. 4)

1 **Q. HAS THE COMPANY CORRECTLY CLAIMED ITS STORM**
2 **AMORTIZATION EXPENSE FOR THE FPFTY?**

3 A. Yes. The claimed amortization expense of \$5,324,000, which extends to
4 December 2017, is appropriately classified.

5
6 **Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS**
7 **REGARDING THE CLAIMED AMORTIZATION EXPENSE?**

8 A. Yes. As the claimed amortization expense ends in December 2017, I recommend
9 that any continued recovery of this expense after 2017 be included in the base rate
10 SDER ratepayer contribution beginning in 2018, if the Company has not filed for a
11 base rate case, in order to remove the storm amortization expense from base rates.

12
13 **Q. WHAT IS THE NET EFFECT OF THE ADDITION OF THE**
14 **AMORTIZATION EXPENSE TO THE SDER IN 2018?**

15 A. The Company proposes to maintain the original designated base rate annual storm
16 expense of \$14,700,000 to be offset against actual storm costs when the SDER is
17 reconciled annually (Company Statement No. 4, p. 21). In 2018, inclusion of the
18 expired storm amortization expense would increase the base rate annual storm
19 expense to \$20,024,000 (\$14,700,000 + \$5,324,000). The base rate amount of
20 \$20,024,000 would then be used as the ratepayer contribution to be offset against
21 actual storm costs when the SDER is reconciled. The Company can adjust the

1 base rate storm expense of \$20,024,000 relative to the actual storm experience and
2 SDER history in its next base rate case.

3
4 **MERCHANT FUNCTION CHARGE**

5 **Q. WHAT IS THE COMPANY'S CLAIMED MERCHANT FUNCTION**
6 **CHARGE RATE?**

7 A. The Company proposes a Merchant Function Charge (MFC) rate of 2.42% for its
8 residential customer class. The Company proposes to roll the uncollectible rate for
9 the small C&I class, 0.41%, into base rates due to its small size (Company
10 Statement No. 5, p. 10). In this proceeding, the Company is proposing different
11 MFC rates from the distribution uncollectible rates for the first time.

12 At the last base rate case at Docket No. R-2012-2290597, the Company was
13 directed to perform an analysis to compare uncollectible expense associated with
14 shopping and non-shopping customers to determine if there was a difference. The
15 outcome of that analysis was that uncollectible rates are different between
16 shopping and non-shopping customers. Based on this outcome, the Company is
17 proposing separate rates for its MFC and Purchase of Receivables (POR) discount
18 rates. The Company proposes to adjust these rates annually on June 1st to reflect
19 actual class uncollectible rates (Company Statement No. 5, p. 9, ln. 6-16).

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
GREGORY OLSEN
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Retail Tariff
 Interconnection Process
 Maximum Registered Peak Load**

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Gregory Olsen, and my business address is 827 Hausman Rd. Allentown, PA 18104.

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

A. I am employed by PPL Electric Utilities Corporation (“PPL Electric”), a subsidiary of PPL Corporation (“PPL Corp.”), as Supervisor – Distribution Interconnections & Tariff Rules.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my Rebuttal Testimony is to respond to testimony by various parties related to the Company’s proposed tariff changes, as well as their own proposed revisions to the Company’s tariff, for which I am responsible, in addition to addressing issues concerning the Company’s interconnection process. Specifically, I will respond to testimony from the Coalition for Affordable Utility Service and Energy Efficiency in Pennsylvania (“CAUSE-PA”) Witness Cicero (CAUSE-PA St. No. 1), Energy Justice Advocates (“EJA”) Witness Rábago (“EJA Statement No. 1), the Environmental Intervenors (“EI”) Witness Nelson (EI St. No. 1), Convergent Energy and Power LP (“Convergent”) Witness Guerry (Convergent St. No. 1), Customer Generator Coalition (“CGC”) Witness Sharfman (CGC Statement No.

1 1), Joint Solar Advocates (“JSA”) Witness Lucas (JSA Statement No. 1), and the Professional
2 Dairy Managers of Pennsylvania (“PDMP”) Witness Harbach (PDMP Statement No. 1).

3
4 **Q. Are you sponsoring any exhibits or schedules as part of your rebuttal testimony?**

5 A. Yes, attached to my rebuttal testimony are the following exhibits:

- 6 • PPL Electric Exhibit GEO-1R – Answer to Convergent I-10 and Convergent I-10
7 Attachment 1
- 8 • PPL Electric Exhibit GEO-2R – PDMP Answer to PPL to PDMP-II-11

9
10 **II. TARIFF CHANGES**

11 **Q. Please address CAUSE-PA Witness Cicero’s recommendations regarding the definition**
12 **of “tenant” in the Company’s Tariff. (CAUSE-PA St. No. 1, pp. 118-119.)**

13 A. Mr. Cicero recommends that PPL Electric revise its proposed definition of “tenant” to match
14 the definition in Section 1521 of the Public Utility Code. With respect to CAUSE-PA’s
15 recommendation that the Company revise the definition of “tenant,” the Company does not
16 agree with all of Mr. Cicero’s concerns; however, it concurs that the current proposed
17 definition could be clarified to specify residential and commercial customers and their
18 respective rate classes. To improve this language, PPL Electric proposes updating its Tariff to
19 include the following definition of “tenant”:

20 Any person or group of persons who occupies or is entitled to occupy
21 a residential or commercial unit within a multitenancy building,
22 parcel, or mobile home park and who is contractually obligated to
23 make rental payments to a landlord or landlord ratepayer pursuant to
24 a written or oral lease or rental arrangement. The term includes

1 occupants of residential or commercial units where electric service is
2 provided as an included service under the rental agreement and where
3 the occupant is not the ratepayer of the utility providing such service.
4 For purposes of this definition, a multitenancy building shall include
5 any structure containing three (3) or more separate and distinct
6 residential or commercial units, and tenancy may be expected to be for
7 a duration of one (1) year or more.
8

9 The Company submits that this revision sufficiently addresses the concerns raised by
10 CAUSE-PA.
11

12 **Q. How does CAUSE-PA Witness Cicero summarize the Company's proposals related to**
13 **submetering?**

14 A. Mr. Cicero fairly summarizes the Company's proposed changes to how it "will allow the
15 redistribution of its service from a master-meter to non-utility owned sub-meters." (CAUSE-
16 PA St. No. 1, p. 119.) He also correctly notes that the Company is proposing to "allow
17 submetering where it 'is neither feasible nor practical from a financial, technical, engineering,
18 and/or any other valid reason'" and that any exceptions will be approved in the case where
19 the master meter is designed such that it will not achieve a notable reduction electricity
20 consumption by tenants of that building. (CAUSE-PA St. No. 1, p. 119-120.) Finally, he
21 identifies new conditions proposed by the Company, which will allow submetering to occur
22 where the master metered customer lives in subsidized or public housing, an assisted living
23 or rehabilitation facility, student housing, or where the Company determines that individually
24 metering tenants will not be beneficial. (CAUSE-PA St. No. 1, p. 120.)
25

1 **Q. Does Mr. Cicero raise any concerns regarding these proposals?**

2 A. Yes. He expresses concern regarding situations where submetering would facilitate the resale
3 of electric service to tenants, citing six consequences that he identifies as problematic for the
4 Company and/or its customers. (CAUSE-PA St. No. 1, p. 120.) He also is concerned that the
5 Company's proposals would restrict "submetering to situations where the master metered
6 units are designed to use the same amount of electricity or more than if the units were
7 individually metered by the Company." (CAUSE-PA St. No. 1, p. 120.)

8
9 **Q. Does Mr. Cicero recommend any revisions to the Company's Retail Tariff to address**
10 **these concerns?**

11 A. Yes. He recommends the following changes to Tariff Rule 5(E), noted in red, on page 121 of
12 his testimony.

13 E. REDISTRIBUTION OF SERVICE

14
15 (1) At the service locations covered hereunder connected after May 21, 1980,
16 each tenant shall be served, metered and billed individually by the Company
17 under the appropriate rate schedule except where the Company has permitted
18 master metering with resale in accordance with the provision of Tariff Rule
19 5(E)(2). Upon application to the Company, any owner (or their duly
20 authorized representative) of a new multi-tenancy commercial building may
21 seek an exception to Tariff Rule 5(E) by demonstrating that the installation
22 of individual electric meters at each separate unit within the building is
23 neither feasible nor practical from a financial, technical, engineering,
24 and/or any other valid reason. If the Company approves an exception to this
25 Rule, the master meter must be designed so that it will not ~~achieve any~~
26 ~~notable reduction in the consumption of electricity by the tenants in the~~
27 ~~building than if the tenant units had individual electric meters within the~~
28 ~~building with efficient heat controls.~~ result in a notable increase in
29 consumption but is designed to allow the master metered customer to either
30 maintain or reduce consumption.
31

(2) Company, at its discretion, may permit submetering for both existing and new service locations when the conditions are present:

(a) It is impractical for the Company to separately bill each tenant;

(b) Each tenant has control of the majority of their electric energy use;

(c) Customer is part of a US-HUD funded Housing, Assisted Living, Nursing Home Care Rehabilitation facilities, Student Housing – higher education; Federal/State/County/City/Municipal/Public Housing; and/or

(d) At the Company’s discretion, it is not beneficial for the Company to meter individual tenants.

Effective July 1, 2026, any locations that are permitted to submeter pursuant to Rule 5(E)(1) or (2)(c) shall not be permitted to resell their energy or re-bill residential tenants for submetered service. ~~Commercial / industrial tenants submetered may be not be billed more than according to non-residential Rate Schedules.~~

Q. Please respond to CAUSE-PA Witness Cicero’s concerns regarding submetering, and Tariff Rule 5(E). (CAUSE-PA St. No. 1, pp. 121-122.)

A. The Company agrees with the deletion and insertion proposed for Rule 5(E)(1), and will reflect this change in the compliance tariff to be filed after the Commission issues a final order in this proceeding. However, the Company does not agree with the proposed addition to Rule 5(E)(2), as PPL Electric is not privy to landlord-tenant lease agreements in order to enforce this provision.

Relatedly, Mr. Cicero recommended the following addition to Tariff Rule 5(E) (CAUSE-PA St. No. 1, p. 122), which is reflected below:

(4) Tenants who are served by a master meter retain all rights under 66 Pa. C.S. § 1521 et seq., the Discontinuance of Service to Leased Premises Act [DSPLA] regardless of whether the Landlord Ratepayer has sub-metered the location pursuant to the terms of this tariff. For Tenants who have sub-metered service, the amount that the Tenant will be required to pay to maintain service

1 to the entire premises will be based on the Tenant's sub-metered usage for the
2 30 days prior to the notice required by law.
3

4 The Company has no objection to this proposed revision.
5

6 **Q. Mr. Cicero also opposes the Company's limitation of liability language in its proposed**
7 **retail tariff and recommends that the Company adopt limitation of liability provisions**
8 **that are consistent with PECO Energy Company's ("PECO") tariff. (CAUSE-PA St.**
9 **No. 1, pp. 127-28.) Please respond.**

10 A. As part of updating its retail tariff, PPL Electric determined that its existing limitation of
11 liability provisions could benefit from an update. Currently, the Company's Commission-
12 approved tariff provides in Rule 4(F)(1), "The Company uses reasonable diligence to preserve
13 continuity of service, but in the event of interruption or curtailment of service, Company shall
14 not be subject to any liability, penalty or payment for or on account of any such interruption
15 or curtailment nor shall the application of the rate schedule to the regular billing period be
16 affected." Supp. No. 42 to Electric Pa. P.U.C. No. 201, Fourth Revised Page No. 8D. PPL
17 Electric has proposed to revise the limitation of liability provision in Rule 4 as follows:

18 In no event shall the Company be liable for incidental, indirect, special or
19 consequential damages, including loss of use or profit or loss of business. The liability
20 of the Company to customers or other persons for damages other than incidental,
21 indirect, special or consequential damages, including loss of use or profit or loss of
22 business shall in no event, unless caused by the willful and/or wanton misconduct of
23 the Company, exceed an amount in liquidated damages equivalent to the greater of
24 \$500 or two times the charge to the customer for the service affected during the period
25 in which the damages occurred. These limitations shall apply whether the claim is
26 pleaded in contract or in tort, including negligence and strict liability in tort.

27 (PPL Electric Exhibit GEO-1, p. 30.)

1 The proposed revision is intended to resolve ambiguity and uncertainty regarding the
2 Company's existing limitation of liability provision. Also, I am advised by counsel that the
3 enforceability of broad limitation of liability provisions in tariffs has been the subject of prior
4 litigation. *See, e.g., State Farm Fire & Cas. Co. v. PECO Energy Co.*, 54 A.3d 921, 929-31
5 (Pa. Super. 2012) ("*State Farm*") (holding that PECO's electric tariff, which limited the
6 amount of recovery to the "amount of \$500 or 'two times the charge to the customer for the
7 service affected during the period in which such interruption ... or any other failure of supply
8 in electricity occurs,' whichever is greater," does not disclaim strict liability). PPL Electric
9 seeks to revise its proposed limitation of liability provision to better withstand such scrutiny.
10 As such, the Company benchmarked its existing tariff against peer utilities in Pennsylvania.
11 In fact, the Company's proposed language matches the limitation of liability language in
12 Peoples Natural Gas Company's ("Peoples") Commission-approved retail gas tariff.¹

13 Furthermore, I disagree that the Company must adopt the language from PECO's
14 current tariff proposed by Mr. Cicero. The prior version of PECO's tariff, which was the
15 subject of the litigation in *State Farm*, prescribed a cap on liquidated damages of \$500 or two
16 times the charge to the customer for affected service, as noted previously. Further, that
17 amount, along with the other provisions proposed by PPL Electric, align with Peoples'

¹ See Supp. No. 2 to Gas – PA PUC No. 48, First Revised Page No. 25 (stating, in pertinent part, "In no event shall the Company be liable for incidental, indirect, special or consequential damages, including loss of use or profit or loss of business. The liability of the Company to customers or other persons for damages other than incidental, indirect, special or consequential damages, including loss of use or profit or loss of business shall in no event, unless caused by the willful and/or wanton misconduct of the Company, exceed an amount in liquidated damages equivalent to the greater of \$500 or two times the charge to the customer for the service affected during the period in which the damages occurred. These limitations shall apply whether the claim is pleaded in contract or in tort, including negligence and strict liability in tort.").

Commission-approved tariff. Thus, I maintain that PPL Electric's proposed revisions should be approved.

Q. Do you have any other adjustments to the proposed tariff revisions?

A. Yes, there was a section that was mistakenly revised in the Net Metering for Renewable Customer Generators section. The edit is in PPL Electric Exhibit GEO-1 on page 263 of 662:

Additional metering equipment for the purpose of qualifying alternative energy credits ~~generated owned~~ by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits (AECs) produced by a customer-generator ~~where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits.~~ The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

The Company is proposing to undo the revisions to return the text to the following:

Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

The Company commits to making this revision in a compliance filing after the final Commission order on its rate case.

1 **III. INTERCONNECTION PROCESS FOR NON-EXPORTING BEHIND THE METER**
2 **BATTERY ENERGY STORAGE SYSTEMS**

3 **Q. Do you believe that Convergent Witness Guerry fairly summarizes the interconnection**
4 **process for non-exporting behind the meter battery energy storage systems (“BTM**
5 **BESS”) (Convergent St. No. 1, pp. 3-4)?**

6 A. No. Specifically, she is incorrect that PPL Electric’s governing documents do not contain
7 clear or transparent interconnection rules applicable to these entities. The Company’s
8 response to discovery request Convergent I-10, and in particular Attachment 1, contains the
9 PPL Distribution Energy Storage Interconnection Policy and Guidance. This document
10 provides clear technical standards and expectations for an interconnection application for a
11 BTM BESS to the Company’s distribution system. A copy of the Company’s discovery
12 response and its Attachment 1 are attached to my rebuttal testimony as PPL Electric Exhibit
13 GEO-1R. Furthermore, I note that the Company maintains a unified position that neither
14 Transmission nor Distribution allows BESS to export power onto the system. Transmission
15 and Distribution each applies its own technical protection standards accordingly.

16
17 **Q. Please respond to Convergent Witness Guerry’s attempt to identify and summarize the**
18 **operational challenges perceived by Convergent regarding the Company’s approach to**
19 **non-exporting BTM BESS interconnections? (Convergent St. No. 1, p. 4.)**

20 A. Ms. Guerry errs in claiming that the Company’s approach to non-exporting BTM BESS is
21 unclear and that non-exporting BTM BESS should not be treated as a generation resource. It
22 is in the Company’s best interest to treat and classify BTM BESS as a generation source
23 because BESS units can be electrically coupled with characteristics that are nearly

1 indistinguishable from traditional generation resources in terms of electrical physics and their
2 interaction with the utility system. Furthermore, PPL Electric cannot rely on non-utility
3 owned equipment, mechanisms, or software to ensure adequate protection and the safe,
4 reliable operation of the electric grid. As an example, PPL Electric received Commission
5 approval under its Second DER Management Plan to use smart inverters' Remote On/Off
6 functionality to shut off DERs that fail to shut off on their own when there is an emergency
7 that would potentially place Company personnel, first responders, and the public at risk.
8 Opponents argued that DERs should be entrusted to shut off on their own in those situations.
9 However, when the safe and reliable operation of the electric distribution system is at risk,
10 PPL Electric cannot simply rely on non-utility owned equipment, mechanisms, or software.
11

12 **Q. Ms. Guerry also raises two concerns with the Company's current approach to the**
13 **interconnection of non-exporting BTM BESS, namely that: (1) PPL Electric "has not**
14 **established rules specifically applicable to BTM for this class of resource"; and (2) PPL**
15 **Electric applies rules "developed for generation resources" to this resource.**
16 **(Convergent St. No. 1, p. 5.) She then recommends that PPL Electric address its**
17 **interconnection rules for non-exporting BTM BESS in this rate case. (Id., pp. 5-6.)**
18 **Please respond.**

19 **A.** As an initial matter, I disagree with Ms. Guerry's concerns that the Company's existing
20 interconnection rules are unjust and unreasonable.

21 Moreover, shortly before Ms. Guerry submitted her direct testimony on December 22,
22 2025, the Commission adopted a Motion by Vice Chair Barrow on December 18, 2025, to

1 initiate a rulemaking proceeding at Docket No. M-2025-3059032 to modernize the
2 Commission's interconnection regulations. I believe Ms. Guerry's issues with the existing
3 interconnection rules are better addressed in that proceeding, as opposed to PPL Electric's
4 rate case. Indeed, while the Company complies with its Commission-approved tariff during
5 the interconnection process, the detailed interconnection procedures and processes are not
6 dictated by the Company's tariff and should be filed separately for them to have the necessary
7 flexibility to adapt to an ever-evolving DER market. Furthermore, any modifications to the
8 existing interconnection standards, procedures, and requirements would require extensive
9 review and cannot realistically be completed within the short timeframe of a base rate
10 proceeding, which already involves a number of other complex and unrelated issues.

11 Nevertheless, I note that PPL Electric remains committed to reviewing its existing
12 interconnection rules and standards to determine whether enhancements are warranted. This
13 review will focus on refining the specific provisions applicable to non-exporting BTM BESS
14 installations, with the objective of establishing clear, equitable, and cost-effective
15 requirements that uphold the safe and reliable operation of the electric grid.

16
17 **IV. PPL ELECTRIC'S MAXIMUM REGISTERED PEAK LOAD PROPOSAL**

18 **Q. Some of the other parties have opposed the Company's Maximum Registered Peak**
19 **Load ("MRPL") proposal, which would change how no-load customer-generators are**
20 **classified for purposes of the Company's default service rates. (See JSA St. Nos. 1 and**
21 **2; CGC St. No. 1; PDMP St. Nos. 1 and 2.) Among other things, they allege that approval**

1 **of the Company’s proposal would negatively impact solar development. (See, e.g., CGC**
2 **St. No. 1, pp. 22-23.) Are you familiar with the Company’s MRPL proposal?**

3 A. Yes.

5 **Q. Several of the other parties have indicated that they are surprised by the MRPL**
6 **proposal, and that it is changing the rules upon which they made investment decisions.**
7 **Did the Company receive inquiries from solar developers and customers after making**
8 **its rate case filing?**

9 A. Yes. The Company has received questions from many developers and customers, including
10 but not limited to: BlueWave Energy, Coast Energy, Coral Reef, Cultivate Power, CVE US
11 PA, Dimension Energy, Dynamic Energy, Prologis, Aspen Power, MHK Attorneys, Moore
12 Energy, New Leaf Energy, Pivot Energy, Scale Microgrids, Sigma Renewables, Solar
13 Landscape, Solar Renewable Energy, Solops/Virtue Power, Syncarpha Solar, TotalEnergies,
14 etc. In total, these developers currently have over 250 large DER applications² in the
15 Company’s interconnection queue.

17 **Q. What were the nature of these questions?**

18 A. Solar developers have been asking the Company about the proposed change to the definition
19 of MRPL in the new version of the Company’s Tariff, as well as the potential reclassification
20 of their applications from Rate Class GSC-1 to GSC-2. Many developers are also seeking

² For the purposes of this testimony, a “large DER application” is any interconnection application for a DER that is greater than or equal to 100 kW single-phase or 250 kW three-phase.

clarification on the proposed grandfathering provisions, specifically, where the cutoff would be, whether their projects would remain under GSC-1, and if so, for how long.

Q. Has the Company seen an increase in large DER application cancellations since the filing of PPL Electric's Rate Case?

A. No. PPL Electric has not seen a major increase in cancellations to existing or in-flight DER applications from these developers that coincides with the filing of the Rate Case. Businesses operating within the utility industry understand that rates and pricing inherently fluctuate over time and accept these risks. Moreover, there are a whole host of reasons why a developer may choose to cancel a project. For example, they could have issues with permitting, zoning, or financing issues that make the developer decide to cancel a project.

Q. In your experience in dealing with solar developers do you think they are surprised by the MRPL proposal?

A. No, the interconnections team frequently received questions prior to the submission of the Company's rate case about whether PPL Electric was considering changes to its tariff. The Company also received questions about potential impacts of proposed legislation on their projects. In my experience the large no-load customer-generators were aware of potential changes to the compensation structure for no load installations and decided to proceed with their applications.

Q. Has the Company considered other parties' grandfathering proposals?

1 A. Yes, but as explained in PPL Electric witness Castanaro's rebuttal testimony (PPL Electric
2 St. No. 15-R), their proposals should be rejected.

3
4 **Q. Could you please respond to CGC Witness Sharfman's claims regarding the**
5 **investments that CGC members have purportedly made to interconnect to the system**
6 **within PPL Electric's territory, and the costs of system upgrades (CGC St. No. 1, pp. 7-**
7 **8)?**

8 A. These upgrades were required solely due to the customer-generators' decision to interconnect,
9 with the potential, and often intention, to export power to the grid. These costs were not driven
10 by system-wide needs, but by the incremental requirements of accommodating their
11 generation facilities to ensure grid safety and reliability. Despite Mr. Sharfman's assertions,
12 no other customers benefit from the upgrades to interconnect customer-generators. Thus, it
13 would not be reasonable or appropriate for the Company to allocate these costs amongst
14 existing customers; they should instead be borne by the customer(s) causing these costs to be
15 incurred. Additionally, any unspent portions of these costs are refunded to customers if they
16 elect to cancel.

17
18 **Q. Is it relevant to PPL Electric's MRPL proposal that no-load customer-generators have**
19 **purportedly paid "millions of dollars to upgrade substations, feeders, protection**
20 **equipment, and related facilities in order to secure their position in the interconnection**
21 **queue," as alleged by CGC Witness Sharfman? (CGC St. No. 1, p. 26.)**

1 A. No, it is not relevant. The no-load customer generators initially establish their position in the
2 interconnection queue by submitting an application fee and the required documentation. Once
3 the applications are properly studied, they maintain their position in the queue by paying 25%
4 of the total estimated cost of the scoped reinforcements necessary to interconnect these
5 customers safely and reliably. This process ensures that PPL Electric does not burden non-
6 DER customers with these costs in the event an applicant cancels their application and fails
7 to reimburse the Company for accrued charges. Also, as noted previously, an unspent portion
8 of the 25% deposit would be refunded to the applicant if they decide to cancel their project.
9 Further, all DER customers, including no load customer-generators, will have their costs trued
10 up if the final actual costs to install the required system reinforcements differ from the initial
11 estimated costs.

12
13 **Q. CGC Witness Sharfman also alleges that customer-generators are “partners of PPL;
14 contributing both clean generation and customer-funded infrastructure investments
15 that support system reliability and advance the Commonwealth’s energy policy
16 objectives.” (CGC St. No. 1, p. 26.) Would you please respond?**

17 A. Clean energy policy objectives do not negate the need for proper classification and pricing to
18 reflect customer-generators’ actual impact on system planning and customers. To reiterate
19 what is stated above, these system reinforcements are only required to safely and reliably
20 interconnect these no-load generation customers to the grid. The customer-generators are not
21 contributing toward infrastructure investments that are needed to serve other customers.
22 Again, PPL Electric works with and will continue to work with customer-generators that seek

1 to interconnect to its system, but the Company will do so in a manner that maintains the safety
2 and reliability of its system.

3
4 **Q. Do you agree with JSA Witness Lucas's criticisms of the Company's position that the**
5 **no-load customer-generators cause stress on the distribution system, including his**
6 **arguments against wear and tear on PPL Electric's distribution facilities (such as**
7 **transformers), and his position that solar distributed generation should help reduce**
8 **wear and tear on distribution assets (JSA St. No. 1, pp. 6, 17, 22, 25-30)?**

9 A. No. PPL Electric maintains that distributed generation causes stress on the distribution system.
10 Wear and tear occurs regardless of the direction of power flow. Exported generation can
11 subject distribution equipment to thermal loading and voltage fluctuations similar to, and in
12 some cases more severe than, traditional load. For example, line transformers experience
13 accelerated aging when subjected to continuous loading above their transformer nameplate
14 capacity that can lead to overheating and subsequently lower life expectancy. Export from
15 generation facilities also can cause multiple peaks on the transformer and stress the
16 distribution system as a result. Also, voltage regulation devices, such as regulators and
17 capacitor banks, experience increased operation frequency due to distributed generation
18 variability. Solar generation output fluctuates with cloud cover and other environmental
19 factors, causing voltage swings on feeders. These swings trigger more frequent tap changes
20 and switching operations on regulators and capacitors, which shortens equipment life and
21 raises maintenance costs. As I previously discussed, PPL Electric charges customer-
22 generators one time for upgrades to protect the safety and reliability of the distribution system

1 at the time of interconnection. In the case of customer-generators with generation far in excess
2 of its load there will be little to no distribution revenue to cover the costs of the customer-
3 generators use of the distribution system.

4
5 **Q. Does JSA Witness Lucas’s assertion that, if a front-of-the-meter distributed generation**
6 **(“FTM DG”) customer causes any undue stress on the distribution grid, such customer**
7 **would have to pay for all electric system upgrades deemed necessary by PPL Electric to**
8 **address the fact that no-load customer-generators cause stress on the distribution**
9 **system (JSA St. No. 1, pp. 25, 32)?**

10 **A.** No. While no load customer-generators do pay for the upfront electric system upgrades
11 necessary to maintain the safety and reliability of the Company’s system, they do not pay for
12 the operation and maintenance costs associated with replacing this equipment at the end of its
13 life. Mr. Lucas’s claim also fails to account for the increased switching and/or tap movements
14 of voltage-regulating devices, which have a finite operational capacity, and may need to be
15 replaced earlier than anticipated due to higher penetration of DER customers on the
16 distribution system, as I explained above.

17 Furthermore, no-load customer-generators pay only for the reinforcements identified
18 at the time of their study. As system conditions evolve over time, such as variations in load
19 levels, voltage profiles, and reactive power, these interconnected customers may trigger the
20 need for additional system reinforcements. The Company will not recover the cost of these
21 subsequent upgrades from no-load DER customers, even though their interconnections can
22 create or exacerbate issues such as reverse power flow at the substation, high voltage, and

1 rapid voltage drop. When this occurs, PPL Electric is required to install the necessary
2 reinforcements, and the costs will be borne by non-DER customers.

3
4 **Q. PDMP Witness Harbach claims that the Company’s proposal will result in customer-**
5 **generators, like Schrack Farms, being classified as Rate GSC-2 customers, which will**
6 **reduce the compensation it receives from its excess generation and will cause**
7 **“immediate and devastating” financial harm to the farm and the farms of other**
8 **members of the PDMP. (PDMP St. No. 1, p. 1.) Please respond.**

9 A. PPL Electric will only classify a customer for Rate GSC-2 if they meet the MRPL criteria.
10 This evaluation must occur on a customer-by-customer basis with telemetered load and
11 generation data. Furthermore, as explained in PPL Electric witness Castanaro’s rebuttal
12 testimony (PPL Electric St. No. 15-R), customer-generators should not be paid for their excess
13 generation at an inflated Price to Compare (“PTC”) rate simply so that they can make a profit
14 off their investments. These payments to customer-generators are a real cost being borne by
15 Small C&I customers in their default service rates, and the economics of an individual
16 customer-generator operating in a competitive market should not control whether the
17 Company’s MRPL proposal is approved.

18
19 **Q. Do you believe that the Company is “watering down” the value that the Company pays**
20 **for the energy produced by the farm and the infrastructure paid for by the farm?**
21 **(PDMP St. No. 1, pp. 4-5.)**

1 A. No. PPL Electric compensates excess generation at PTC under the current net metering tariff.
2 This is a reasonable and compensatory rate, and I am advised by counsel that PPL Electric's
3 practice comports with the Alternative Energy Portfolio Standards ("AEPS") Act and the
4 Commission's regulations and that such arguments have been rejected by the Commission in
5 UGI Utilities, Inc. - Electric Division's ("UGI Electric") most recent Default Service Plan
6 ("DSP") proceeding and, even more recently, in Citizens' Electric Company of Lewisburg's
7 ("Citizens' Electric") 2025 Rate Case.

8
9 **Q. Please respond to PDMP Witness Harbach's discussion of previous interactions with**
10 **PPL Electric regarding the replacement of the generator earlier this year. (PDMP St.**
11 **No. 1, p. 6.)**

12 A. PPL Electric makes every effort to accommodate interconnection requests, despite the large
13 volume of applicants and constant communication requests. Long interconnection times are a
14 factor of customer requirements being met, material lead time, construction timelines, right-
15 of-way requests, and more. Third party electrical inspections are required for local authorities
16 having jurisdiction to ensure all NEC, municipal, and other requirements are met, over which
17 PPL Electric does not have jurisdiction.

18
19 **Q. Do you agree with Mr. Harbach's claim that PPL Electric pays less than the PTC for**
20 **the electricity that the farm's digester puts back onto the distribution system (PDMP St.**
21 **No. 1, p. 7)?**

1 A. No. PPL Electric compensates customers for excess generation at the current PTC. Further,
2 Mr. Harbach admitted in discovery that he misstated “price to compare” and that he intended
3 to say “full retail value.” (PPL Electric Exhibit GEO-2R [PDMP Answer to PPL to PDMP-
4 II-11].) As I explained previously, counsel has advised me that the Company’s net metering
5 compensation practices, including its use of the PTC to calculate the cash-out for customer-
6 generators’ banked excess generation, comply with the AEPS Act and Commission’s
7 regulations.

8
9 **Q. Do you have any comment on PMDP Witness Harbach’s claims about the grants**
10 **received by the farm for the digester, the revenues the farm receives from its digester,**
11 **the farm’s inability to be profitable even with the digesters’ revenue, and issues with**
12 **odor reduction and environmental stewardship? (PDMP St. No. 1, pp. 7-8.)**

13 A. PPL Electric supports positive environmental impact and state-wide initiatives. Additionally,
14 it supports compensating customers in accordance with the AEPS Act and the Commission’s
15 regulations but not at the expense of harming the Company’s customers. Furthermore, as I
16 stated previously, PPL Electric witness Castanaro explains in his rebuttal testimony (PPL
17 Electric St. No. 15-R) that customer-generators should not be paid for their excess generation
18 at an inflated PTC rate simply so that they can make a profit off their investments. The primary
19 concern in making the MRPL proposal in this rate case is to ensure proper rate design to treat
20 all customers equitably and fairly. There are more appropriate forums to address Mr.
21 Harbach’s environmental concerns outside of the Company’s rate case.

1 V. **CONCLUSION**

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

3 A. Yes, it does.

WITNESS: Gregory Olsen

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Convergent Energy and Power LP
Dated November 17, 2025
Docket No. R-2025-3057164

Convergent I-10 Does the PPL Tariff address all technical requirements associated with a customer installing and interconnecting Non-exporting Battery Storage? If not, please provide a list of the technical documentation and whether any of the documents have been reviewed by the Commission or Commission staff.

PPL Electric
Response In addition to the PPL Electric Tariff, the Company's Rules for Electric Meter & Service Installations ("REMSI") addresses the technical requirements associated with interconnecting to PPL Electric's system, including non-exporting battery storage as shown in Convergent I-10 Attachment 1. PPL Electric's REMSI was not required to be approved by the PUC but is generally subject to PUC jurisdiction.

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0	02/01/2023	808010	Energy Storage Interconnection Policy and Guidance Document Created		MAK	NP	KWG		
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SCALE – NONE									
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BY – MAK, JC			PPL ELECTRIC UTILITIES						
CHECKED – NP									
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INTERCONNECTION & TARIFF RULES			Kimberly Gauntner 02/01/2023 Interconnection & Tariff Rules - Supervisor		EU00565314	1 of 12	0		

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1 BACKGROUND AND PURPOSE

PPL Electric has developed guidelines and acceptable energy storage system (ESS) configurations to be installed in PPL Electric's service territory to ensure safe and reliable service for all distribution customers.

This document provides the guidelines for the interconnection of ESSs installed in various configurations on the distribution system:

- 1a) Provide standby (back-up power) during power outages
- 1b) Parallel operation with the utility without on-site generation
- 1c) Parallel operation with the utility in conjunction with on-site generation

This PPL Electric Energy Storage Interconnection Policy and Guidance Document will be modified as needed to reflect the Company's interconnection policies and standards, tariff rules as well as state and Pennsylvania's Public Utility Commission (PUC) regulations.

2 NET-METERING STATUS

At the time of the publication of this policy and guidance document, PPL Electric's Tariff and the Alternative Energy Portfolio Standards (AEPS) Act of 2004, as enforced by the Pennsylvania Public Utilities Commission (PUC), does not qualify ESSs for net-metering.

3 EXCLUSIONS

This document applies to energy storage interconnections in PPL Electric's service territory that operate within the jurisdiction of PPL Electric's tariff. This document does not apply to energy storage interconnections that are operating within a Wholesale Market Participation Agreement (WMPA) between PJM, PPL Electric, and the customer.

4 INTERCONNECTION REVIEWS

Customers must submit an interconnection application for their prospective generation and/or energy storage Distributed Energy Resource (DER). An interconnection application consists of an interconnection review to ensure system safety and reliability as well as compliance with technical and operational requirements. Customers that intend to install an ESS in parallel with the PPL Electric grid are required to sign an Interconnection Agreement (IA).

When an ESS is installed alongside a generation system within the same application, such as solar plus storage, they will be reviewed simultaneously. For inverter-based generation, the interconnection review will be based solely on the rated capacity of the inverter directly connected to the generation system, not the combined capacity of the inverter-based generation and the ESS. At the time of publication of this document, the storage nameplate capacity will not be considered during interconnection review as ESSs are ineligible for net-metering and are prohibited from exporting energy to the grid. The non-export operating mode is a requirement and settings shall be provided at the time of application for ESSs operating in parallel with the distribution system. Any subsequent changes to the ESS's operating mode shall be communicated to PPL Electric and is subject to utility approval.

New interconnection applications must be submitted to modify or retrofit existing ESSs.

5 PPL ELECTRIC ENERGY STORAGE CONFIGURATIONS

The following are the only Energy Storage System (ESS) configurations permitted by PPL Electric's Tariff:

- 1a) Standby (backup) ESS without Generation
- 1b) ESS Operating in Parallel without Generation
- 1c) ESS Operating in Parallel with Generation

An Interconnection Agreement (IA) is required for any ESSs that are interconnected with the utility grid. ESSs that have no electrical connection to a PPL Electric system do not require an interconnection agreement. Consult your local Authority Having Jurisdiction (AHJ) for more information.

Each configuration is further elaborated in the following sections. Illustrations of the various configurations are shown in Section 7. The customer may have additional features at their facility that are not reflected in the diagrams, but the distinguishing operational features of any ESS installed by a customer shall be consistent with one of the following configurations. The functionality required for each configuration may be controlled by the inverter or control system programming. All configurations require that the customer/contractor utilize all necessary equipment and control system settings to ensure that

the ESS does not export to the grid. Verifiable proof of equipment installation and control system settings are required to ensure compliance with non-export of the ESS to the grid¹.

5.1 STANDBY (BACKUP) ENERGY STORAGE AS PERMITTED BY NEC 702 (1A)

Energy storage systems installed in this configuration with the grid do not need an interconnection agreement. This configuration is intended to supply power, automatically or manually, to the customer's facility in the event of a loss of power from the utility. This configuration does not qualify for net-metering and exporting energy to the grid using the ESS is strictly prohibited. This configuration can be charged by on-site generation or from the utility but may only discharge power to the customer's facility when electrically isolated from the PPL Electric grid. This configuration is typically used to power critical load panel(s), normally powered from the main panel, which can instead be powered by the standby (backup) ESS when there is a loss of power from the utility.

This configuration requires that the customer/contractor install an automatic or manual open transition (break-before-make) switch. This device will ensure that the ESS is able to be charged while connected to the utility and can only be discharged when a loss of power from the utility is detected.

An automatic transition switch is usually preferred to enable the automatic operation of the ESS when a loss of power from the utility is detected. National Electric Code (NEC) Article 702 addresses the transition device requirements for optional standby (backup) systems which this configuration must comply with. Manual Interlock kits and closed transition (make-before-break) switches are prohibited from being used for standby ESS applications. [PPL EU approved open transition automatic switches](#) can be found on the REMSI website. If a switch that does not appear on this list is to be used, the customer/contractor must provide the switch's model specification sheet for review and approval when submitting the interconnection application. Manual open transition switches are approved for use by PPL EU; however, an approved list of models is not maintained.

If the conditions for this energy storage configuration are met, PPL Electric recommends the following:

- Provide PPL EU with a one-line diagram
- Provide PPL EU with Electrical Inspection Cut-in Card indicating approval

To ensure the safety and reliability of the distribution system, PPL EU reserves the right to conduct an inspection to verify compliance. PPL Electric reserves the right to verify non-export status of ESSs by any means available to the utility.

¹ Verifiable proof should be provided when the interconnection application is submitted for review and approval. Verifiable proof can be in the form of one-line diagrams, equipment specification sheets and inverter operating mode and settings.

5.2 ENERGY STORAGE OPERATING IN PARALLEL WITHOUT GENERATION (1B)

This configuration allows the ESS to operate in parallel with the utility as a demand side management (DSM) resource but does not allow the ESS to export energy to the grid. This configuration does not qualify for net-metering and exporting energy to the grid using the ESS is strictly prohibited. Subject to the Inadvertent provisions below, the customer must provide the control system settings as part of the interconnection application to ensure that the ESS does not export to the grid. This configuration maybe charged from the utility and discharged to power the customer's facility while operating in parallel with the utility.

This configuration requires that the customer/contractor utilize all necessary equipment and control system settings to ensure that the ESS does not export to the grid. All inverters and ESSs must be Institute of Electrical and Electronics Engineers (IEEE) 1547 and Underwriters Laboratory (UL) 1741 SA certified as applicable.

To ensure safe interruption of the ESS, an AC disconnect switch must be installed between the load side of the utility billing meter and the ESS inverter to facilitate the immediate isolation of the system from the electric grid during emergencies.

If the conditions for this energy storage configuration are met, the following items must be provided to PPL EU prior to operating the system:

- Verifiable proof of equipment or control system settings to prevent net metering ineligible export from ESSs
- Approved Electrical Inspection Cut-in Card
- Signed Interconnection Agreement and Certificate of Completion

To ensure the safety and reliability of the distribution system, PPL EU reserves the right to conduct an inspection to verify compliance. PPL Electric reserves the right to verify non-export status of ESSs by any means available to the utility.

5.3 ENERGY STORAGE OPERATING IN PARALLEL WITH GENERATION (1C)

This configuration allows the combined generation and ESSs to operate in parallel with the utility as a DSM resource but does not allow the ESS to export energy to the grid. This design provides for the following:

- Allows the ESS to be charged by either the utility or the generator
- Allows the ESS to be discharged while operating in parallel with the utility.
- Applies only to systems that combine both generation and energy storage.
 - Types of generation include standby generation (i.e., backup diesel), self-generation² and net-metered generation³ such as solar photovoltaic.

Energy exported from the ESS does not qualify for net-metering and exporting energy to the grid using the ESS is strictly prohibited. PPL EU requires the customer/contractor to utilize all necessary equipment and control system settings to ensure that the ESS does not export to the grid.

Subject to the Inadvertent Export provisions below, the customer must provide the control system settings as part of the interconnection review.

All inverters and ESSs must adhere to the most recent versions of IEEE 1547 and UL 1741 as applicable.

To ensure safe interruption of the ESS, an AC disconnect switch must be installed in between the load side utility meter and the DER/ESS inverter to facilitate the immediate isolation of the ESS and/or DER from the electric grid in case of emergencies.

If the conditions for this energy storage configuration are met, the following items must be provided to PPL EU prior to operating the system:

- Verifiable proof of equipment or control system settings to prevent net metering ineligible export from ESSs
- Approved Electrical Inspection Cut-in Card
- Signed Interconnection Agreement and Certificate of Completion

To ensure the safety and reliability of the distribution system, PPL Electric reserves the right to conduct an inspection to verify compliance at any time. PPL Electric reserves the right to verify non-export status of ESSs by any means available to the utility.

² Self-generation is generation supplying some or all of the customer's demand from onsite generation with no intent to export or to be compensated for export.

³ Net-metered generation is generation at the customer's facility that is permitted to export to the grid and to be compensated for that export energy. Net-metered generation includes renewable generation that has been approved for net-metering.

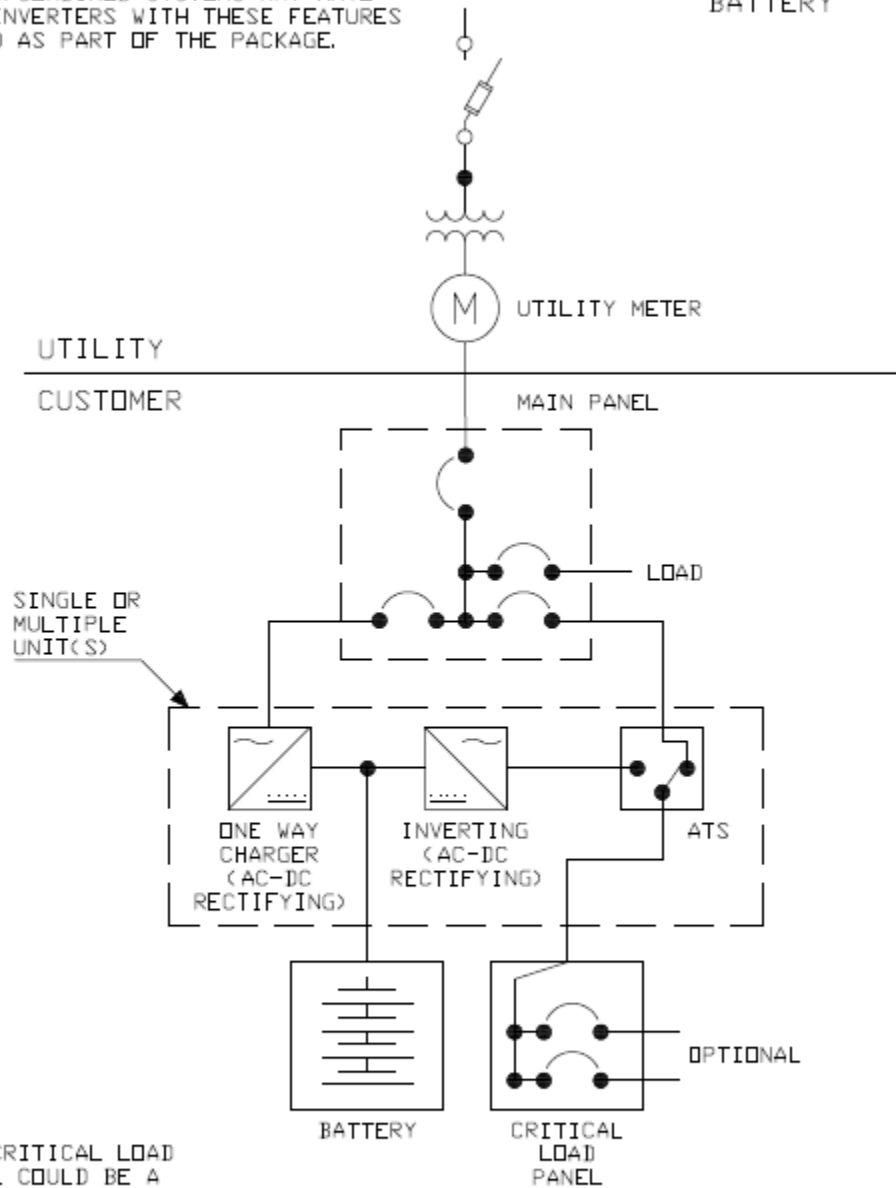
6 INADVERTENT EXPORT

The customer is responsible for ensuring that the ESS is inhibited from exporting energy to the grid. Inadvertent export is defined as the unauthorized export of real power to the grid from an export ineligible power source, such as an ESS, operating in parallel with the utility. The customer/contractor is required to use any combination of equipment and control system settings such as transfer relays, energy management systems or any other customer facility hardware or software to prevent the ESS from exporting to the grid.

7 DIAGRAMS

FIGURE ILLUSTRATES REPRESENTATIVE ENERGY STORAGE CONFIGURATIONS. PACKAGED/COMBINED SYSTEMS MAY HAVE HYBRID INVERTERS WITH THESE FEATURES PROVIDED AS PART OF THE PACKAGE.

#1A
STANDBY
BATTERY

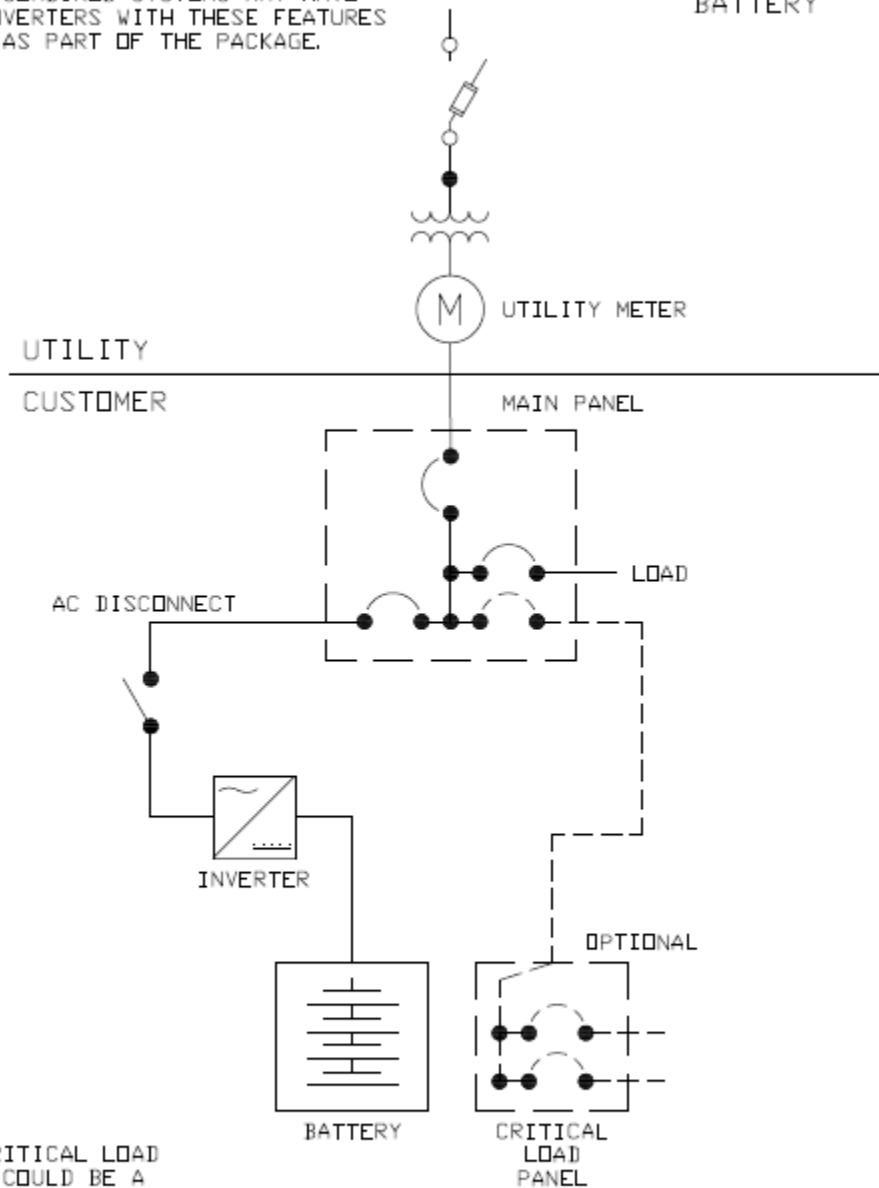


NOTES:

1. THE CRITICAL LOAD PANEL COULD BE A SEPARATE LOAD PANEL AS SHOWN IN THE DIAGRAM OR COULD BE THE ENTIRE MAIN PANEL
2. BATTERY NOT ALLOWED TO PARALLEL WITH OR EXPORT TO GRID

FIGURE ILLUSTRATES REPRESENTATIVE
ENERGY STORAGE CONFIGURATIONS.
PACKAGED/COMBINED SYSTEMS MAY HAVE
HYBRID INVERTERS WITH THESE FEATURES
PROVIDED AS PART OF THE PACKAGE.

#1B
PARALLEL
BATTERY

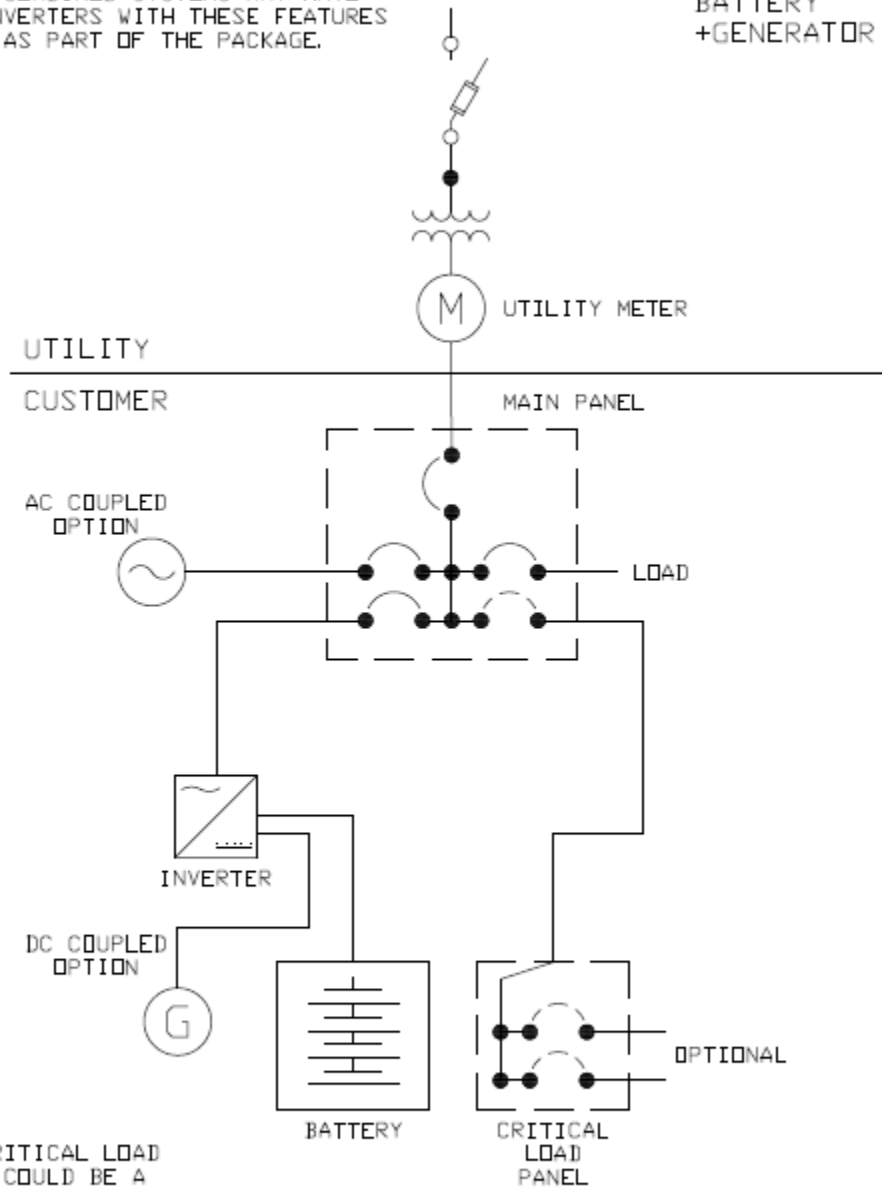


NOTES:

1. THE CRITICAL LOAD PANEL COULD BE A SEPARATE LOAD PANEL AS SHOWN IN THE DIAGRAM OR COULD BE THE ENTIRE MAIN PANEL
2. BATTERY NOT ALLOWED TO PARALLEL WITH OR EXPORT TO GRID

FIGURE ILLUSTRATES REPRESENTATIVE
ENERGY STORAGE CONFIGURATIONS.
PACKAGED/COMBINED SYSTEMS MAY HAVE
HYBRID INVERTERS WITH THESE FEATURES
PROVIDED AS PART OF THE PACKAGE.

#1C
PARALLEL
BATTERY
+GENERATOR



NOTES:

1. THE CRITICAL LOAD PANEL COULD BE A SEPARATE LOAD PANEL AS SHOWN IN THE DIAGRAM OR COULD BE THE ENTIRE MAIN PANEL
2. BATTERY NOT ALLOWED TO PARALLEL WITH OR EXPORT TO GRID

8 APPENDIX

8.1 ABBREVIATIONS

The following defined acronyms and abbreviations are used in this document:

AHJ	Authority Having Jurisdiction
DER	Distributed Energy Resource
DSM	Demand-side Management
EDC	Electric Distribution Company
ESS	Energy Storage System
IEEE	Institute of Electrical and Electronics Engineers
IA	Interconnection Agreement
NEC	National Electric Code
PA PUC	Pennsylvania Public Utility Commission
PPL EU	PPL Electric Utilities
PUC	Public Utility Commission
REMSI	Rules for Electric Meter and Service Installations
TOU	Time-of-Use
UL	Underwriters Laboratory
WMPA	Wholesale Market Participation Agreement

9 REVISION HISTORY

Revision 0 01/01/2022	Initial Procedure Release
Prepared by:	Mohamad A. Kanbari
	Senior Engineer, Distribution Interconnection & Tariff Rules
Reviewed by:	Niall Pascall
	Senior Engineer, Distribution Interconnection & Tariff Rules
	Mark Musheno
	Senior Engineer, Distribution Standards
Approved by:	Kimberly Gauntner
	Supervising Engineer, Distribution Interconnection & Tariff Rules
	Christopher Bash
	Supervising Engineer, Distribution Standards

**RESPONSES OF
THE PROFESSIONAL DAIRY MANAGERS OF PENNSYLVANIA
TO INTERROGATORIES AND REQUESTS FOR
PRODUCTION OF DOCUMENTS
TO PPL ELECTRIC UTILITIES CORPORATION, SET II**

DOCKET NO. R-2025-3057164

11. Reference PDMP Statement No. 1, p. 7. Please explain in detail how PPL Electric pays Schrack Farms “less than the price to compare for the electricity that [it] put[s] onto the distribution system.” Please also provide all documents relied upon by Mr. Harbach in reaching that conclusion and in responding to this discovery request.

RESPONSE:

The use of “price to compare” was an error that will be corrected. The testimony should have said “full retail value” instead.

Provided By: James Harbach

Date: January 16, 2026

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
ANDREW CASTANARO
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

HIGHLY CONFIDENTIAL VERSION

**Topics: Maximum Registered Peak Load
 Value of EDI Transaction Information for Default Supply and Capacity
 Allocations**

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Andrew Castanaro. My business address is 827 Hausman Road, Allentown,
4 Pennsylvania 18104.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed by PPL Services Corporation (“PPL Services”), an affiliate of PPL Electric
8 Utilities Corporation (“PPL Electric” or the “Company”) that provides services to PPL
9 Electric, as the Energy Procurement Manager.

10
11 **Q. Have you previously filed testimony in this matter?**

12 A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric
13 Statement No. 15.

14
15 **Q. What is the purpose of your rebuttal testimony?**

16 A. The purpose of my rebuttal testimony is to respond to the direct testimony of Office of
17 Consumer Advocate (“OCA”) Witness Zach Teti (OCA St. 6), Office of Small Business
18 Advocate (“OSBA”) Witness Mark Ewen (OSBA St. No. 1), Coalition for Affordable Utility
19 Services and Energy Efficiency in Pennsylvania (“CAUSE-PA”) Witness Patrick Cicero
20 (CAUSE-PA St. No. 1), Customer-Generator Coalition (“CGC”) Witness Guy Sharfman
21 (CGC St. No. 1), Joint Solar Advocates (“JSA”) Witnesses Kevin Lucas (JSA St. No. 1) and
22 Justin Barnes (JSA St. No. 2), Professional Dairy Managers of Pennsylvania (“PDMP”)

1 Witnesses James Harbach (PDMP St. No. 1) and Timothy Rensch (PDMP St. No. 2), and
2 Walmart Inc. (“Walmart”) Witness Matthew T. Lyon (Walmart St. No. 1), concerning the
3 Company’s Maximum Registered Peak Load (“MRPL”) proposal, which would assign
4 default service customers on the Generation Supply Charge (“GSC”) to Rate GSC-1 and Rate
5 GSC-2 based on their MRPL, as defined by the Company’s proposed retail tariff submitted in
6 this proceeding. I also will respond to an allegation by Retail Energy Supply Association
7 (“RESA”) witness Frank Lacey (RESA St. No. 1) about the value of Electronic Data
8 Interchange (“EDI”) on default supply costs and capacity allocations.

9
10 **Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?**

11 A. Yes. Attached to my rebuttal testimony are PPL Electric Exhibits AC-1R and AC-2R as well
12 as PPL Electric Exhibits AC-3R and 4R (HIGHLY CONFIDENTIAL).

13
14 **II. MAXIMUM REGISTERED PEAK LOAD**

15 **Q. Would you please summarize the parties’ stances on the Company’s MRPL proposal?**

16 A. In this proceeding, PPL Electric’s proposal has received support from the OCA, OSBA, and
17 CAUSE-PA. (See OCA St. 6, p. 3; OSBA St. No. 1, pp. 4, 13-15; CAUSE-PA St. No. 1, pp.
18 113-15.) Meanwhile, CGC, JSA, PDMP, and Walmart have expressed opposition to the
19 Company’s proposal. (CGC St. No. 1, pp. 5-30; JSA St. No. 1, pp. 4-49; JSA St. No. 2, pp.
20 4-46; PDMP St. No. 1, pp. 1-10; PDMP St. No. 2, pp. 3-8; Walmart St. No. 1, pp. 19-21.) I
21 note that CGC and JSA offer alternative modifications to the Company’s proposal as well.
22 (CGC St. No. 1, pp. 29-30; JSA St. No. 2, pp. 37-46.)

1
2 **Q. Could you please summarize OCA witness Teti's support for the Company's proposal?**

3 A. Mr. Teti believes that the MRPL will make the Company's default service procurement more
4 efficient by reducing uncertainty around volumetric procurement and avoid shifting risk
5 included in supply contract premiums. He further asserts that approval of the proposal would
6 create fairness across customers and customer classes in which compensation for customer
7 generators would not "corrupt the efficiency of the procurement process." (OCA St. 6, pp. 3-
8 4.)

9
10 **Q. Do you agree with Mr. Teti that the MRPL proposal will mitigate the need for risk**
11 **premiums in default service provider contracts to account for switching risk and**
12 **volumetric risk (OCA St. 6, pp. 10-11)?**

13 A. I agree that the MRPL will temper risk premiums for switching and volumetric risk, but it will
14 not completely eliminate them. There will still be uncertainty related to these factors, given
15 the ability of all customers to leave and return to default service.

16
17 **Q. Mr. Teti also states that he "would like to better understand the process by which**
18 **capacity costs and compensation to customer-generators are recovered by PPL**
19 **customers." (OCA St. 6, pp. 12-13.) He recommends that the Company provide clearer**
20 **explanation of: (1) how load reduction affects PJM Interconnection LLC ("PJM") costs;**
21 **(2) how customer-generators are compensated at retail rates made up of wholesale**
22 **components; and (3) the option for customer-generators to participate directly in the**

1 **wholesale market instead of the retail market. (OCA St. 6, p. 4.) Could you please**
2 **respond?**

3 A. Yes, and I will respond to each of Mr. Teti's questions below:

4 1. Load reduction and PJM costs – It is true that distributed generation can reduce
5 peak load. This would have the effect of lessening the amount of energy needed to be
6 procured under default service contracts and reduce PJM capacity obligations. Capacity and
7 ancillary costs are determined at the wholesale level and allocated to load-serving entities.
8 The Company is not disputing that customer-generators can reduce the amount of energy and
9 capacity to be procured for default service. This is why customer-generators are compensated
10 through load offsets and annual cash outs. The Company's proposal is not about the value
11 customer-generators add to the system, but rather the appropriate classification for providing
12 default service to these customers.

13 2. Retail rate components – Default service rates reflect bundled wholesale
14 procurement costs for energy, capacity, and ancillary services. When bundled, these costs
15 represent the retail rate charged to customers who are taking default service. Customer-
16 generators are compensated at the full retail value for their excess generation when the
17 Company uses the bundled default service rate (i.e., the Price to Compare or PTC) to calculate
18 the amount of the excess generation payout.

19 3. Direct wholesale participation – Customer-generators have a variety of
20 avenues to sell their generation. These customer-generators are able to enter into a Wholesale
21 Market Participation Agreement ("WMPA") with PJM to sell their generation to the market.
22 The WMPA would also allow these customer-generators to enter into bilateral power

1 purchase agreements (“PPAs”) at a mutually negotiated rate. These wholesale options are in
2 addition to customer-generators shopping for generation supply with an Electric Generation
3 Supplier (“EGS”) to potentially acquire a better rate for their excess generation than what the
4 PTC would provide.

5
6 **Q. Mr. Teti further states that the Company’s MRPL proposal will “not substantially”**
7 **impact residential customers with distributed energy resources (“DERs”). (OCA St. 6,**
8 **p. 13.) Do you agree?**

9 A. To clarify, no residential customers would be affected because residential customer-
10 generators’ alternative energy systems cannot have a nameplate capacity greater than 50 kW
11 and would therefore not reach the threshold established for reclassification.

12
13 **Q. Could you please summarize OSBA witness Ewen’s support for PPL Electric’s MRPL**
14 **proposal?**

15 A. Mr. Ewen agrees that the current classification of Small C&I default service customers are
16 disproportionately subsidizing large customer-generators that should be classified as
17 merchant generators in the Large C&I customer class. The current classification is causing
18 the GSC-1 default service customers to incur a higher cost burden to pay for the net metering
19 excess generation cashouts of minimal load customers.

20

1 **Q. Please summarize CAUSE-PA witness Cicero’s support for the Company’s MRPL**
2 **proposal?**

3 A. Mr. Cicero expresses concerns about affordability, particularly to multifamily, subsidized
4 housing providers to low-income households, as a result of excess compensation to merchant
5 generators. In addition, he states concern for potential impacts being spread to residential
6 customers if more customer generators come online.

7
8 **Q. Why do you think the support of OCA, OSBA, and CAUSE-PA is important when**
9 **evaluating the Company’s proposal?**

10 A. The support of these organizations is critical because they represent the interests of residential,
11 small commercial, and low-income customers. These are the groups that are most affected by
12 changes in default service and the subsidization created by current net metering cashout
13 practices. It is important to note that PPL Electric does not earn a profit in procuring electric
14 generation supply to serve default service customers. The Company’s interest in proposing
15 the MRPL is to ensure fair and equitable rate design to protect Small C&I customers from
16 adverse pricing effects due to the cash-outs for the excess generation of no-load customer-
17 generators. The Company’s proposal demonstrates its commitment to fairness, affordability,
18 and cost causation principles, intending to limit the burden placed upon default service
19 customers by unintended cost shifts.

20

1 **Q. What is the cost of procuring the default service supply to serve customers under Rate**
2 **GSC-1 as opposed to the costs of paying no-load customer-generators year-end cash-**
3 **outs for their excess generation?**

4 A. PPL Electric purchases energy, capacity, transmission, ancillary services, transmission and
5 distribution losses, congestion management costs, Alternative Energy Credits (“AECs”), and
6 other services or products that are required to supply default service customers through a series
7 of full-requirements, load following contracts at wholesale market rates. These costs are
8 recovered by the Company through the GSC-1 charged to Residential and Small C&I default
9 service customers. The GSC-1 is a reconcilable rider mechanism as described in Section
10 1307(e) of the Public Utility Code. See 66 Pa. C.S. § 1307(e). Separately, PPL Electric
11 compensates customer-generators participating in net metering consistent with the AEPS Act
12 and the Commission’s regulations. As such, every kWh of electricity produced by a
13 customer-generator’s system offsets one kWh of electricity used by that customer-generator
14 during the billing period. Any excess kWh produced by the customer-generator is banked
15 and applied to future billing periods. At the end of the PJM Planning Year (i.e., May 31 in a
16 given year), the Company cashes out the banked kWh at the PTC. For no-load customer-
17 generators, they have little to no load independent of the alternative energy system to offset
18 their generation. Therefore, they bank nearly all the kWh produced by their systems, and the
19 no-load customer-generators in the Small C&I customer class have their banked generation
20 paid out at the Small C&I PTC rate. Critically, that PTC rate is significantly higher than the
21 wholesale market prices that these merchant generators would otherwise receive for their
22 generation.

1
2 **Q. So, at a dollar-per-kilowatt level, is it more expensive for PPL Electric to pay for those**
3 **year-end cash-outs than it is to procure default service supply?**

4 A. Yes, undoubtedly.
5

6 **Q. Why is that?**

7 A. The Small C&I PTC at which year-end cashouts are being paid to SC&I customer generators
8 with excess generation is significantly higher than the wholesale market prices for default
9 service supply procurement. This is because the Small C&I PTC includes costs in addition to
10 the cost of generation supply, including administrative costs, net metering expenses, and an
11 amount associated with the reconciliation of over/under recovered costs. Put simply, 1 MW
12 of net-metered generation at the bundled PTC rate is always going to be more expensive than
13 1 MW of generation acquired from the Company's load following contracts which were
14 obtained through a competitive auction. This is clearly illustrated in PPL Electric Exhibit AC-
15 2R, which shows the calculation of the PTC by line item. Procurement costs for Small C&I
16 are included on page 5, lines 1-5. Also, page 5, lines 6 through 14 include the additional costs
17 included in the PTC for which these customers are compensated.
18

19 **Q. From your perspective, what are the goals of PPL Electric and the supporters of its**
20 **MRPL proposal compared to the goals of the opponents to the proposal?**

21 A. PPL Electric and its supporters are advocating for reforms that protect non-customer
22 generators from no-load customer-generator customers being misclassified and ensure cost

1 fairness for all customers. The current structure allows large merchant generators to receive
2 compensation for excess generation and is creating an inequitable cost burden shift for Small
3 C&I default service customers that subsidize these generators. PPL Electric's proposal seeks
4 to reclassify these merchant generators based on their peak demand or export peak, aligning
5 these customers with the appropriate rate class based on their impact to the system, costs to
6 serve load, and reducing unnecessary subsidies. This approach ensures that customer-
7 generators are grouped with other similarly situated customers for the purpose of receiving
8 default service.

9 Opponents, on the other hand, aim to maintain the status quo because it allows them
10 to continue profiting from an inflated PTC. Their position prioritizes preserving high PTC
11 levels to sustain merchant generator profitability, rather than focusing on least-cost, reliable
12 service for all customers. This stance conflicts with the Commission's statutory responsibility
13 to ensure affordability and reliability, not to guarantee profitability for merchant generators.
14 As noted in Mr. Cicero's testimony, net metering was never intended to serve as a mechanism
15 for large-scale merchant generation to exploit retail pricing constructs and maximize their
16 profits. The reforms proposed by PPL Electric are designed to restore the original purpose of
17 net metering—supporting customer-owned generation—while limiting cost shifts that harm
18 other ratepayers.

19
20 **Q. Other parties' witnesses have questioned the lawfulness of PPL Electric's MRPL**
21 **proposal, arguing, among other things, that the proposal conflicts with the Alternative**
22 **Energy Portfolio Standards ("AEPS") Act of 2004. Could you please respond?**

1 A. I am advised by counsel that nothing prevents PPL Electric from appropriately classifying
2 customers for the purpose of providing default service and that the Commission agrees. To
3 the contrary, the Company's proposal comports with PPL Electric's legal obligations,
4 especially its duty under the Public Utility Code to procure default service supply that is
5 designed to ensure adequate and reliable service to customers at the least cost to those
6 customers over time. See 66 Pa. C.S. § 2807(e)(3.4). In fact, the Commission approved a
7 substantially similar proposal in UGI Utilities, Inc. - Electric Division's ("UGI Electric") most
8 recent Default Service Plan ("DSP") proceeding that is now on appeal before the
9 Commonwealth Court of Pennsylvania, and even more recently approved a similar proposal
10 by Citizens' Electric Company of Lewisburg ("Citizens' Electric") in its 2025 Rate Case on
11 January 15, 2026. In both of those decisions, the Commission rejected solar developers' legal
12 arguments, including their claims that the companies' proposals violated the AEPS Act. For
13 these reasons, and as will be further explained in PPL Electric's briefs, the Company's MRPL
14 proposal not only complies with the law but is required for the Company to meet its statutory
15 obligation to provide adequate and reliable default service to customers at the least cost over
16 time.

17
18 **Q. Multiple parties in this case and individuals who testified at the public input hearings**
19 **have raised concerns about the affordability of electric bills. How will the Company's**
20 **MPRL proposal help mitigate the total bill impacts on customers?**

21 A. The Company's proposal directly addresses affordability concerns by ensuring that costs are
22 allocated fairly and transparently. As I noted in my direct testimony, PPL Electric projects

1 that the annual cash-outs for the Small C&I customer class will increase from approximately
2 \$11 million as of March 31, 2025, to between \$60 million and \$300 million by 2029. Those
3 increased expenses will drive up the PTC paid by all other Small C&I customers by an
4 estimated \$0.01806 per kWh to \$0.0836 per kWh, respectively. Based on the average
5 monthly usage for a Small C&I customer, those incremental increases in the PTC would
6 equate to increases in their average monthly bills between \$29.81 to as high as \$174.01,
7 respectively. By implementing objective classification criteria and reclassifying these
8 customers to the Large C&I customer class, pursuant to the MRPL, the Commission can help
9 ensure that Small C&I customers' bills remain more affordable by approving the MRPL
10 proposal.

11
12 **Q. Has CGC produced any information in discovery that reinforces the Company's need**
13 **to implement its MRPL proposal, including the affordability concerns you have**
14 **identified?**

15 A. Yes. PPL Electric propounded discovery on CGC asking its members for information about
16 the revenues they project to receive for each of their no-load generating facilities if PPL
17 Electric's MRPL proposal were denied, as well as the per kWh PTC rate they would need to
18 be profitable. Those responses reinforce PPL Electric's concerns and further support the need
19 to implement the Company's proposal.

20 Indeed, attached to my rebuttal testimony are PPL Electric Exhibits AC-3R (HIGHLY
21 CONFIDENTIAL) and AC-4R (HIGHLY CONFIDENTIAL). The former is a table
22 summarizing the data provided by CGC in response to PPL Electric's discovery requests on

1 these points, and the latter contains copies of CGC's actual discovery responses that were
2 used to complete the table. Based on those exhibits, I note the following.

3 **[BEGIN HIGHLY CONFIDENTIAL]** First, 9 of the CGC members cannot state
4 quantitatively how the MRPL proposal will impact their projects from a revenue standpoint.
5 6 of them have no projections for the revenues their projects would generate with or without
6 the MRPL proposal. 3 of them provided revenue data for a scenario where the MRPL
7 proposal is denied by the Commission but have no such data if the proposal is approved. Only
8 6 of the 15 companies provided both projections.

9 Second, for the 6 companies that did provide both revenue projections, the estimated
10 impacts varied significantly. On the low end, Radial Power projected that its revenues would
11 decrease by 14.77%, while on the high end, Aspen Power estimated that its revenues would
12 decrease by 57.18%. As such, there appears to be great inconsistency between the CGC
13 members on how to project the revenue impact from the Company's MRPL proposal.

14 Third, only 6 of the CGC members provided the per-kWh PTC rate their systems
15 would need to be profitable. Again, those rates varied, with the lowest being \$0.12000 per
16 kWh, and the two highest being \$0.17920 per kWh and \$0.19560 per kWh. Notably, the
17 current PTC rate for Small C&I customers is \$0.12681 per kWh. **[END HIGHLY**
18 **CONFIDENTIAL]**

19 Furthermore, as noted previously, parties and members of the public have raised
20 affordability concerns about electric rates repeatedly in this proceeding. As seen in PPL
21 Electric Exhibit AC-2R, the Company's current Small C&I PTC is \$0.12681 per kWh, which
22 is at historically high rates. PPL Electric earns no profit on its provision of default service

1 and complies with its default supply procurement plan to ensure the least cost reliable and
2 adequate supply service is provided to customers.

3 Conversely, the profits of CGC members and similarly-situated customer-generators
4 are tied to the Small C&I PTC rate, as that rate determines their year-end cash-out
5 compensation for excess generation. Therefore, they have no financial incentive to support
6 measures that could mitigate increases in the PTC. Rather, they have every financial incentive
7 to make the PTC increase as much as possible. **[BEGIN HIGHLY CONFIDENTIAL]** In
8 fact, CGC members appear to be banking on such rates increasing to unprecedented levels.
9 For example, two of the CGC members stated that they need a PTC rate of \$0.17920 per kWh
10 or \$0.19560 per kWh, respectively, for their systems to be profitable. Moreover, Aspen Power
11 revenue projections use PTC rates of approximately \$0.17 cents per kWh to calculate the
12 estimated \$4.14 million revenues its projects would receive in May 2027. **[END HIGHLY**
13 **CONFIDENTIAL]** These projects were risky investments, and PPL Electric's ratepayers
14 should not be forced to pay increased default service rates to ensure that no-load customer-
15 generators earn a profit on those investments. Thus, the Commission should approve PPL
16 Electric's MRPL proposal without modification.

17
18 **Q. CGC witness Sharfman alleges that "tariff structure that governs solar crediting is a**
19 **key factor that drives solar development in a market," that PPL Electric's "proposed**
20 **tariff changes effectively renege on the solar crediting structure that drove solar**
21 **expansion in the Company's service area," and "the proposed changes will harm many**
22 **GSC-1 customers by reclassifying them as GSC-2 customers, thereby greatly lowering**

1 **the revenue they currently receive for excess solar generation.” (CGC St. No. 1, pp. 5-**
2 **6.) Please respond.**

3 A. PPL Electric is required to provide least-cost, reliable electricity to non-shopping customers
4 in its service territory. *See* 66 Pa. C.S. § 2807(e)(3.2)-(3.4). It is not the Company’s
5 responsibility to ensure profits for customers through excess generation revenue. Furthermore,
6 the Company is not changing its solar crediting structure. Customer-generators will still have
7 their on-site load offset by their generation, and any excess generation will be paid out at the
8 end of the year using the applicable PTC for the customer. I am advised by counsel that
9 nothing prevents PPL Electric from appropriately classifying customers for the purpose of
10 providing default service and that the Commission agrees. In fact, as I noted previously, the
11 Commission approved a substantially similar proposal in UGI Electric’s most recent DSP
12 proceeding that is now on appeal before the Commonwealth Court of Pennsylvania, and even
13 more recently approved a similar proposal by Citizens’ Electric in its 2025 Rate Case.

14
15 **Q. Mr. Sharfman also asserts that the “reclassification of GSC-1 customers to GSC-2**
16 **would also expose these customers to a highly volatile and unpredictable wholesale**
17 **electricity market,” and because these customers “likely lack the tools to analyze and**
18 **mitigate the risks associated with the wholesale market[,] they may be harmed as a**
19 **result.” (CGC St. No. 1, p. 6; see *id.*, pp. 11-12.) Please respond.**

20 A. Exposure to price volatility is an inherent aspect of participating in any competitive market.
21 Additionally, in the Company’s experience, no load customer-generators are sophisticated
22 well-funded corporate entities. Their involvement in this case proves that they should have

1 the tools to analyze and evaluate risk. The arguments presented are around price sensitivity
2 for the viability of future projects, which is exactly the analysis that Mr. Sharfman claims that
3 these entities are too unsophisticated to perform.

4 Further, the PTC can also be volatile and can change dramatically over the expected
5 life of the no load customer-generator projects. For example, the Small C&I PTC increased
6 from 7.541 cents/kWh for the period 6/1/2021-11/30/2021 to 10.285 cents/kWh for the period
7 12/1/2021-12/31/2021, an increase of almost 40%. See PPL Electric Exhibit AC-1R for the
8 historical PTCs. If you accept the customer-generator parties' arguments that they need to be
9 compensated at current PTC levels to be financially viable, then if the PTC were to fall to
10 2021 levels, many of these projects would be in financial distress anyway. These customer-
11 generators have already accepted the risk of PTC fluctuations and decided to proceed despite
12 this risk.

13 Finally, no load customer-generators have other options than the Company's PTC.
14 What is at issue in this case is how these customers are classified for the purposes of default
15 service. There is nothing preventing no-load customer-generators from entering into
16 agreements with competitive suppliers to obtain compensation that is acceptable to them.

17
18 **Q. Do you agree with Mr. Sharfman that the Company's "proposal could materially hinder**
19 **solar development in PPL's service area since planned GSC-1 solar installs may be**
20 **canceled if the array is no longer economically viable under GSC-2" and that those**
21 **developers may focus on other utilities' service territories instead (CGC St. No. 1, p. 6.)?**

1 A. No, the proposal may alter the economics of no-load customer-generator projects, but it will
2 not have a material impact on overall solar installations. Customers remaining in the GSC-1
3 class will be evaluating economics under the same conditions as they currently do. As
4 mentioned previously, there is also no requirement that these customers take default service,
5 and they are free to shop if they do not think GSC-2 is appropriately compensating them for
6 their excess generation. In addition to the retail net-metering compensation model, these
7 customers can also sell their generation through the PJM markets.

8
9 **Q. Mr. Sharfman also alleges that the Company's proposal artificially inflates the MRPL**
10 **by bifurcating the MRPL derivation from the PJM ICAP and incorporating the**
11 **customer-generator's nameplate capacity. (CGC St. No. 1, pp. 14-15.) Do you agree?**

12 A. No, I do not agree with Mr. Sharfman's claim. The MRPL calculation is not intended to
13 identify or assign PJM capacity obligations; rather, it is solely used to determine the
14 appropriate default service rate class for customer-generators. PJM ICAP values serve a
15 different purpose related to wholesale capacity obligations, which are not relevant to retail
16 rate classification. Including nameplate capacity in the MRPL derivation ensures that
17 customers with significant generation capability are classified correctly for pricing purposes,
18 reflecting their potential impact on procurement and settlement processes.

19
20 **Q. Mr. Sharfman contends that the Company's filings confirm that DERs reduce, rather**
21 **than increase, customer demand and system load and argues that a resource that**
22 **"reduces net load, improves demand forecasting, and mitigates load masking cannot, as**

1 **a matter of sound electric system analytics or cost-causation principles, be**
2 **recharacterized as incremental customer demand.” (CGC St. No. 1, p. 15.) Please**
3 **respond.**

4 A. The Company’s focus is on the proper classification of customers, not on redefining system
5 load or customer demand metrics. The purpose of my testimony is to ensure accurate
6 categorization of customers within customer classes, independent of any demand forecasting
7 considerations. Furthermore, to the extent that Mr. Sharfman is contending that customer-
8 generators should be paid a premium for these alleged benefits, the PTC that is used to pay
9 them today and the PTC that will be paid under PPL Electric’s MRPL proposal is a premium,
10 given that it is higher than the wholesale rate that they otherwise would be paid if net metering
11 did not exist.

12
13 **Q. Is Mr. Sharfman correct that under PPL Electric’s proposal, “many GSC-1 customer-**
14 **generators would be reclassified as GSC-2” (CGC St. No. 1, p. 16)?**

15 A. No, of the approximately 1,250 commercial customer-generator installations on the system as
16 of January 5, 2026, only 18 would be reclassified from GSC-1 to GSC-2 if the Company’s
17 MRPL proposal is approved.

18
19 **Q. Mr. Sharfman raises a concern that “GSC-2 excess generation customers only receive**
20 **the energy charge as a credit,” while “GSC-1 customers receive the full PPL PTC which**
21 **includes capacity, transmission, and ancillary services, ISO and administrative fees, and**
22 **other attributes in addition to energy.” (CGC St. No. 1, pp. 16-17.) Please respond.**

1 A. I disagree with Mr. Sharfman's statement. Customer-generators being paid out at the GSC-2
2 PTC also includes transmission costs and administrative costs in addition to the energy costs.

3
4 **Q. Do you agree with Mr. Sharfman that PPL Electric's MRPL proposal would "stand in**
5 **opposition to Pennsylvania's AEPS compliance path" (CGC St. No. 1, p. 18)?**

6 A. No, because Mr. Sharfman grossly oversimplifies the goals of the AEPS Act. According to
7 Mr. Sharfman, the sole intent of the AEPS Act is to increase renewable generation in
8 Pennsylvania. I am advised by counsel that the Alternative Energy Portfolio Standards seek
9 to ensure that "a certain amount of energy sold from alternative energy sources is included as
10 part of the sources of electric generation by electric utilities within this Commonwealth." 73
11 Pa. C.S. § 1648.2. Despite Mr. Sharfman's assertion, the goal of the AEPS Act was never to
12 increase renewable generation in Pennsylvania regardless of cost or impact to the other
13 customers. Rather, by setting specific targets, it was always the intent of the AEPS Act to
14 promote alternative energy sources while balancing costs to other customers.

15
16 **Q. Do you agree with Mr. Sharfman that "[o]utside of the fact that a solar array generates**
17 **power and load consumes it, there is no reason to suggest that any industrial load would**
18 **behave in the same manner as a solar generator that depends on hours of sunlight"**
19 **(CGC St. No. 1, p. 19)?**

20 A. Mr. Sharfman's contention lacks merit because all rate classes include users with dissimilar
21 usage patterns. According to Mr. Sharfman's logic, no-load customer-generators should not
22 be in the Small C&I class either as their operation has nothing in common with the usage of

1 patterns of other Small C&I customers. Ultimately, the question is whether the customer
2 classification is reasonable. It is the Company's position that a no-load customer-generator
3 with 3 MW (or 3,000 kW) of export is more akin to a large industrial user than a Small C&I
4 customer with less than 100 kW of demand, so it is reasonable to group those no-load
5 customer-generators with Large C&I default service customers as opposed to Small C&I
6 default service customers.

7
8 **Q. Mr. Sharfman points to issues that occurred in Texas due to Winter Storm Uri in**
9 **February 2021, when residential customers were enrolled in rates that were tied to the**
10 **ERCOT LMP market, noting that the rates spiked for those customers and that Texas**
11 **banned residential customers from accessing real-time rates as a result. (CGC St. No.**
12 **1, pp. 20-21.) Do you think this example is relevant to the MRPL proposal?**

13 A. The volatility that Mr. Sharfman references is a market function and would compensate the
14 no load customer-generators more during times of grid stress. The Winter Storm Uri example
15 proves PPL Electric's position that the GSC-2 rate will more accurately compensate no-load
16 customer-generators for the value they are providing to the grid.

17
18 **Q. Why does Mr. Sharfman claim that your testimony about the harm to non-customer-**
19 **generators in GSC-1 is hard to follow?**

20 A. He alleges that "[u]tility rate classes are generally set based on electric demand and usage
21 pattern. It is not clear why a GSC-1 customer that behaves nothing like a GSC-2 customer
22 should be forced to take service under GSC-2 just because they have a solar generator on-site

1 that produces more than 100kW of electricity.” (CGC St. No. 1, p. 24.) Further, he reviews
2 my assertion that GSC-1 customers pay the “financial burden” for projects is puzzling, as the
3 installation and maintenance of solar generation is paid for by the customer generator and
4 solar company. (*Id.*) The MWh associated with solar generation offsets the generation PPL
5 Electric would be forced to purchase through load following contracts otherwise, so aside
6 from the fact that offsetting market purchased generation was the goal of AEPS to begin with,
7 the MWh generated by GSC-1 customer generators reduce the MWh PPL Electric must
8 procure to supply the GSC-1 class. (*Id.*) As such, Mr. Sharfman expects the GSC-1 PTC to
9 decline over time, which benefits the GSC-1 class. (*Id.*)
10

11 **Q. Is Mr. Sharfman’s position correct?**

12 A. No. While the customer may not “behave” like a traditional GSC-2 load in terms of
13 consumption, their generation capability creates planning and cost implications similar to
14 those in GSC-2. Likewise, no-load customer-generators do not behave like other GSC-1
15 customers either. If anything, Mr. Sharfman is arguing that no-load customer-generators
16 should be in a separate default service rate class by themselves. **[BEGIN HIGHLY**
17 **CONFIDENTIAL]** Moreover, as noted previously and shown in PPL Electric Exhibit AC-
18 4R (HIGHLY CONFIDENTIAL), CGC members based their projected revenues on
19 substantial increases in the PTC over time. Therefore, Mr. Sharfman’s claim is directly
20 contradicted by the companies on whose behalf he is testifying in this case. **[END HIGHLY**
21 **CONFIDENTIAL]**
22

1 **Q. Please also respond to Mr. Sharfman’s claim that “PPL’s assertion that existing GSC-1**
2 **customers impose a cost burden on other customers is also inconsistent with the**
3 **Company’s own evidence regarding the system-level benefits of distributed energy**
4 **resources (‘DERs’).” (CGC St. No. 1, p. 25.)**

5 A. PPL Electric’s assertion regarding cost burden is based on the fact that existing GSC-1
6 customers with large-scale DERs receive full retail PTC payments for excess generation that
7 is far above the wholesale market value of that energy. These inflated payouts are recovered
8 from other default service customers, creating a direct cost shift. System-level benefits are
9 real but generalized. They accrue to the grid as a whole and do not offset the incremental
10 financial obligations imposed on non-participating customers under current tariff rules. Cost-
11 causation principles require that compensation reflect the actual avoided costs and reliability
12 impacts, not unrelated benefits. Therefore, recognizing DER benefits does not eliminate the
13 need to address inequitable cost recovery and ensure that pricing aligns with market
14 fundamentals. Additionally, the Company’s proposal continues to compensate no-load
15 customer-generators for their benefits in a manner consistent with the AEPS Act.

16
17 **Q. Please address Mr. Sharfman’s claims that PPL Electric has not provided any**
18 **“empirical” evidence that its current tariff misaligns cost responsibility and that no-load**
19 **customer-generators create a cost burden comparable to large industrial customers.**
20 **(CGC St. No. 1, pp. 25-26.)**

21 A. Mr. Sharfman confuses the Company’s position that no-load customer-generators will
22 drastically increase the cost of default service for Small C&I customers, with the costs that

1 these customer-generators will place on the distribution system. I have provided evidence
2 that without the MRPL proposal the Small C&I PTC will continue to increase to unaffordable
3 levels. I do not agree with Mr. Sharfman's statements about the benefits that no-load
4 customer-generators will provide, and regardless, those alleged benefits are irrelevant to
5 deciding whether to approve the Company's MRPL proposal.
6

7 **Q. Mr. Sharfman also attempts to criticize your direct testimony by claiming that you**
8 **provided no evidence that Small C&I customers suffer higher default-service**
9 **procurement costs due to net metering exports and that you provided no study**
10 **comparing the cost to serve a 3 MW net metered facility to a 3 MW load consistent**
11 **industrial facility. (CGC St. No. 1, pp. 26-27.) Please respond.**

12 A. Excess generation from net-metered customers is cashed out at the full retail PTC, which far
13 exceeds the wholesale cost PPL Electric pays for default supply. This disparity creates
14 incremental costs that must be recovered from other customers in the same class, regardless
15 of facility size. This was demonstrated in the analysis provided in my direct testimony,
16 projecting the increase in net metering cashouts and the impact on the Small C&I PTC, which
17 is imposed as a cost burden to default service customers. The comparison to the cost to serve
18 a 3 MW load customer is irrelevant because the Company is not proposing to change these
19 customers' distribution rate schedule.
20

21 **Q. Mr. Sharfman also rejects PPL Electric's evidence that the PTC could reach \$300 per**
22 **MWh by 2028, pointing to his Exhibit CGC 3.0 that provides Amerex peak forwards**

1 **for the PJM PPL zone and estimated GSC-1 PTC values based on the Amerex forwards.**
2 **(CGC St. No. 1, pp. 27-28.) Please respond.**

3 A. The analysis performed by the Company was not to be used as a PTC price forecast of an
4 expected dollar per MWh value, but rather to show the directional and magnitude impact of
5 the increase in net metering expense related to excess generation annual cashouts while
6 holding all other PTC inputs constant. In addition, the analysis does not suggest a \$300/MWh
7 PTC in any scenario in 2028. The analysis shows a PTC of \$150/MWh in the highest case
8 scenario for 2028. The analysis included in the PTC the Transmission Service Charge
9 (“TSC”) and the cost of the full-requirements, load following contracts, which include energy,
10 capacity, ancillary services, AECs, and other costs. In fact, the average full requirements price
11 in the Company’s analysis is \$0.08064/kWh, and is almost the same as the average Amerex
12 forward prices in Exhibit CGC 3.0 of \$0.07894/kWh, which do not include the other
13 aforementioned cost components included in the full requirements contracts. However, the
14 power forwards referenced in Exhibit CGC 3.0 only include the energy component in their
15 forecast and do not account for the additional cost elements. The GSC-1 rate also includes
16 administrative costs, net metering costs, and the impact of reconciliation in addition to pure
17 generation supply costs, as shown in PPL Electric Exhibit AC-2R.

18
19 **Q. If the Commission adopts PPL Electric’s MRPL proposal, Mr. Sharfman recommends**
20 **that the Commission apply the MRPL to new customer-generators only, essentially**
21 **grandfathering in the existing customer-generators. (CGC St. No. 1, pp. 29-30.) JSA**
22 **Witness Barnes makes a similar recommendation that it is necessary to establish “legacy**

1 **rights” due to the financial investment made by customer-generators and the principle**
2 **of “gradualism” to prevent “rate shock.” (JSA St. No. 2, pp. 32-37.) Do you agree with**
3 **these recommendations?**

4 A. No, I do not. Grandfathering customer-generators would undermine cost equity and non-
5 customer generators will continue to bear disproportionate costs. The Commission should
6 apply the MRPL proposal uniformly to all customer-generators to ensure fairness for all
7 customers. The Company changes its rates from time to time without grandfathering for other
8 customers. Also, as explained in Mr. Olsen’s rebuttal testimony (PPL Electric St. No. 14-R),
9 it could have been anticipated that the compensation model may change for no load customer-
10 generators which does not support these grandfathering proposals.

11 Additionally, Mr. Sharfman errs in relying on the stranded cost recovery that was
12 permitted for electric utilities as part of restructuring of the retail electric market in
13 Pennsylvania. (*See* CGC St. No. 1, p. 29.) Electric utilities, unlike these solar developers, are
14 guaranteed an opportunity to earn a just and reasonable return on their investments. In
15 exchange, the electric utilities’ rates and services are regulated by the Commission. *See, e.g.,*
16 66 Pa. C.S. §§ 1301, 1501. I am advised by counsel that is why the General Assembly needed
17 to ensure stranded cost recovery as part of the Electricity Generation Customer Choice and
18 Competition Act (“Competition Act”). *See, e.g.,* 66 Pa. C.S. §§ 2803, 2804(13)-(14), 2808.
19 Solar developers, however, operate in a competitive, unregulated market, and the Commission
20 does not regulate their service or the rates they charge. Thus, in exchange, they are not
21 guaranteed and should not be guaranteed any return on their investments, particularly when
22 the Company’s customers would be footing the bill for the developers’ risky investments.

1
2 **Q. JSA witness Barnes also contends that the “establishment of legacy rights for Existing**
3 **facilities” is “consistent with [his] understanding of the Commission’s determination in**
4 **the UGI Proceeding and related default service plan,” on the grounds that no existing**
5 **customer-generators were affected by UGI Electric’s change in customer classification.**
6 **(JSA St. No. 2, p. 40.) Please respond.**

7 A. Although no existing facilities were affected by the Commission’s ruling in the UGI Electric
8 Default Service Plan V (“DSP V”) proceeding, Penn Renewables LLC (“Penn Renewables”) had 12 solar array projects in development in UGI Electric’s service territory that would be
9 affected by UGI Electric’s Supply Peak Load Impact (“SPLI”) proposal in that proceeding.
10 *See Petition of UGI Utilities, Inc. - Electric Division for Approval of a Default Service Plan*
11 *for the Period of June 1, 2025 through May 31, 2029*, Docket Nos. P-2024-3049343, *et al.*, p.
12 24 (Order entered Feb. 20, 2025). Penn Renewables opposed the SPLI proposal and has
13 continued to dispute the Commission’s approval of that proposal on appeal to the
14 Commonwealth Court.

15
16 Moreover, the Commission recently approved the Joint Petition for Approval of the
17 Non-Unanimous Settlement in Citizens’ Electric’s 2025 Rate Case, as modified by the
18 Commission. *See Pa. PUC v. Citizens’ Electric Co.*, Docket Nos. R-2025-3054394, *et al.*,
19 pp. 68-76 (Order entered Jan. 15, 2026) (“*Citizens’ Electric*”). In that proceeding, several
20 solar developers challenged Citizens’ Electric’s billing demand proposal, which is similar to
21 UGI Electric’s DSP V customer classification and PPL Electric’s MRPL proposal. Notably,
22 one of the solar developers’ witnesses was JSA witness Lucas, who testified that “[t]he

1 practical effect” of Citizens’ Electric’s proposal “is that the 13 customer-generators on the
2 GLP-1 tariff will see a massive increase in distribution costs, while the 1,124 non-customer
3 generators on the GLP-1 tariff will see a non-trivial distribution bill reduction.” (Solar
4 Projects Main Brief, *Pa. PUC v. Citizens’ Electric Co.*, Docket Nos. R-2025-3054394, *et al.*,
5 p. 27) (quoting Solar Projects’ St. No. 2-SR, p. 21).) In the end, the Commission rejected the
6 Solar Projects’ arguments and approved Citizens’ Electric’s billing demand proposal. Thus,
7 the Citizens’ Electric case directly undercuts Mr. Barnes’s claim that the establishment of
8 legacy rights may be supported by the Commission.

9
10 **Q. Do you have any other concerns with JSA Witness Barnes’s proposal to establish legacy**
11 **rights for existing facilities and transition facilities?**

12 A. Yes. Foremost, PPL Electric maintains that its MRPL proposal should be approved in full by
13 the Commission, and nothing presented by the other parties’ witnesses warrants deviating
14 from the Commission’s well-established precedent in the UGI Electric DSP V case and in the
15 very recent Citizens’ Electric 2025 Rate Case. Across the Commonwealth, utilities are
16 sounding the alarm about the adverse impact that the no-load customer-generators are having
17 and are projected to have on customers’ default service rates. These concerns are heightened
18 in PPL Electric’s service territory, where the amount of existing and projected no-load
19 customer-generators outpace peer electric utilities, including UGI Electric and Citizens’
20 Electric, whose similar proposals to deal with this problem were approved by the
21 Commission. No legacy rights were established for existing or transition facilities in those

1 cases, and none should be established here either, to ensure that non-customer-generators are
2 not unduly harmed.

3 Moreover, all no-load customer generators impact the default service rates for non-
4 customer generator customers, due to the increased costs incurred with compensating them
5 for their excess generation as opposed to procuring cheaper supply on the wholesale market.
6 Grandfathering any customer-generators would undermine cost equity, as non-customer
7 generators would continue to bear disproportionate costs. The Commission should apply the
8 MRPL proposal uniformly to all customer-generators to ensure fairness for all customers.

9 In addition, Mr. Barnes's alternative proposal has multiple issues. Mr. Barnes even
10 highlights one of them in his direct testimony, as he states, "I appreciate that my proposal
11 would not allow the Commission or PPL to know the full volume of Transition Facilities that
12 may qualify for legacy rights in advance, prior to the election process." (JSA St. No. 2, p.
13 42.) Therefore, he offers that "the PaPUC could establish a maximum volume of project MWs
14 in its final order in this case," which could be used to determine which transition facilities can
15 qualify for legacy rights depending on the date that the applicant "executed the NoCI." (JSA
16 St. No. 2, p. 42.) He fails to specify, however, what the maximum volume of project MWs
17 would be under his proposal. Furthermore, there are numerous problems with the AEC
18 conveyance aspect of his proposal, including, but not limited to, necessary modifications to
19 PPL Electric's existing DSP Plan that would need to be approved by the Commission. Yet,
20 Mr. Barnes's proposal envisions PPL Electric sending notices to transition facilities within 45
21 days of the Commission's approval of the compliance tariff supplement. Based on my

1 experience, there is no practical way for PPL Electric to petition for and receive approval of
2 modifications to its DSP Plan in that timeframe.

3 On top of that, Mr. Barnes's proposed AEC transfer requirement is unnecessary,
4 impractical, and inconsistent with existing AEPS compliance mechanisms. Mr. Barnes notes
5 that his proposal would require the Commission to "establish a proxy AEC price for this
6 transaction since in reality the AECs [would be] conveyed to PPL at a nominal zero cost."
7 (JSA St. No. 2, p. 44.) Determining a proxy AEC price would require ongoing regulatory
8 oversight and introduce complexity without delivering meaningful benefits. PPL Electric
9 already satisfies AEPS obligations through its DSP procurement plan, making this proposal
10 redundant. Moreover, compelling customers to transfer AECs without compensation could
11 undermine incentives for distributed generation and create administrative burdens that are
12 outside the scope of this proceeding.

13 Additionally, Mr. Barnes's proposal appears to contemplate subsidization by
14 residential customers of small commercial customers' default service costs. On page 44 of
15 his direct testimony, he states, "In other words, residential customers would pay for these
16 AECs, the same as they would if PPL secured them through an RFP, and the resulting revenue
17 would benefit the small commercial GSC-1 rate class." (JSA St. No. 2, p. 44.)

18 Mr. Barnes also fails to account for the time and expense that PPL Electric would need
19 to devote to contracting individually with each of these transition facilities agreeing to convey
20 their AECs to the Company, along with the time and expense needed to enforce those
21 contracts if the facilities fail to timely convey their AECs to PPL Electric.

22 Finally, while Mr. Barnes cites Section 75.14(d) of the Commission's regulations as

1 support for his AEC conveyance proposal, he overlooks how the regulation contemplates that
2 an EDC may need to “supply additional metering equipment” in order “to qualify the
3 alternative energy credit.” *Id.* The costs for additional metering equipment must be incurred
4 at “the EDC’s expense” under the regulation. *Id.* If the Company incurs costs additional
5 metering costs would be passed onto ratepayers and are not factored into Mr. Barnes’s
6 analysis. Thus, Mr. Barnes’s proposed alternative has too many unanswered questions to
7 warrant further consideration.

8
9 **Q. JSA witness Lucas opposes the Company’s MRPL proposal and asserts that the**
10 **Company has not sufficiently demonstrated the need for the proposal. (JSA St. No. 1,**
11 **pp. 6-7.) As such, he recommends that the Commission reject the MRPL proposal. (JSA**
12 **St. No. 1, p. 7.) What are some arguments that Mr. Lucas raises in support of his**
13 **position?**

14 A. He argues that the Company’s proposal is unsupported, claiming that PPL Electric has not
15 shown that front-of-the-meter distributed generation causes cost shifts or grid stress. He
16 further asserts that the Company’s “all-else-equal” analysis is flawed because it assumes
17 purchasing more energy than needed. He identifies four alleged errors in the Company’s
18 cost-shift analysis: incorrect cancellation-rate assumptions, overstated generation forecasts,
19 use of constant procurement costs, and failure to account for benefits from FTM DG.
20 According to Mr. Lucas, these issues render the Company’s analyses inconsistent with
21 real-world procurement practices. (JSA St. No. 1, p. 6.)

Moreover, he asserts that the Company's testimony conflicts with its discovery responses, which he claims show that PPL Electric's distribution system can already accommodate FTM DG power flows and that any required upgrades are fully paid by customer-generators. He also argues that using MRPL is an inappropriate metric for assigning customers to GSC-1 or GSC-2, and contends that relying on the highest 15-minute annual load—rather than PJM peak-based measures tied to capacity costs—violates fundamental cost-causation principles. (*Id.*)

Q. Do you have any initial observations about the use of the term “FTM DG”?

A. Yes. FTM DG necessarily implies that the generation facility is not located behind the meter and, therefore, not being used to offset load at the customer location. In that respect, FTM DG is no different than any other generation facility that interconnects directly with an electric system. That only lends further support to classifying them in accordance with the proposed MRPL. They should not be treated the same as behind-the-meter generation because they are different.

Q. Do you have any other initial observations about Mr. Lucas's testimony?

A. Yes. As noted above, the Commission recently approved a proposal by Citizens' Electric that is similar to PPL Electric's MRPL on January 15, 2026, in Citizens' Electric's 2025 Rate Case. I note that Mr. Lucas testified on behalf of the “Solar Projects” in opposition to Citizens' Electric's proposal in that proceeding and raised arguments similar to the ones he offers in this proceeding. Ultimately, the Commission rejected the Solar Projects' arguments and

1 approved Citizens' Electric's billing demand proposal. From my perspective, the
2 Commission should follow suit here and reject Mr. Lucas's claims.

3
4 **Q. Please respond to Mr. Lucas's claim that the Company's proposal is poorly supported**
5 **and that its argument that these no-load customer-generators cause a cost shift to non-**
6 **customer-generators is not supported. (JSA St. No. 1, pp. 6, 17, 48-49.)**

7 A. The Company's proposal addresses a real and measurable cost shift. Even fellow JSA witness
8 Barnes acknowledges that the value of AECs must be considered to offset the gap. (See JSA
9 St. No. 2, p. 42.) Mr. Barnes's testimony demonstrates that without incorporating AEC value,
10 there is indeed a shortfall, or that a cost shift exists. The need to rely on AECs to "make up
11 the gap" is an implicit admission that the current structure does not fully recover costs from
12 customer-generators. This supports PPL Electric's position that the existing framework is
13 inadequate and requires reform.

14
15 **Q. Do you agree with Mr. Lucas you presented an "all else equal" analysis that results in**
16 **the purchase of two units of energy to serve one unit of load (JSA St. No. 1, pp. 6, 44-45,**
17 **48-49)?**

18 A. No, I do not agree with Mr. Lucas's characterization. The Company's analysis was intended
19 to isolate the direction and magnitude of net metering expenses related to excess generation
20 compensation. Although additional FTM DG could reduce overall supply procurement, other
21 factors such as growing demand or customer switching could increase procurement
22 requirements and offset the impact of FTM DG excess generation. For this reason, the

1 Company kept the other variables constant in its analysis. This approach ensures clarity in
2 evaluating the incremental cost impact and counters the assertion that the analysis results in
3 purchasing two units of energy to serve one unit of load.
4

5 **Q. Mr. Lucas asserts that the Company's customer classification methodology runs**
6 **contrary to cost causation principles and that NCP demand should be used in**
7 **"extremely limited cases" in cost of service and rate design. (JSA St. No. 1, pp. 22, 33-**
8 **36.) Please respond.**

9 A. Mr. Lucas' analysis relies on the cost to serve no-load customer-generators from a distribution
10 perspective and ignores the cost to serve these customers from a default service perspective.
11 Additionally, in rate design the Company must consider equitably serving the entire class, not
12 just one set of customers to the detriment of others. The MRPL proposal is intended to classify
13 the large no-load customer-generators with similarly situated Large C&I customers for the
14 purposes of default service. As such, the MRPL proposal prevents Small C&I customers from
15 unduly subsidizing large industrial scale no load customer-generators. The Commission
16 recently recognized the importance of eliminating that subsidy in the recent Citizens' Electric
17 2025 Rate Case, where the Commission cited Section 2807(e)(7) of the Public Utility Code
18 and explained that the statute "prohibits a utility from charging default service rates to one
19 class that subsidize the costs for other customer classes." *Citizens' Electric*, p. 71.
20 Importantly, "Citizens' proposed new definition for Billing Demand," which is similar to PPL
21 Electric's MRPL proposal, "offers a solution to the subsidization issue posed by large
22 customer-generators." *Id.*

1
2 **Q. Mr. Lucas asserts that PPL Electric treats “FTM DG customers as ‘small’ for purposes**
3 **of their distribution rate as a customer, but inconsistently characterizes these same**
4 **customers as ‘large’ for purposes of compensation for excess generation from their**
5 **alternative energy systems.” (JSA St. No. 1, p. 24.) Do you believe that such a criticism**
6 **has merit?**

7 A. No, and this is no different than what the Company does today. There are GS-3 customers
8 with peak demands above and below 100 MW. These customers are segregated as Large C&I
9 and Small C&I for default service purposes despite being in the same distribution rate
10 schedule. Providing customers default service is fundamentally different than providing
11 distribution service and it is reasonable to have different classifications for these two distinct
12 services.

13
14 **Q. Do you agree with the alleged four problems that Mr. Lucas identifies with respect to**
15 **PPL Electric’s analysis of the projected costs to be incurred by Rate GSC-1 non-**
16 **customer-generators if the Company’s proposal is denied (JSA St. No. 1, pp. 38-48)?**

17 A. No.

18
19 **Q. Why is that?**

20 A. The first problem Mr. Lucas identifies is an error in the cancellation rate assumptions,
21 particularly the 36% cancellation rate scenario. However, the 36% cancellation rate is the
22 actual cancellation rate and is used as the base case, which essentially captures the cancelled

1 projects and therefore acts as 0% incremental cancellations. Next is an alleged overestimation
2 of generation from FTM DG projects. The Company maintains that it used appropriate
3 estimates for the amount of generation anticipated. Yet, even if it overestimated the amount
4 of generation from no load customer-generators, it would only lessen the magnitude of the
5 cross-subsidization, not negate the fact that it is occurring. The third issue identified is the
6 use of constant energy procurement costs. The Company's analysis was intended to isolate
7 the directionality and magnitude impact of one net metering expenses related to excess
8 generation compensation. Although the addition of more FTM DG could reduce the overall
9 supply procurement, there could be more load added to the procurement as a result of growing
10 demand or customer switching, which would offset the FTM DG excess generation.
11 Therefore, the Company kept the procurement cost variable constant. Finally, Mr. Lucas
12 alleges the Company fails to recognize any benefits from FTM DG projects. As I addressed
13 with the third concern, inputs were kept constant to isolate the impact of one variable and that
14 although FTM DG could reduce forecasted peaks, other market factors, such as higher than
15 projected peaks or FTM DG not being available during those peaks, could offset those benefits
16 and were therefore not included.

17 Additionally, while the cost impact to the Small C&I default service rate class caused
18 the Company to evaluate its classification of default service customers, the inclusion of no-
19 load customer-generators would be appropriate even if the projected projects do not
20 materialize. A 3-MW no-load customer-generator should be in the GSC-2 rate class
21 regardless of how many of these kinds of customer-generators exist.
22

1 **Q. JSA witness Barnes also testifies about the Company’s MRPL proposal and presents an**
2 **alternative to addressing the GSC-1 rate impacts due to FTM DG. (JSA St. No. 2, p. 4.)**
3 **Could you please summarize his position and recommendation?**

4 A. Mr. Barnes proposes three ways to protect GSC-1 customers and FTM DG owners: (1) reflect
5 the value of excess NEM generation in GSC-1 load calculations; (2) adjust the GSC-2 rate to
6 make excess-generation compensation cost-based; and (3) grant legacy rights to certain
7 existing or advanced projects. He recommends allowing negative peak loads to reduce
8 capacity and transmission allocations, revising GSC-2 compensation to include credits for
9 negative peaks, and establishing legacy rights for operational, under-construction, or
10 qualifying planned projects—subject in some cases to AEC transfers and additional deposit
11 requirements. (JSA St. No. 1, p. 4.)

12
13 **Q. Do you have any initial observations about Mr. Barnes’s direct testimony?**

14 A. Yes, Mr. Barnes appears to concede, unlike his fellow JSA witness, Mr. Lucas, that there is a
15 cost shift to non-customer-generators in Rate GSC-1 due to no-load customer-generators. In
16 fact, even under Mr. Barnes’s assumptions and calculations, he admits that there is a “small
17 gap between the market-based cost-savings value of FTM DG excess generation and the GSC-
18 1 cash-out rate if AEC value is excluded.” (JSA St. No. 2, p. 21.) That “small gap” is evidence
19 of such a cost shift. As a result, he puts forward an AEC conveyance proposal to “bridge the
20 ‘value gap’ between the GSC-1 excess generation cash-out rate and the cost reductions that
21 excess generation produces for default service (inclusive of transmission).” (JSA St. No. 1,

1 pp. 42-43.) From that standpoint, it appears that the JSA witnesses' positions on whether a
2 cost shift exists are inconsistent.

3
4 **Q. Do you believe that Mr. Barnes accurately defines the “problem” that PPL Electric’s**
5 **proposal is intended to address (JSA St. No. 2, pp. 7-9)?**

6 A. Mr. Barnes' characterization of the “problem” PPL Electric's proposal seeks to address does
7 not accurately reflect the Company's intent. His framing centers on cost allocation and
8 compensation for excess generation. The purpose of the proposal is to ensure that customers
9 are classified into the appropriate rate schedules based on objective, measurable criteria, such
10 as MRPL, rather than subjective interpretations of system economics. This approach promotes
11 fairness, consistency, and transparency in rate design. It is not intended to redefine cost
12 causation principles or alter demand forecasting methodologies, but to maintain clear and
13 equitable standards for rate classification.

14
15 **Q. Do you agree with Mr. Barnes that the Company's evaluation of how net metering**
16 **excess generation affects generation supply and transmission costs is “incomplete and**
17 **consequently biased,” as it “fails to reflect that excess generation produces actual and**
18 **readily quantifiable cost reductions that offset those costs” (JSA St. No. 2, pp. 10-11)?**

19 A. No, I do not agree with Mr. Barnes' characterization. The Company's evaluation
20 appropriately focuses on cost causation and PPL Electric's obligations in procuring capacity
21 and transmission services to maintain reliable electric service for all customers. While excess
22 generation may provide some energy-related benefits, those benefits do not eliminate the fixed

1 costs associated with capacity and transmission that remain necessary regardless of distributed
2 generation output. The Small C&I customers who are paying higher default service costs do
3 not realize the alleged benefits that Mr. Barnes discusses in his testimony.
4

5 **Q. Mr. Barnes also criticizes the Company's practice of assigning zero load instead of**
6 **negative load and argues that "nothing" in PPL Electric's Attachment M-2 of its OATT**
7 **"precludes a customer from being designated with a negative PLC" and that nothing in**
8 **the broader PJM rules precludes it either, pointing to ComEd receiving approval to use**
9 **negative PLCs for NEM and community solar. (JSA St. No. 2, pp. 11-17.) Do you agree?**

10 A. No, I do not agree with Mr. Barnes' assertion. While PJM rules do not explicitly prohibit
11 negative PLCs, the Company's approach of assigning zero load is consistent with PJM's
12 established methodology and the principles underlying capacity obligations. If negative tags
13 are established, the costs would increase for all non-generating customers because the costs
14 are still scaled to a single peak value. Importantly, the comparison to ComEd is not
15 appropriate. In Illinois, the Illinois Power Agency ("IPA"), not the individual electric
16 distribution companies ("EDCs"), is responsible for procuring supply to serve default service
17 customers. This means ComEd does not procure or settle its own default supply in the PJM
18 markets. As a result, ComEd does not carry the market exposure or settlement responsibility
19 associated with the capacity and energy obligations tied to its customers' PLCs. Instead, the
20 IPA, as the centralized state procurement entity, absorbs the risk associated with any volatility
21 or distortions in PLC assignments, including negative PLC values.

1 This structure fundamentally differs from PPL Electric's role. PPL Electric is directly
2 responsible for procuring full-requirements supply, managing PJM settlements, and carrying
3 the financial and operational risk tied to PLC assignments for customers served under the
4 Price-to-Compare ("PTC"). Assigning negative PLCs would artificially reduce the
5 Company's load obligation in a way that does not reflect actual system capacity needs and
6 would shift risk and cost inequities onto other customers. By contrast, PJM's PLC
7 methodology is designed to measure a customer's contribution to system peak load. Setting
8 PLCs to zero for customers whose net metering production exceeds their load preserves that
9 principle without creating distortions in PJM settlement processes. Negative PLCs would
10 improperly imply that a customer provides a capacity benefit to the system, even though
11 behind-the-meter generation is not dispatchable by PJM and does not reduce PJM's forward
12 capacity requirements. For these reasons, assigning a zero PLC aligns with PJM's framework,
13 avoids introducing risks and settlement distortions for default service procurement, and is
14 consistent with how capacity responsibilities function in jurisdictions, like Pennsylvania,
15 where EDCs, not state agencies, procure and settle default supply.

16 Lastly, it is my understanding that the negative PLCs that ComEd use are for the
17 purposes of incentivizing certain large customer renewable investments. The negative PLCs
18 are part of a coordinated state renewable policy. Additionally, the negative PLCs are not used
19 to settle the PJM market for capacity or transmission service. ComEd and PPL Electric both
20 do not allow negative PLCs for capacity or transmission purposes. Furthermore, because
21 Pennsylvania does not have a similar large customer renewables program like Illinois, it

1 would be inappropriate to copy the negative PLC model. As such, Mr. Barnes's reliance on
2 the IPA's treatment of negative PLCs is misplaced.

3
4 **Q. Mr. Barnes presents analyses for assessing the value of net metering excess generation**
5 **(including his use of Demand Induced Market Price Effects ("DRIPE")) and notes that**
6 **he used two scenarios: one based on how PPL Electric presently accounts for NEM**
7 **excess generation by small commercial GSC-1 customers in its default service supply**
8 **plan, and a second based on a wholesale market value approach that reflects the value**
9 **of NEM excess generation for a wholesale generation supplier that serves small**
10 **commercial GSC-1 loads. (JSA St. No. 2, pp. 19-31.) Do you have any issues with Mr.**
11 **Barnes's analyses?**

12 **A.** Mr. Barnes' analyses, including his use of DRIPE and wholesale market valuation scenarios,
13 are not relevant to this issue. These approaches introduce speculative assumptions and
14 wholesale market constructs that fall outside the scope of this proceeding. The Company's
15 proposal is focused on ensuring accurate and equitable classification of customers into rate
16 schedules based on objective criteria, not on recalculating compensation for excess generation
17 or embedding capacity values into retail rates. Accordingly, Mr. Barnes's valuation exercises
18 should not influence the Commission's determination in this matter.

19
20 **Q. Mr. Barnes also argues that the generation capacity portion of supply costs should be**
21 **included in the GSC-2 NEM cash-out rate and explains how that would function,**
22 **arguing that doing so would not involve "any significant additional complexities," as**

1 **“PPL is already measuring PJM 5CP demands for the purpose of establishing customer**
2 **capacity charges.” (JSA St. No. 2, pp. 29-32.) Do you agree?**

3 A. No, I do not agree with Mr. Barnes’ position. Including the generation capacity portion of
4 supply costs in the GSC-2 NEM cashout rate would effectively compensate customer-
5 generators for capacity when their capacity obligation is zero. While PPL Electric does
6 measure PJM 5CP demands, those measurements are used solely to allocate capacity
7 obligations for load-serving entities, not to calculate retail credits for excess generation.
8 Incorporating capacity value into cashout rates would misalign with cost-causation principles
9 and introduce unnecessary complexity into billing and settlement processes, contrary to Mr.
10 Barnes’ assertion.

11
12 **Q. Mr. Harbach also claims that the Alternative Energy Portfolio Standards (“AEPS”) Act**
13 **does not authorize utilities or the Commission to modify procurement classes or rate**
14 **classes in order to reduce the compensation to customer generators to offset the alleged**
15 **cost of net metering. (PDMP St. No. 1, p. 9.) He further asserts that the Commission**
16 **and PPL Electric should ensure that all elements of default service, not just the per kWh**
17 **charge. (PDMP St. No. 1, p. 10.) Please respond.**

18 A. As I explained previously, the Commission has rejected these legal arguments in the UGI
19 Electric and Citizens’ Electric cases. I am advised by counsel that PPL Electric’s proposal
20 comports with the AEPS Act and that the Company’s proposal would continue to compensate
21 customer-generators in compliance with the AEPS Act and the Commission’s regulations.
22 These legal issues will be further addressed in PPL Electric’s briefs.

1
2 **Q. PDMP witness Rensch alleges that without net metering compensation at the present**
3 **level, digester projects would not be viable. (PDMP St. No. 2, p. 6.) He then presents a**
4 **series of possible ramifications due to making digesters uneconomic. (PDMP St. No. 2,**
5 **pp. 7-8.) Please respond.**

6 A. The viability of digester projects and the broader policy implications raised by Mr. Rensch
7 are outside the scope of designing default service rates. While these concerns are legitimate,
8 they are more appropriately addressed through other mechanisms, such as environmental and
9 energy policy frameworks administered by agencies like the Pennsylvania Department of
10 Environmental Protection (“DEP”). The purpose of this case is to ensure fair and accurate
11 rate design for default service, not to resolve issues related to renewable project economics or
12 environmental compliance.

13
14 **Q. Walmart witness Lyon recommends that the Commission reject the Company’s MRPL**
15 **proposal because it would “abruptly...shift customer-generators above 100kW to**
16 **hourly LMP-based kWh generation valuation” and change project value propositions**
17 **and “disincentivize generation in PPL territory when capacity markets are seeing**
18 **extremely high prices and forecasts are trending toward increasing demand.”**
19 **(Walmart St. No. 1, p. 21.) Do you agree?**

20 A. As I have explained previously, PPL Electric’s proposal would properly classify no-load
21 customer-generators and ensure that the Company can meet its obligations under the Public
22 Utility Code to procure reasonable and adequate default service supply at the least cost to

1 customers over time. Furthermore, the Company's analyses show that without its MRPL
2 proposal being approved, the Small C&I PTC rate will increase significantly. Also, only 18
3 existing customer-generators would be reclassified from GSC-1 to GSC-2 if the Company's
4 proposal is approved.

5
6 **Q. Do you agree with Mr. Lyon's claim that Pennsylvania does not have an over-supply of**
7 **generation that could justify disincentivizing onsite solar development (Walmart St. No.**
8 **1, p. 20)?**

9 A. No, I do not agree with Mr. Lyon's claim. The Company's proposal is not predicated on
10 whether Pennsylvania has an over-supply of generation, nor is it intended to disincentivize
11 onsite solar development. The purpose of the MRPL approach is to ensure accurate and
12 equitable classification of customers into appropriate default service rate classes based on
13 objective criteria. This methodology aligns pricing with actual market conditions and cost-
14 causation principles, promoting fairness across all customer groups. Broader questions
15 regarding generation adequacy and renewable energy incentives fall under state energy policy
16 and other regulatory programs, not the design of default service rates.

17
18 **Q. In alleged support of his opposition to PPL Electric's MRPL proposal, Mr. Lyon asserts**
19 **that "Monitoring Analytics and PJM...analyses have documented tightening**
20 **fundamentals, price signals of scarcity in recent capacity auctions, and scenarios where**
21 **local constraints or retirements could cause shortfalls – especially if demand grows**
22 **faster than expected." (Walmart St. No. 1, p. 20.) What is your response?**

1 A. Mr. Lyon's reference to Monitoring Analytics and PJM analyses regarding tightening
2 fundamentals and potential capacity shortfalls does not undermine the Company's MRPL
3 proposal. While PJM market dynamics may fluctuate due to retirements or demand growth,
4 these factors are addressed through PJM's capacity market mechanisms and regional planning
5 processes, not through retail rate design. The Company's proposal does not attempt to
6 influence generation adequacy or capacity market outcomes, which fall under PJM's
7 jurisdiction. I would also note that the market fundamentals referenced by Mr. Lyon would
8 likely result in higher compensation for customer-generators regardless of whether they were
9 taking service under GSC-1 or GSC-2. Indeed, as I noted previously, no-load customer-
10 generators' profits are tied to the PTC rate. Therefore, they have no financial incentive to
11 support measures that could mitigate increases in the PTC. Rather, they have every financial
12 incentive to make the PTC increase as much as possible.

13
14 **Q. Please respond to Mr. Lyon's claim that "[c]hanging the classification of customer-**
15 **generators under the GSC without robust transition protections would retroactively**
16 **alter the economics of those investments" and "create stranded value for customers who**
17 **acted reasonably under current rules." (Walmart St. No. 1, p. 21.)**

18 A. The proposal does not retroactively alter the economics of existing investments; it establishes
19 forward-looking rate classifications based on objective criteria such as Maximum Registered
20 Peak Load. This approach ensures that customers are placed in the appropriate default service
21 class consistent with cost-causation principles. The existence of prior investment decisions
22 does not preclude necessary updates to rate design that promote equity and transparency for

1 all customers. Additionally, as I stated previously, the PTC is variable regardless of which
2 rate class a customer-generator is in. It would be unreasonable for customer-generators to
3 rely on a stable PTC to make investment decisions because there will always be changes to
4 the Company's PTC.

5
6 **III. VALUE OF EDI TRANSACTION INFORMATION FOR DEFAULT SUPPLY**
7 **AND CAPACITY ALLOCATIONS**

8 **Q. What are your thoughts on RESA Witness Lacey's claim that PPL Electric benefits**
9 **from the EDI transactions and without the information from them, the Company "could**
10 **be saddled with excess default supply costs and capacity allocations from PJM" (RESA**
11 **St. No. 1, pp. 30-31)?**

12 **A.** PPL Electric does not rely on EDI transactions to determine its default service supply
13 obligations or its PJM capacity allocations. These obligations are defined strictly by PJM's
14 load and peak load contribution ("PLC") methodologies and are independent of
15 supplier-initiated EDI activity. Even in the absence of EDI transactions, PPL Electric would
16 continue to receive complete metering and settlement data that governs its capacity and default
17 service requirements. RESA Witness Lacey's assertion incorrectly assumes that customer
18 shopping information transmitted via EDI affects PJM cost assignments. No mechanism
19 exists within PJM settlement rules that would cause PPL Electric to incur excess default
20 supply or capacity costs due to lack of EDI transaction data.

1 **IV. CONCLUSION**

2 **Q. Please summarize your rebuttal testimony.**

3 A. PPL Electric's Maximum Registered Peak Load proposal ensures fair and transparent default
4 service rate classification based on objective criteria, eliminating cost shifts caused by large
5 customer-generators receiving retail-rate compensation for excess generation. It protects non-
6 generating customers, addresses affordability concerns, and aligns with cost-causation
7 principles without retroactively changing economics or disincentivizing renewable
8 development. Alternative proposals like grandfathering and AEC transfers introduce
9 unnecessary complexity and should be rejected.

10
11 **Q. Does this conclude your rebuttal testimony?**

12 A. Yes, it does.

PPL Electric Utilities Historical Price-to-Compare

Period	Residential PTC (c/kWh)	Change from Prior Period	Small C&I PTC (c/kWh)	Change from Prior Period
12/1/2025 -5/31/2026	12.953	3.71%	12.681	4.68%
6/1/2025 - 11/30/2025	12.490	15.96%	12.114	15.97%
12/1/2024 - 5/31/2025	10.771	7.28%	10.446	13.09%
6/1/2024 - 11/30/2024	10.040	-8.96%	9.237	-18.87%
12/1/2023 - 5/31/2024	11.028	-9.05%	11.386	-2.59%
6/1/2023 - 11/30/2023	12.126	-17.01%	11.689	-20.76%
12/1/2022 - 5/31/2023	14.612	18.16%	14.751	26.13%
6/1/2022 - 11/30/2022	12.366	38.31%	11.695	20.88%
1/1/2022 - 5/31/2022	8.941	-5.90%	9.675	-5.93%
12/1/2021 - 12/31/2021	9.502	25.95%	10.285	36.39%
6/1/2021 - 11/30/2021	7.544	3.10%	7.541	13.19%
12/1/2020 - 5/31/2021	7.317	0.45%	6.662	9.59%
6/1/2020 - 11/30/2020	7.284	-4.56%	6.079	-4.42%
12/1/2019 - 5/31/2020	7.632	0.62%	6.360	2.46%
6/1/2019 - 11/30/2019	7.585	7.76%	6.207	-14.32%
12/1/2018 - 5/31/2019	7.039	-5.50%	7.244	6.91%
6/1/2018 - 11/30/2018	7.449	-0.19%	6.776	-12.01%
12/1/2017 - 5/31/2018	7.463	-12.13%	7.701	2.82%
6/1/2017 - 11/30/2017	8.493	14.17%	7.490	4.07%
12/1/2016 - 5/31/2017	7.439	-0.69%	7.197	8.00%
6/1/2016 - 11/30/2016	7.491	-4.91%	6.664	-13.80%
12/1/2015 - 5/31/2016	7.878	-17.01%	7.731	-13.93%
6/1/2015-11/30/2015	9.493	-0.69%	8.982	-11.25%
3/1/2015-5/31/2015	9.559	2.59%	10.121	8.54%
12/1/2014-2/28/2015	9.318	4.04%	9.325	8.48%
10/1/2014-11/30/2014	8.956	1.61%	8.596	-2.15%
9/1/2014-9/30/2014	8.814	-2.46%	8.785	-8.35%
6/1/2014-8/31/2014	9.036	3.22%	9.585	-7.76%
3/1/2014-5/31/2014	8.754	0.00%	10.391	12.34%
12/1/2013-2/28/2014	8.754	-0.26%	9.250	21.63%
9/1/2013-11/30/2013	8.777	6.69%	7.605	-1.43%
6/1/2013-8/31/2013	8.227	13.68%	7.715	-28.66%
3/1/2013-5/31/2013	7.237	-4.20%	10.814	5.96%
12/1/2012-2/28/2013	7.554	-4.46%	10.206	-1.35%

**PPL Electric Utilities Corporation
Estimated Price-to-Compare Sample Calculation
For Illustrative Purposes Only**

Introduction:

The purpose of this document is to provide suppliers with an understanding of how the Price-to-Compare ("PTC") is calculated for all customer classes, pursuant to the Pennsylvania Public Utility Commission's ("PA PUC") Secretarial Letter issued on October 12, 2010. The data contained herein provides estimates of the PTC and reflects only a snap-shot in time.

The calculations of the PTC estimates are based on actual and estimated values. The Average Full Requirements and Average Block Prices are based on the results from the DSPP solicitations completed through July 2025. The E Factor Rate is based on the actual over/under-collection balances for April 2024 through March 2025. The Transmission Service Charge ("TSC") has been updated for the period of December 1, 2025 through November 30, 2026.

Disclaimer:

It should be noted that any and all data within this document are estimates, and actual charges will vary depending on customer demand, seasonal variations, or other factors. Forecast data is subject to change due to migration, customers leaving PPL Electric Utilities' service territory, or other events. In addition, all possible combinations of rates and surcharges have not been included in this document. Prices used in the PTC calculation are best-known values and will be updated pursuant to PPL Electric Utilities' tariff on file with the PA PUC. PPL Electric Utilities is not liable for any losses which may result from using the information contained in this document.

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Residential Class
Period: 12/1/2025 through 5/31/2026

1	Average Block Price	\$	0.03443 ⁽¹⁾
2	Times portion of Residential Load		9.22%
3	Total Weighted Block Price	\$	0.00318
4	Average Full Requirements Price	\$	0.09433 ⁽²⁾
5	Times portion of Residential Load		90.78% ⁽³⁾
6	Total Weighted Full Requirements Price	\$	0.08563
7	Subtotal (Line 3 + Line 6)	\$	0.08880
8	Multiplied by (1/(1-GRT)) <i>GRT = 5.9%</i>		1.062699
9	Block and Full Requirements Price adjusted for GRT	\$	0.09437
10	E Factor Rate	\$	(0.00188) ⁽⁴⁾
11	Administrative Charges Rate	\$	0.00142
12	Merchant Function Charge (MFC) Rate	\$	0.00209
13	Subtotal (Line 10 + Line 11 + Line 12)	\$	0.00163
14	Multiplied by (1/(1-GRT))		1.062699
15	(E Factor + Admin Charges + MFC) x GRT	\$	0.00173
16	Generation Supply Charge (Line 9 + Line 15)	\$	0.09610
17	Transmission Service Charge (TSC)	\$	0.03343 ⁽⁵⁾
18	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 16 + Line 17) x 0.00001]	\$	0.00000 ⁽⁶⁾
19	PTC Estimate - Residential Class (Line 16 + Line 17 + Line 18)	\$	0.12953

Note: Data may not total due to rounding.

- ⁽¹⁾ The average Block price is adjusted for the Loss Factor and PJM deration factor.
- ⁽²⁾ The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.
- ⁽³⁾ After the Block load has been subtracted from total load, Full Requirements represents 100% of the load.
- ⁽⁴⁾ Represents an over-collection of April 2024 through March 2025 actual revenue, which will be refunded over 12 months.
- ⁽⁵⁾ The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.
- ⁽⁶⁾ The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.

**PPL Electric Utilities Corporation
Estimated Price-to-Compare Sample Calculation
For Illustrative Purposes Only
Residential Class**

Line Item Explanations for the Residential Class:

Line 1 – An estimate of the average Block price for the applicable PTC period based on the solicitations completed.

Line 2 – Percentage represents the portion of total forecasted Residential load that is estimated to be supplied by the Block product for the applicable PTC period.

Line 3 – The weighted price of the Block product.

Line 4 – An estimate of the average Full Requirements price for the applicable PTC period based on the solicitations completed. Price includes all necessary energy, capacity, transmission other than Network Integration Transmission Service Charge (“NITS”), ancillary services, Pennsylvania Alternative Energy Portfolio Standard (“AEPS”) requirement, transmission and distribution losses and congestion management costs, and such other services or products that are required to supply the specified percentage of a supplier’s default load for a customer group set forth in a transaction confirmation pursuant to the Default Service Supply Master Agreement.

Line 5 - Percentage represents the portion of total forecasted Residential load that is estimated to be supplied by the Full Requirements product after deducting the Block product load, or 100% of the remaining Residential load.

Line 6 – The weighted price of the Full Requirements product.

Line 7 – The sum of the weighted prices for the Block, Full Requirements and Spot products.

Line 8 – Represents the gross-up effect of the statutory PA Gross Receipts Tax (“GRT”) of 5.9%:
 $(1/1-5.9\%) = 1.062699$

Line 9 – An estimate of the Block and Full Requirements weighted price adjusted for the GRT.

Line 10 – The E factor rate represents the estimated over/under collection from the prior rate period that will be recovered during the current rate period.

Line 11 – The administrative charges rate for the Residential class.

Line 12 – Represents the Merchant Function Charge (“MFC”) rate which is the provision for uncollectible accounts expense.

Line 13 – Sum of the estimate of the E factor, administrative charges and MFC.

Line 14 – Represents the gross-up effect of the statutory PA GRT of 5.9%:
 $(1/1-5.9\%) = 1.062699$

**PPL Electric Utilities Corporation
Estimated Price-to-Compare Sample Calculation
For Illustrative Purposes Only
Residential Class**

Line 15 – Sum of the estimate of the E factor, administrative charges and MFC adjusted for the GRT.

Line 16 – Represents the GSC by adding the Block and Full Requirements weighted price, including the E factor rate, administrative charges and the MFC. All components reflect the statutory PA GRT of 5.9%.

Line 17 – The Transmission Service Charge (“TSC”) as filed with the PA PUC on October 31, 2025. This is the rate set forth in PPL Electric’s tariff for December 1, 2025 through November 30, 2026 and reflects the statutory PA GRT of 5.9%.

Line 18 – The State Tax Adjustment Surcharge (“STAS”) at 0.0001% multiplied by the subtotal of the GSC and TSC. All components reflect the statutory PA GRT of 5.9%.

Line 19 – The total PTC estimate for the Residential Class in \$/kWh.

PPL Electric Utilities Corporation
Estimated Price-to-Compare Calculation
For Illustrative Purposes Only
Small Commercial & Industrial Class
Period: 12/1/2025 through 5/31/2026

1	Average Full Requirements Price	\$	0.08414 ⁽¹⁾
2	Times portion of Small Commercial and Industrial Load		100.00%
3	Total Weighted Full Requirements Price	\$	0.08414
4	Multiplied by (1/(1-GRT)) $GRT = 5.9\%$		1.062699
5	Block and Full Requirements Price adjusted for GRT	\$	0.08942
6	E Factor Rate	\$	0.00038 ⁽²⁾
7	Administrative Charges Rate	\$	0.00353
8	Merchant Function Charge (MFC) Rate	\$	0.00020
9	Subtotal (Line 6 + Line 7 + Line 8)	\$	0.00411
10	Multiplied by (1/(1-GRT))		1.062699
11	(E Factor + Admin Charges + MFC) x GRT	\$	0.00437
12	Generation Supply Charge (Line 5 + Line 11)	\$	0.09379
13	Transmission Service Charge (TSC)	\$	0.03302 ^{(3), (5)}
14	State Tax Adjustment Surcharge (STAS) @ 0.001% [(Line 12 + Line 13) x 0.00001]	\$	0.00000 ⁽⁴⁾
15	PTC Estimate - Small Commercial & Industrial Class (Line 12 + Line 13 + Line 14)	\$	0.12681

Note: Data may not total due to rounding.

- ⁽¹⁾ The average Full Requirements price is adjusted for the Loss Factor and PJM deration factor and includes AEPS compliance costs.
- ⁽²⁾ Represents an under-collection of April 2024 through March 2025 actual revenue, which will be collected over 12 months.
- ⁽³⁾ The TSC is the rate as set forth in PPL Electric's tariff and reflects the statutory PA Gross Receipts Tax (GRT) of 5.9%.
- ⁽⁴⁾ The State Tax Adjustment Surcharge reflects any incremental GRT pursuant to 72 P.S. § 8111-A(d) less any applicable refunds.
- ⁽⁵⁾ TSC rate for LP4 customers with a demand less than 100kW differs from value reflected. LP4 transmission customers receive a demand charge of \$21.647/kW.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
JOSEPH LOOKUP
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

**Topics: Large Load Interconnection
 Reliability and Performance
 Storm Restoration and Planning**

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Joseph Lookup, and my business address is 827 Hausman Road, Allentown,
4 Pennsylvania 18104.

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

7 A. I am employed by PPL Services Corporation (“PPL Services”) as Vice President –
8 Transmission and Distribution Planning and Asset Management and provide services to PPL
9 Electric Utilities Corporation (“PPL Electric” or the “Company”).

11 **Q. Have you previously filed testimony in this matter?**

12 A. Yes.

14 **Q. What is the purpose of your rebuttal testimony?**

15 A. In my rebuttal testimony, I respond to portions of the direct testimony submitted by the
16 Pennsylvania Public Utility Commission’s (“Commission” or “PUC”) Bureau of
17 Investigation and Enforcement (“I&E”) Witnesses Walker and Tarr, Office of Consumer
18 Advocate (“OCA”) Witnesses Hoyt, Colton, and Wise, Office of Small Business Advocate
19 (“OSBA”) Witness Ewen, Coalition for Affordable Utility Services and Energy Efficiency in
20 Pennsylvania (“CAUSE-PA”) Witness Havumaki, Energy Justice Advocates (“EJA”)
21 Witness Rábago, Environmental Intervenors (“EI”) Witness Nelson, and PP&L Industrial
22 Customer Alliance (“PPLICA”) Witness LaConte. In particular, my rebuttal testimony

addresses issues pertaining to large load interconnections, the Company's electric service reliability and performance, and PPL Electric's storm restoration and planning.

Q. Are you sponsoring any exhibits or schedules as part of your rebuttal testimony?

A. Yes. Attached to my rebuttal testimony is PPL Electric Exhibit JL-1R [Answer to CAUSE-PA VIII-9 and CAUSE-PA VIII-9 Attachment 1].

II. LARGE LOAD INTERCONNECTION

Q. Do any of the parties provide comments or propose adjustments or recommendations related to the Company's reliability and performance?

A. Yes. OCA Witness Hoyt provides analysis, findings, and recommendations regarding large load interconnections. OCA Witness Colton also sets forth findings and recommendations regarding large load interconnections and affordability. OCA Witness Wise similarly offers testimony on the impacts of large load interconnections discussed during public input hearing held in this proceeding. Further, OSBA Witness Ewen provides testimony on the inclusion of new large load customers in the LP-5 rate class and on allocation of universal service charges to new large load customers. Meanwhile, CAUSE-PA Witness Havumaki offers recommendations regarding the Company's proposed treatment of new large load interconnections and its proposal to socialize transmission system costs associated with new large load customers. Additionally, EJA Witness Rábago provides recommendations on the Company's proposed LP-5 rate schedule revisions regarding cost allocation, and cost increases. Also, EI Witness Nelson makes recommendations regarding the Company's

1 proposed LP-5 rate schedule revisions. Lastly, PPLICA Witness LaConte likewise provides
2 recommendations regarding the Company's proposed LP-5 rate schedule revisions.

3
4 **Q. Do you have any initial thoughts on the other parties' positions regarding PPL Electric's**
5 **large load tariff proposal?**

6 A. Yes, I believe that the other parties are underestimating the potential for new large load
7 customers to create a win-win situation for existing customers. These new customers will fund
8 substantial investment in the Company's transmission system, which will make it more
9 reliable and resilient for all customers. At the same time these new large load customers will
10 shoulder a larger share of transmission costs meaning that existing customers will benefit from
11 an improved grid at lower cost. In real numbers, the Company is anticipating that a residential
12 customer with average monthly usage of 1,000 kWh will see their transmission costs go down
13 by approximately \$40/year with the first addition of 1 GW of load. If the Company
14 interconnects the projected 20 GW of load it is anticipating, existing residential customers
15 stand to see transmission costs be reduced by approximately \$255/year. (See PPL Electric
16 Exhibit JL-1R [Answer to CAUSE-PA VIII-9 and CAUSE-PA VIII-9 Attachment 1.] The
17 other parties have raised legitimate concerns regarding affordability impacts in the generation
18 and capacity markets. Although this proceeding is focused on distribution, the Company has
19 carefully considered these recommendations and revised its proposal to address these issues.

1 **Q. In preparing PPL Electric’s large load tariff provisions did you consider the model tariff**
2 **for large load interconnections proposed by the Commission?**

3 A. I have reviewed and considered it and assisted in preparing the Company’s comments
4 submitted at Docket No. M-2025-3054271. However, the Company submitted its base rate
5 case on September 30, 2025, prior to the PUC issuing its order on the model tariff on
6 November 6, 2025. My responses to the other parties’ witnesses will address many of the
7 topics raised in the model tariff now that the Company has the benefit of having reviewed it.

8
9 **Q. Do any of the other parties recommend creating a new rate class for large load**
10 **customers?**

11 A. Yes, OSBA Witness Ewen, CAUSE-PA Witness Havumaki, and PPLICA Witness LaConte
12 all recommend creating a separate rate for new large load customers. (OSBA St. No. 1, pp. 4,
13 16; CAUSE-PA St. No. 2, p. 21; PPLICA St. No. 1, pp. 4, 13-15.) The reasoning provided is
14 that new large load customers are fundamentally different than existing LP-5 customers, a
15 new rate class will allow the Company to assign costs to the new large load customers and
16 assign Universal Service costs to new large load customers.

17
18 **Q. Why did the Company not propose a new rate schedule for large load customers?**

19 A. The Company’s rate schedules are for distribution rates. LP-5 customers take service at or
20 above 69 kV. PPL Electric’s tariff defines its distribution system as facilities operating at
21 voltages below 69 kV. The LP-5 rate class only has a customer charge to cover certain fixed
22 costs associated with providing retail service to these customers. The costs of the distribution

1 system facilities are not allocated to LP-5 customers because LP-5 customers do not use or
2 benefit from the distribution system. Regardless of the size of the customer, all LP-5
3 customers are similarly situated for the purposes of *distribution* ratemaking.

4
5 **Q. Would the Company consider creating a new large load rate class?**

6 A. Yes, but it would not resolve all of the concerns that the other parties have. PPL Electric is
7 not opposed to creating a rate class for customers with peak demands in excess of 100 MW.
8 This would allow the Company to assign a portion of Universal Service costs to this rate class,
9 which I will discuss in additional detail later. However, the fact remains that no costs from
10 new large load customers will be allocated to other customers in their distribution rates with
11 or without this new rate class. Additionally, it will not allow for the direct assignment of
12 transmission costs to this new rate class. Transmission costs are allocated in accordance with
13 the Company's Federal Energy Regulatory Commission ("FERC") Formula Rate, which is
14 not affected by a customer's distribution rate classification.

15
16 **Q. How do you respond to the other parties' concerns about the impact to affordability
17 created by new large load customers?**

18 A. PPL Electric is also mindful of keeping rates affordable for customers. However, the
19 Company disagrees with the criticisms from the other parties. The new large load customers
20 do not have any impact on distribution rates, as the interconnection system upgrade costs are
21 recovered through transmission rates. Adding data centers and other large load customers to
22 the PPL Electric system will reduce transmission rates for existing customers. This leaves the

1 impact to affordability being caused by generation and capacity costs which PPL Electric has
2 no control over.

3
4 **Q. Does everyone agree that new large load customers do not impact distribution rates?**

5 A. No, specifically testimony at the Public Input Hearings, various customers and public officials
6 alleged that data center development is the principal driver behind the Company filing this
7 distribution base rate case. This is not true, and I will explain in greater detail below, none of
8 the costs to serve new large load customers are included in distribution rates.

9
10 **Q. Do they have similar concerns about transmission rates?**

11 A. The other parties' concerns with the Company's projections of transmission rate reductions
12 mostly involve challenging Company assumptions in its analysis. Specifically, they question
13 the Company's assumptions about the amount of additional load and the cost to interconnect
14 the new customers. I do not think these are fair criticisms as it is extremely likely that adding
15 new large load customers will have a downward pressure on transmission rates. PPL Electric's
16 transmission costs are allocated to customers based on their contribution to the Company's
17 system peak. The current system peak is approximately 7.5 GW. It is safe to assume that
18 adding a 1 GW large load customer will increase the system peak to 8.5 GW because the new
19 large load customers are expected to have stable continuous operations. This will result in this
20 one new customer being allocated approximately 12% of the Company's transmission
21 revenue requirement. The percentage being allocated to large load customers will only
22 increase as new customers are interconnected. It is true that the revenue requirement will

1 increase as upgrade costs are included in rate base. However, those increased costs will be
2 far outpaced by large load customers being allocated a substantial portion of transmission
3 rates which will have the effect of reducing transmission rates for other customers as I
4 explained earlier.

5
6 **Q. Can you explain the other parties' concerns about the impact of new large load**
7 **customers on the generation and capacity markets?**

8 A. Yes, the other parties explain that the generation markets are unable to add capacity to match
9 the new large load additions. This has created a supply and demand challenge, where supply
10 cannot meet demand, resulting in higher prices. PPL Electric agrees that new large load
11 additions are contributing to increases in generation and capacity costs. In fact, the Company
12 has advocated for legislative change to address the affordability challenges being created by
13 the generation markets. However, PPL Electric is a transmission and distribution company
14 and has no control over generation and capacity market costs as it operates in a restructured
15 state. See 66 Pa. C.S. §§ 2801, *et al.* Using transmission and distribution rates to address
16 concerns with generation markets runs afoul of cost of service principles and is bad public
17 policy. The other parties have legitimate concerns about the design of the generation and
18 capacity markets, but they should raise those concerns directly with the entities that are
19 responsible for those markets, just as PPL Electric has been raising its concerns.

20

1 **Q. Could the Company address generation and capacity costs issues with its default service**
2 **plan?**

3 A. Several of the parties point to the Company's increasing Price to Compare ("PTC") as
4 evidence of the impact of new large load customers are having on affordability. PPL Electric
5 has a Commission-approved Default Service Plan where it acquires generation supply for
6 customers that do not shop. The costs of acquiring that default service are passed through
7 directly to the customers using that service, and PPL Electric earns no mark-up or profit for
8 providing Default Service. The increases in the PTC are a result of the same supply and
9 demand dynamics I discussed above. The Company designed its Default Service Plan with
10 affordability and rate stability in mind. There is nothing PPL Electric can do in its Default
11 Service Plan to meaningfully address affordability until the underlying fundamentals of the
12 generation and capacity markets are addressed.

13
14 **Q. Did the other parties express any concerns about other customers being responsible for**
15 **the costs to interconnect new large load customers?**

16 A. Yes, and this was a theme of many of the parties' statements that addressed the proposed large
17 load provisions. Specifically, OCA Witness Hoyt, OCA Witness Colton, OCA Witness Wise,
18 CAUSE-PA Witness Havumaki, EJA Witness Rábago, EI Witness Nelson, PPLICA Witness
19 LaConte, and OSBA Witness Ewen all addressed their concerns about costs to interconnect
20 new large load customers being allocated to existing customers. (OCA St. 5, p. 42; OCA St.
21 8, pp. 88-93; OCA St. 9, pp. 8-15; CAUSE-PA St. No. 2, pp. 6-7; EJA St. No. 1 pp. 71-77;
22 EI St. No. 1, pp. 10-21; PPLICA St. No. 1, pp. 11-12; OSBA St. No. 1, pp. 15-16.)

1
2 **Q. Can you explain PPL Electric's policy on allocating costs associated with**
3 **interconnecting new large load customers?**

4 A. As an initial matter it is important to understand what costs are involved in interconnecting a
5 new large load customer. The new large load customers that are being discussed by the other
6 parties are LP-5 customers, or in other words, customers that are taking service at transmission
7 voltage levels. Any costs associated with interconnecting these new large load customers that
8 are socialized through rates will be recovered through the Company's FERC Formula Rate
9 and consistent with cost allocation principles described below. Interconnecting new large load
10 customers has almost no impact on distribution rates, which are the subject of this case.

11 When a new large load customer applies for service, the Company evaluates whether
12 the required upgrades only benefit the new customer, or if the upgrades would provide broader
13 grid benefits. Upgrades that only benefit the customer are directly charged to the customer
14 through a Contribution in Aid of Construction ("CIAC") payment. Upgrades that provide
15 broader grid benefits are recovered through the Company's FERC Formula Rate because all
16 customers benefit from the additional reliability benefits the upgrade provides. The
17 Company's policy is explained in greater detail in the Company's response to OCA VIII-9
18 and OCA VIII-9 Attachment 1. (See PPL Electric Exhibit JL-1R.)
19

1 **Q. Do the other parties have any concerns with Company’s current policy on cost allocation**
2 **of interconnection costs for new large load customers?**

3 A. Yes, their concerns are generally that new large load customers should pay for the entirety of
4 upgrades through CIAC, and that PPL Electric has too much discretion in determining which
5 costs are socialized under its current policy.

6
7 **Q. Do you agree with their concerns?**

8 A. No. PPL Electric is following FERC precedent in socializing network upgrades that benefit
9 other customers. The other parties’ recommendations are asking the PUC to exceed its
10 jurisdictional authority and dictate the terms of transmission ratemaking. Likewise, I disagree
11 that there is not appropriate oversight of PPL Electric’s decision to socialize certain
12 interconnection upgrade costs. The Company is subject to prudence and proper cost allocation
13 challenges at FERC with respect to its transmission investments. None of the parties have
14 provided any testimony as to why FERC’s oversight of PPL Electric’s transmission rates is
15 inadequate. Regardless, the other parties cannot confer jurisdiction over transmission rates to
16 the PUC simply because that would be their preference.

17
18 **Q. How do you respond to the other parties’ criticism that new large load customers are**
19 **not paying their fair share?**

20 A. I disagree with the criticism because it ignores how transmission costs are allocated. While a
21 portion of upgrades costs that provide benefit to all customers will be recovered through
22 transmission rates, the new large load customers will pay a significant portion of those

1 socialized upgrade costs. The Company's FERC Formula Rate is allocated to customers based
2 on their contribution to the PPL Electric system peak. Because the new large load customers
3 will have a high peak demand, they will also be allocated a significant portion of the
4 Company's revenue requirement for its transmission rate. There has been much criticism that
5 the LP-5 distribution customer charge is being reduced from \$994.00 to \$973.44. However,
6 what is being ignored in that criticism is that the hypothetical 1 GW large load customer would
7 be paying over \$100 million a year in transmission rates under current rates. This will in turn
8 lessen the amount of transmission costs to be recovered from other customers.

9
10 **Q. Do you have a response to EJA Witness Rábago's contention that large load customers**
11 **will put more costs on residential customers through the TSC (EJA St. No. 1, pp. 74-**
12 **75)?**

13 A. Yes, and it shows Mr. Rábago's lack of understanding of how PPL Electric's transmission
14 rates work. The Company's TSC is to recover transmission costs from customers who take
15 default service. However, the amount of costs recovered through the TSC is still based upon
16 the customer class contribution to the PPL Electric system peak. With the addition of new
17 large loads, the residential customer class will be responsible for a smaller percentage of the
18 Company's transmission revenue requirement which will lower transmission costs for all
19 existing customers, including the TSC for residential default service customers.

20

1 **Q. How do you respond to the concern that the new large loads are speculative, and the**
2 **load may not materialize?**

3 A. The Company proposed a minimum load guarantee that will cover the cost of socialized
4 upgrades to address any risk that load does not materialize as expected. The Electric Service
5 Agreement (“ESA”) makes sure that at a minimum the new large load customer will pay
6 transmission rates equal to the cost of the socialized upgrade.

7
8 **Q. Do the other parties have other concerns about the Company’s minimum load**
9 **guarantee proposal?**

10 A. Yes, there is general concern that the new large loads will be able to peak shave to avoid
11 paying transmission costs, that the minimum load guarantee security will not be used to
12 insulate other customers from risk, and that the minimum load guarantee will not cover the
13 entire cost of the socialized upgrades.

14
15 **Q. Do you agree with the peak shaving concern?**

16 A. No. The Company has designed its minimum load guarantee and standby charges to ensure
17 that new large load customers are paying their fair share for the transmission system. During
18 the guarantee period, the new large load customer will be paying 80% of their load ramp
19 schedule regardless of actual usage. In practice, this will mean that the customer’s peak
20 demand value will be at least 80% of the agreed upon load ramp schedule. The Company will
21 receive transmission revenue from the new large load customer until the guarantee obligation
22 is satisfied even if the customer has no actual usage.

1 PPL Electric has also proposed new standby charges in Rule 6 of the tariff to ensure
2 that customers with onsite generation are paying their fair share for reserve capacity. New
3 large load customers will be paying for 30% of the nameplate capacity of their onsite
4 generation to reserve capacity on the transmission system. I would note that, in my experience,
5 new large load customers are not interested in peak shaving, and given the size of the loads,
6 it would be impractical to reduce the entire amount of their load through peak shaving.
7 However, assuming that the hypothetical 1 GW customer has onsite generation to serve its
8 entire load, this customer would still be allocated transmission charges for 300 MW of peak
9 demand. For reference, a 300 MW customer would be approximately six times larger than the
10 Company's largest customer today. Again, this is a benefit with respect to all other customers'
11 transmission rates.

12
13 **Q. How will the Company utilize minimum load guarantee payments in the event of a**
14 **customer default?**

15 A. PPL Electric will credit the minimum load guarantee payments to transmission rate base,
16 which will lower the amount of rate base and in turn reduce the amount that the Company is
17 earning a rate of return on. OCA Witness Hoyt questions whether the Company would
18 actually reduce the amount of rate base when it receives a minimum load guarantee payment.
19 (OCA St. 5, pp. 42-43.) That has always been the Company's intent, and it is not opposed to
20 further clarifying this in the Retail Tariff as part of the Company's compliance filing.

21

1 **Q. How do you respond to the concern that the minimum load guarantee does not cover all**
2 **of the costs of the upgrades?**

3 A. Several of the witnesses allege that the minimum load guarantee only covers the cost of the
4 initial upgrade, but not the entire revenue requirement over the life of the asset. This may be
5 technically true, but the Company's proposal is still appropriate. The other parties assume that
6 the new large load customer's transmission revenue will only cover the cost of the new
7 upgrades. What is more likely is that once a new large load customer begins taking service it
8 will continue to take service for decades. Given how the FERC Formula Rate is allocated, it
9 is far more likely that the new large load customers will pay for the socialized upgrades several
10 times over. In the event that the new large load customer terminates early, the minimum load
11 guarantee will be used to lower rate base which will essentially have the effect of CIAC on
12 rates. The other parties are overstating the likelihood of new large load customers ceasing to
13 take service given the billions of dollars of investment these entities are making in their
14 facilities. The new large load customers are a win-win for other existing customers because
15 they will benefit from a more reliable transmission system and have lower transmission rates.

16
17 **Q. Mr. Hoyt cites PECO's TSA as having provisions that are more protective to other**
18 **customers. (OCA St. No. 5, pp. 43-44.) Do you agree with this conclusion?**

19 A. No, and the protections that Mr. Hoyt describes are almost identical to PPL Electric's current
20 ESA terms. PPL Electric has an 80% minimum load guarantee, termination payments, and a
21 periodic review of whether the customer is meeting load commitments. I would note that the
22 PECO agreement also contemplates socializing a portion of the interconnection upgrade,

1 which is why the agreement has termination payments.¹ Mr. Hoyt favorably references the
2 PECO agreement in comparison to PPL Electric's agreement despite the two agreements
3 being almost identical with respect to the terms and conditions to protect other customers from
4 the large load customer load not materializing.

5
6 **Q. How do you respond to the recommendation that new large load customers pay for the**
7 **entire cost of the required upgrades through CIAC (CAUSE-PA St. No. 2, p. 12)?**

8 A. I disagree with the recommendation. As a starting point, network upgrades, by their very
9 nature, benefit all customers. They add to system reliability, increase transmission capacity
10 and lower congestion, increase resiliency and operational flexibility, and expand capacity for
11 new generation flow and interconnection, among other things. In recognition of these system-
12 wide benefits, FERC has also long-favored charging network customers for costs of network
13 facilities without an individualized benefit calculation, stating that "due to the integrated
14 nature of the transmission network, network facilities benefit all network users," even if "the
15 facilities were installed to meet a particular customer's request for service" and that "there is
16 no need to identify further actual benefits in order to include the costs of network transmission
17 facilities in transmission rates."²

¹ See *Transmission Security Agreement Between PECO Energy Company and Amazon Data Services, Inc.*, FERC Docket No. ER25-03492-000, pp. 3-4, 10-12 (Filed Sep. 23, 2025).

² *City of Anaheim, Cal.*, 113 FERC ¶ 61,091, at P 58 (2005), reh'g denied, 114 FERC ¶ 61,311 (2006)

1 **Q. Have you considered the Commission’s Model Tariff provision that would require a new**
2 **large load customer to pay for upgrades through CIAC if they receive more than 50%**
3 **of the benefit?**

4 A. Yes, and I do not think it is a workable solution. The Commission’s proposed “more than half
5 the benefit of this line” provision, lacks the clarity and flexibility of PPL Electric’s approach.
6 It is unclear how electric distribution companies (“EDCs”) are even to calculate and measure
7 benefits of network upgrades to effectuate this provision. In transmission ratemaking, this is
8 a highly contentious and litigated topic. Although complex tools have been developed to
9 measure use of a transmission facility, they can only be implemented once the line is built and
10 flows can be measured. Even then, they change in real time—to say nothing about changes
11 over the decades of expected useful life of a transmission network facility. Finally, PPL
12 Electric has serious concerns about the Commission’s jurisdiction over this subject. Recovery
13 of investment in transmission network upgrades is a ratemaking question. For transmission
14 facilities, ratemaking is regulated by FERC, not by the Commission.

15
16 **Q. Does EI Witness Nelson’s recommendation resolve your concerns about the large load**
17 **customers paying for the entire upgrade costs through CIAC?**

18 A. No, if anything, Mr. Nelson’s recommendation confuses the issue even more. Generally,
19 Witness Nelson recommends that the customer pay for the upgrades through CIAC that will
20 then be reimbursed to the customer as they take service. (EI St. No. 1, pp. 18-19.) This
21 fundamentally misunderstands how CIAC works. CIAC is paid for upfront to cover the cost
22 of the capital investment. Because the cost is paid for by the customer, there is no increase to

1 rate base. Under Mr. Nelson's recommendation, rate base would need to be increased as the
2 CIAC was reimbursed to the customer. This defeats the entire purpose of having a customer
3 pay CIAC. For this reason, and the other reasons provided in my rebuttal testimony, I reject
4 Mr. Nelson's proposed redlines to the LP-5 rate schedule.

5
6 **Q. Several of the witnesses raise concerns about the lack of transparency in the process to**
7 **interconnect new large load customers, can you summarize their concerns?**

8 A. Yes, OCA Witness Hoyt, EJA Witness Rábago, EI Witness Nelson, and PPLICA Witness
9 LaConte all raise concerns about the transparency in the interconnection process. (OCA St, 5,
10 pp. 5, 52; EJA St. No. 1, pp. 69-70, 73-74; EI St. No. 1, pp. 12-13; PPLICA St. No. 1, p. 10.,
11 12-13.) They want the ESAs submitted for PUC review, a review of the allocation of
12 interconnection costs, and a prohibition on charging new large load customers special rates.
13 (OCA St. 5, pp. 8, 19; EJA St. No. 1, pp. 77-78; EI St. No. 1, pp. 5-6, 38-39; PPLICA St. No.
14 1, p. 13.)

15
16 **Q. What is the Company's position with respect to submitting ESAs for review, including**
17 **a review of the allocation of interconnection costs?**

18 A. The Company is not opposed to submitting ESAs for information. However, the review
19 should not include the ability for the Commission to review and reject the Company's
20 allocation of interconnection costs between the customer and rates. As I discussed earlier, the
21 determination of whether costs are properly included in transmission rates is a FERC

jurisdictional question. Any challenge of the Company's decision to include certain costs in transmission rates should be raised at FERC.

Q. Does the Company negotiate special rates with customers?

A. No, and all the ESAs with new large load customers state that the customer will be paying applicable tariff rates. The special terms are all for other customers' protection involving the minimum load guarantee and security provisions. PPL Electric cannot give any customer a preferential rate without receiving regulatory approval.

Q. Can you describe the other parties' concerns with the length of the term of the ESA?

A. Yes, there is general concern that the length of the ESA is not long enough, and that the minimum term should be between 10 and 20 years. The reasoning is that this will limit stranded asset risk on other customers. Additionally, they would like higher exit fees consistent with the Model Tariff proposal.

Q. Do you agree with these recommendations?

A. Not entirely. The Company's current proposal requires a minimum load guarantee until PPL Electric receives enough revenue to cover the cost of the initial cost of upgrades included in transmission rates. This accounts for the fact that utilities have an obligation to serve new load, and load growth is a legitimate need to address when upgrading its system. Covering the cost of the initial investment with a minimum load guarantee ensures that the investments in

1 serving new load are prudently made. This is consistent with how PPL Electric treats line
2 extensions at lower voltages.

3 That being said, the Company is not opposed to having a minimum 10-year term for
4 its large load ESAs. The minimum load guarantee would be 80% for the first five years, and
5 50% for the second five years. The customer would still provide security for the initial amount
6 of socialized investment, however there would be an additional exit fee equal to the amount
7 of the remaining minimum load guarantee. Proceeds from the exit fee would be used to reduce
8 the Company's transmission revenue requirement. This proposal will result in new large load
9 customers agreeing to take service in an amount that far exceeds the initial cost of upgrades
10 placed into transmission rates.

11
12 **Q. Do any of the parties raise concerns about the reliability impacts of interconnecting new**
13 **large load customers?**

14 A. Yes, OCA Witness Hoyt and CAUSE-PA Witness Havumaki raise concerns about reliability
15 impacts from new large load interconnections. (OCA St. No. 5, pp. 44-50; CAUSE-PA St.
16 No. 2, pp. 9-10.) There is passing mention of the impacts to the reliability of the transmission
17 system, but the majority of their concern is about whether there will be enough generation
18 capacity to serve the new load.

19
20 **Q. Do you agree with their concerns?**

21 A. With respect to the transmission system, the answer is no. The Company studies each
22 interconnection application to ensure that the new customer can safely and reliably

1 interconnect to PPL Electric's grid. I do understand their concerns regarding generation
2 resource adequacy associated with interconnecting these new loads. However, I disagree that
3 PPL Electric distribution base rate case is the appropriate forum to address generation and
4 capacity resource adequacy concerns. I am advised by counsel that PPL Electric has an
5 obligation to serve all customers in a non-discriminatory manner. Additionally, the
6 Competition Act requires EDCs to allow customers to have open access to competitive
7 generation markets. Regardless of the merits of Mr. Hoyt and Mr. Havumaki's
8 recommendation, the Company is without authority to turn customers away because of a lack
9 of generation capacity. The appropriate venues to address these concerns are at FERC, and
10 with the Pennsylvania General Assembly should the parties want to advocate for changes to
11 the Competition Act.

12
13 **Q. Would reliability concerns be resolved through Mr. Rábago's recommendation that the**
14 **Company be required to use grid enhancing technologies (EJA St. No. 1, p. 79)?**

15 A. Not entirely, and to be clear, PPL Electric is an industry leader in utilizing grid enhancing
16 technologies. It was one of the first utilities to utilize dynamic line ratings ("DLR") on its
17 transmission lines and has deployed this technology on 8 lines in Pennsylvania as of January
18 21, 2026. However, grid enhancing technologies seek to maximize existing assets. They
19 cannot eliminate the need for new generation to meet current and projected load growth in
20 PJM.. Additionally, grid enhancing technologies cannot eliminate having to build
21 transmission facilities to interconnect and serve the new customers.

1 **Q. Do you have any response to Mr. Rábago’s recommendation that new large load**
2 **customers be required to bring their own generation (“BYOG”) and that a portion of it**
3 **be renewables? (EJA St. No. 1, p. 79.)**

4 A. I have the same concerns that I have with conditioning the interconnection of a new customer
5 on PUC approval that there is adequate generation capacity to serve the customer. This
6 recommendation is inconsistent with PPL Electric’s obligation to provide non-discriminatory
7 delivery service to all of its customers. It is not the EDC’s role to assess the adequacy of
8 generation resources available within PJM or to specify how any single customer sources its
9 generation needs. Again, I would remind Mr. Rábago and other parties that the Competition
10 Act of 1996 deregulated generation in Pennsylvania and set forth the obligations of EDCs to
11 serve retail customers.

12
13 **Q. Mr. Hoyt and Mr. Rábago recommend that new large load customers take service under**
14 **a mandatory requirement that their load be interruptible. (OCA St. 5, p. 49; EJA St.**
15 **No. 1, p. 79.) Do you agree?**

16 A. No, and I come back to the Company’s obligation to provide non-discriminatory service. I
17 disagree that the Company has the authority to single out a type of customer based on their
18 end use of the service and treat them differently. However, PPL Electric is willing to provide
19 a voluntary interruptible option in its tariff that would allow the Company to curtail certain
20 customers during times of system stress. To incent customers to choose this option, the
21 Company would reduce the minimum load guarantee percentage to 60% for the first five
22 years, and to 30% for the second five years under the ESA. A customer with interruptible

1 service would be less likely to create the ancillary costs that the other parties are concerned
2 about which justifies the lower minimum load guarantee percentage.

3
4 **Q. Did the other parties have any concerns about PPL Electric's load forecasting process?**

5 A. Yes, Mr. Hoyt and Mr. Nelson criticized the Company's current load forecasting procedures.
6 Generally, their concerns are that the Company is inflating its load projections by including
7 projects at the Letter Of Authorization ("LOA") stage, not being transparent with its forecasts,
8 and not performing enough diligence on whether the projects are duplicative. (OCA St. 5, pp.
9 50-51; EI St. No. 1, pp. 39-45.)

10
11 **Q. Do you agree with this criticism?**

12 A. No. The Company endeavors to be transparent with its load forecast so that those responsible
13 for ensuring resource adequacy have information in time to take appropriate action. The other
14 parties point out the risk of inflating a load forecast, but they fail to consider the risks of
15 underestimating load growth. If the load does materialize and adequate market signals have
16 not been sent for new generation to be built, the price shock for capacity will likely be similar
17 to an overestimate. The Company's goal has always been to provide accurate load forecast
18 information so that the market has enough time to respond to have generation ready to serve
19 this new load.

20

1 **Q. Does PJM reducing the Company’s load forecast demonstrate that the process is**
2 **flawed?**

3 A. No, the Company is providing information to PJM, and it is PJM’s discretion on how they
4 want to use the information. Although PPL Electric is ultimately not responsible for ensuring
5 resource adequacy, the Company is providing PJM with information to make informed
6 decisions. I do not know why PJM reduced PPL Electric’s load forecast or if it was advisable
7 to do so, but it cannot be said that the Company was avoiding being transparent.

8
9 **Q. Will Non-Disclosure Agreements (“NDAs”) prevent the Company from sharing**
10 **accurate load forecasts?**

11 A. No. The Company is willing to share ESAs and load growth forecasts with its regulators with
12 proper confidentiality protections in place. In fact, it has shared several ESAs during discovery
13 in this case. These ESAs have also included customer load ramping schedules. The need for
14 the NDAs is to protect the proprietary confidential information of our customers on the size
15 and timing of the development of their projects. PPL Electric has nothing to hide.

16
17 **Q. Does the Company oppose sharing load forecasts with the PUC?**

18 A. No, and recent legislation has required EDCs to share load forecast information with the PUC.
19 PPL Electric has no issue with sharing load forecast information with regulators and
20 stakeholders broken down by new load under an ESA, under an LOA, and load that has made
21 inquiries. In this way regulators and stakeholders will have adequate information to make
22 decisions.

1
2 **Q. Will this information include the more detailed information on the status of the new**
3 **large load development such as site control and permitting?**

4 A. PPL Electric is not opposed to sharing site control and permitting information to the extent
5 that it has it from customers. This information would need to be shared confidentially as it
6 contains proprietary information from customers.

7
8 **Q. How do you respond to the allegation that the Company is inflating load growth**
9 **projections because it financially benefits from it (EI St. No. 1, p. 40)?**

10 A. I strongly disagree with this suggestion. It is generally true that load growth provides system
11 upgrade opportunities for the Company. That does not mean that it is gaming the system by
12 inflating its load forecasts. As I stated earlier, the Company is willing to provide a range of
13 information on load forecasts so that regulators and stakeholders can make informed
14 decisions. This voluntary transparency undercuts any argument that PPL Electric is
15 manipulating load forecasts for financial benefit.

16
17 **Q. Do other parties recommend that the Commission require new large load customers to**
18 **contribute to PPL Electric's universal service costs?**

19 A. Yes, OCA Witness Colton, OSBA Witness Ewen, and CAUSE-PA Witness Havumaki all
20 recommend that new large load customers contribute to the Company's Universal Service
21 Rider ("USR"). (OCA St. 8, p. 96; OSBA St. No. 1, pp. 17-19; CAUSE-PA St. No. 2, pp. 20,
22 25.) The reasoning provided is that, in their opinion, new large load customers will cause

1 affordability issues, which will increase the number of customers enrolling in universal
2 service programs. Mr. Colton takes it one step further and recommends a non-bypassable
3 systems benefit charge to assist customers who are not eligible for universal service programs.
4 (OCA St. 8, pp. 6, 87-88.)
5

6 **Q. Do you agree with the recommendations?**

7 A. Not completely. The Company did not propose large load customers contributing to the USR
8 because historically only residential customers paid for the USR. Under cost of service
9 principles, residential customers were allocated the entire cost of the universal service
10 programs because only residential customers can take advantage of those programs. However,
11 the Commission has since indicated in the Model Tariff proceeding that allocating a portion
12 of USR costs to large load customers is appropriate. The Company is not opposed to
13 allocating \$10 million of USR costs to the newly created LP-6 rate class. The Company agrees
14 to establish an LP-6 rate class and allocate \$10 million of the total projected USR costs to that
15 rate class effective January 1, 2027. The Company will establish a customer charge to recover
16 these costs from the LP-6 rate class. Further, the Company proposes to change the USR rate
17 filing from once per year in January to three times per year in January, May, and September.
18 This will provide an opportunity to update the LP-6 rate and spread the costs to newly
19 connected LP-6 customers. The Company will provide a revised Universal Service Rider
20 Tariff schedule in its compliance filing.
21

1 **Q. Do you have a response to OSBA Witness Ewen’s recommendation that large load**
2 **customers make a one time “CIAC” payment towards universal service costs (OSBA St.**
3 **No. 1, p. 18)?**

4 A. Yes, and initially I disagree that the payment would be in the form of CIAC. CIAC payments
5 are customer payments towards capital construction projects. This would be a one-time
6 payment towards a customer assistance program. That being said, the Company’s proposal of
7 allocating \$10 million to the new LP-6 class is a superior proposal, as it will provide
8 continuous, stable funding to universal service program costs, rather than variable one-time
9 payments that could cause USR rate volatility.

11 **Q. Do you have any additional thoughts on Mr. Colton’s non-bypassable charge**
12 **recommendation?**

13 A. Yes, I believe it is completely inappropriate. What Mr. Colton is alleging, without directly
14 saying it, is that current cost allocation policies are inadequate to assign costs to new large
15 load customers. I disagree with this suggestion that costs are allocated improperly, and new
16 large load customers will not pay for their fair share of their use of the grid. However, if Mr.
17 Colton wants to challenge cost allocation policies, then it is more appropriate to address these
18 policies directly in the design of the rates impacted rather than creating a mechanism to sit on
19 top of previously approved rates.

1 **Q. Were there any recommendations regarding the Company’s proposal to have the option**
2 **to own, operate, and maintain LP-5 customer substations?**

3 A. Yes, and they are opposed to the Company’s proposal on the grounds that it creates the
4 potential to allocate these costs to the other customers, and that there is the potential for abuse.

6 **Q. How do you respond to these concerns?**

7 A. These concerns are unfounded. PPL Electric’s proposal involves directly assigning these costs
8 to the customer taking service from the substation. There will be no recovery from other
9 customers. This is the same type of direct assignment these witnesses have advocated for in
10 the recovery of system upgrade costs for interconnections. The Company’s proposal should
11 be approved because there has not been any showing that it will involve any cross-
12 subsidization with other customers.

14 **Q. Did any of the parties raise concerns regarding PPL Corporation’s joint venture with**
15 **Blackstone?**

16 A. Yes, OCA Witness Hoyt and EI Witness Nelson recommended additional protections
17 regarding PPL Electric’s dealings with the joint venture. They raised concerns about conflicts
18 of interest, and the incentive to socialize costs to the benefit of the affiliate joint venture. (OCA
19 St. 5, pp. 54-55; EI St. No. 1, pp. 47-49.)

1 **Q. Are these concerns valid?**

2 A. No. The Company has robust internal affiliate transaction protections as described in Bethany
3 Johnson's rebuttal testimony (PPL Electric St. No. 5-R). Additionally, any affiliate agreement
4 between PPL Electric and the joint venture would require PUC approval. That would be the
5 time to evaluate the transaction rather than speculating on what a future transaction may look
6 like and placing restrictions on it today. Finally, PPL Electric would be required to serve the
7 joint venture under its Commission-approved tariff, which adds another layer of protection.

8
9 **Q. Did any of the parties raise concerns about the environmental impacts of new large load**
10 **customers?**

11 A. Yes, several witnesses at the public input hearings and other parties expressed concerns about
12 the environmental impacts of data centers. These concerns ranged from the impact on water
13 resources, land use policy, and air and noise pollution concerns.

14
15 **Q. Do you have a response regarding these environmental concerns?**

16 A. Yes, in that there are more appropriate venues to address these concerns outside of an EDC's
17 distribution base rate case. There are federal, state and local government agencies with
18 jurisdiction over the environmental issues raised by the other parties. There is also a full
19 regulatory and permitting regime designed to deal with the environmental impacts of
20 industrial development. It is through those processes that these environmental concerns should
21 be addressed, not in PPL Electric's base rate proceeding.

22

1 **Q. Can you summarize the changes PPL Electric is willing to make to its large load**
2 **provisions in its tariff in response to the other parties' testimony?**

3 A. Yes, PPL Electric is willing to make the following changes:

- 4 • Create a new LP-6 rate class for customers with peak demands of 75 MW and
5 above;
- 6 • 10 year minimum term for ESAs;
- 7 • Revise minimum load guarantee to 80% for first five years, 50% for second five
8 years of initial term;
- 9 • Exit fee equal to the remaining minimum load guarantee obligation during the ESA
10 term;
- 11 • PPL Electric will submit ESAs, CSAs, and a breakdown of the allocation of system
12 upgrade costs to the PUC for transparency and information (not approval);
- 13 • Offer a voluntary interruptible option, which if chosen would reduce the minimum
14 load guarantee to 60% for the first five years, and 30% for the second five years;
- 15 • PPL Electric will submit annual load forecasts to the PUC including a breakdown
16 of requests of customers with ESAs, LOAs, and inquiries; and
- 17 • LP-6 rate class will be allocated \$10 million of USR costs annually with the \$10
18 million to be allocated amongst the class.

1 **III. RELIABILITY AND PERFORMANCE**

2 **Q. Do any of the parties provide comments or propose adjustments or recommendations**
3 **related to the Company's reliability and performance?**

4 A. Yes. Mr. Tarr provides comments regarding wildfire preparedness. Also, Mr. Hoyt sets forth
5 analysis, findings, and recommendations regarding the Company's reliability performance.
6 Ms. Wise also offers testimony on the Company's reliability performance as discussed during
7 the public input hearings held in this proceeding.

8
9 **Q. Does Mr. Tarr make any claims with respect to the Company's wildfire preparedness?**

10 A. Yes. Mr. Tarr claims that the Company "has not conducted community outreach to educate
11 agencies, customers, and property owners about wildfires mitigation to reduce wildfire risk."
12 (I&E St. No. 5, p. 6.) He recommends that the Company initiate outreach to inform
13 communities about the risk of and preparing for wildfires so that local communities and first
14 responders will be better informed at identifying wildfire hazards and mitigation priorities,
15 and at taking action to reduce those risks. (I&E St. No. 5, p. 7.)

16
17 **Q. Do you agree with this recommendation?**

18 A. I agree that wildfire prevention is important. This is why PPL Electric has a wildfire
19 prevention program that focuses on reducing ignition risk and ensuring public safety through
20 proactive vegetation management and operational readiness. The Company maintains
21 transmission and distribution rights-of-way using tree pruning, hazard tree removal, brush
22 control, and herbicide application on a five-to-eight-year cycle, prioritizing high-risk areas. It

1 conducts wildfire mitigation drills that include modules on how to interact with first
2 responders. Internal teams validate emergency protocols, including activation for Red Flag
3 Warnings, and emphasize coordination across departments. These measures aim to minimize
4 wildfire hazards without relying on Public Safety Power Shutoff programs during storm or
5 fire events.

6 The Company is always looking for ways to improve, and it can take into
7 consideration whether proactive communication with community partners will improve its
8 wildfire response. PPL Electric has existing strong relationships with first responders in its
9 service territory and routinely coordinates with them in responding to emergencies that
10 involve the Company's facilities. During the Blue Mountain (2024) and Jim Thorpe (2025)
11 wildfire events, PPL Electric proactively provided safety information to the surrounding
12 communities and directly notified customers who were at risk of, or would be impacted by,
13 temporary service interruptions. In addition, the Company has incorporated wildfire safety
14 messaging into its rotating public-safety communications during high-risk seasons.

15
16 **Q. Does Mr. Hoyt provide any testimony regarding the reliability of the Company's**
17 **service?**

18 A. Yes. Mr. Hoyt states that the Company "is not currently meeting most of the Commission-
19 ordered targets for reliability, and its reliability scores for major metrics have [worsened] in
20 recent years." (OCA St. 5, p. 62.) After excluding 2024 metrics that he acknowledges are
21 attributable to major storms, he argues that the Company's reliability has worsened from

1 2015-present and that PPL Electric is not performing at the level of its peers. (*See* OCA St. 5,
2 pp. 62-74.)

3
4 **Q. Do you agree with Mr. Hoyt’s testimony regarding the reliability of the Company’s**
5 **service?**

6 A. No, I do not.

7
8 **Q. Why not?**

9 A. As an initial matter, I have three general points I want to raise regarding Mr. Hoyt’s testimony,
10 which provide important context regarding its reliability performance. First, Mr. Hoyt ignores
11 the fact that PPL Electric generally performs well relative to its peers with respect to Institute
12 of Electrical and Electronics Engineers (“IEEE”) Annual Reliability Benchmarking Survey
13 as well as the Edison Electric Institute (“EEI”) Reliability Survey, each of which I discuss in
14 detail in my direct testimony. (PPL Electric St. No. 16, pp. 2-5.) While he attempts to focus
15 on year-to-year variances and patterns in the Company’s System Average Interruption
16 Frequency Index (“SAIFI”), System Average Interruption Duration Index (“SAIDI”), and
17 Customer Average Interruption Duration Index (“CAIDI”) scores relative to its peers, he does
18 not actually offer any evidence that suggests PPL Electric does not perform better than its
19 peers. (OCA St. 5, pp. 71-74.) This is because the evidence demonstrates that while PPL
20 Electric’s metrics may experience year-to-year variances that are comparable to its peers, each
21 year it generally outperforms each peer with respect to each of IEEE and PUC SAIFI, SAIDI,
22 and CAIDI.

1 Second, Mr. Hoyt concedes that storm frequency and severity is an external factor
2 affecting the Company's reliability performance metrics, which the Company cannot control.
3 He acknowledges but does not dispute the Company's evidence that "both reportable and non-
4 reportable storm events have increased materially, with the Company experiencing an average
5 of approximately 40 storm events per year in recent years, compared to a historical average
6 of 23.6 events per year in the prior decade," (OCA St. 5, p. 75) and "agree[s] that severe
7 weather and vegetation conditions can materially affect reliability outcomes, and that major
8 storm activity can increase both the frequency and duration of outages." (OCA St. 5, p. 76.)
9 In addition, Mr. Hoyt attempts to justify his review of the Company's reliability performance
10 by, in part, excluding 2024 data in recognition of the fact that a record number of storms
11 occurred during this period. The Company has seen, and continues to see, an increase in the
12 frequency and severity of storms impacting its territory. Mr. Hoyt concedes this point by
13 excluding 2024 data, which is only half of the picture. (See OCA St. 5, p. 70 (arguing trends
14 in reliability performance are only "partially attributable" to 2024 storms).) The increased
15 frequency and severity of storms experienced by the Company justify the need for rate relief
16 and for the Company to increase its investments to strengthen and harden the system and to
17 increase vegetation management efforts. Without such investments, the Company's
18 reliability performance could continue to degrade.

19 Third, Mr. Hoyt ignores the fact that each of the Pennsylvania peers he compares PPL
20 Electric to in his analysis, has sought and obtained at least one base rate increase since 2015,
21 if not more. PPL Electric has not. While every utility's service territory and facilities differ,
22 and each utility is best positioned to determine how to maintain and enhance the reliability of

its system, the fact that PPL Electric has maintained reasonable reliability performance metrics that generally outperform its peers since 2015 despite having not sought a base rate increase since that time, further demonstrates that the Company manages the reliability of its system well.

Q. Please respond to Mr. Hoyt’s claim that the Company is not currently meeting most of its Commission-ordered reliability targets. (OCA St. No. 5, p. 74.)

A. PPL Electric has met the Commission’s SAIFI goal 10 out of 11 times between 2015 and 2025. The Commission’s SAIDI goal has been met 6 of 11 times, and the Commission’s CAIDI goal 3 of 11 times. Table 1 below illustrates this concept.

Table 1. PPL Electric’s Reliability Performance as Compared to the Commission’s Reliability Performance Targets

YEAR	PUC NON STORM SAIFI	PUC STORM SAIFI	PUC TOTAL SAIFI	PUC NON STORM SAIDI	PUC STORM SAIDI	PUC TOTAL SAIDI	PUC NON STORM CAIDI	PUC STORM CAIDI	PUC TOTAL CAIDI	PUC SAIFI GOAL	IEE SAIDI GOAL	PUC CAIDI GOAL	PUC Major Events	PUC Storms	Total Storms
2015	0.599	0.119	0.718	63.5	20.2	83.7	106.0	169.2	116.6	0.98	143	145	0	1	20
2016	0.589	0.188	0.776	55.3	38.7	94.0	94.0	206.0	121.1	0.98	143	145	0	4	24
2017	0.530	0.182	0.712	53.4	50.3	103.7	100.9	275.8	145.6	0.98	143	145	0	10	26
2018	0.631	0.215	0.845	63.7	77.8	141.5	101.0	362.2	167.4	0.98	143	145	1	5	23
2019	0.564	0.287	0.850	57.5	92.2	149.7	102.1	321.6	176.1	0.98	143	145	0	10	26
2020	0.522	0.320	0.843	47.0	68.7	115.7	90.0	214.4	137.3	0.98	143	145	0	8	27
2021	0.480	0.426	0.906	47.1	122.7	169.8	98.0	288.2	187.4	0.98	143	145	0	15	42
2022	0.511	0.355	0.866	54.0	88.1	142.2	105.7	248.5	164.2	0.98	143	145	0	9	36
2023	0.419	0.361	0.780	46.6	100.7	147.3	111.2	278.5	188.7	0.98	143	145	0	14	45
2024	0.473	0.746	1.219	55.8	395.8	451.6	117.8	530.8	370.4	0.98	143	145	0	17	37
2025	0.445	0.474	0.918	53.0	137.8	190.8	119.2	291.0	207.8	0.98	143	145	0	14	53

With recent high storm severity, along with automated systems preventing and converting outages to momentary interruptions, higher CAIDI values are not unexpected. During the benchmark period of 1994 to 1998, PPL Electric averaged 4.2 reportable events per year. From 2021 to 2025, under the same reporting standards, PPL Electric has averaged 13.8 reportable events per year, over triple the benchmark rate despite over one million customer interruptions avoided by automation during that time. Further, *prior* to the implementation of

1 automated restoration, every storm event of 1,000 or more cases was excludable as a PUC
2 Major Event with one exception (a flooding event). *Since* automated restoration, only 1 of 13
3 storms of over 1,000 cases have been excludable, and that storm reached 2,796 cases.

4 The combination of triple the reportable storm volume and near impossibility of
5 excluding storms as major events under the benchmarks established in the 1990s have made
6 the Company's ability to achieve its PUC targets increasingly challenging.

7
8 **Q. Please address OCA Witness Hoyt's claim that the Company has performed worse than**
9 **Pennsylvania peers in recent years. (OCA St. No. 5, p. 74.)**

10 A. Mr. Hoyt specifically only provides a detailed comparison of the Company's comparison to
11 other Pennsylvania utilities using one metric: CAIDI including Major Event Days ("MED").
12 (OCA St. No. 5, p. 73.) However, if additional reliability performance metrics are evaluated
13 in a manner similar to Witness Hoyt's evaluation of CAIDI, then the results provide a more
14 complete image of the Company's consistent above-average reliability performance. Table 2
15 below shows PPL Electric's reliability performance using six different metrics:

- 16 • SAIDI with MEDs
- 17 • SAIFI with MEDs
- 18 • CAIDI with MEDs
- 19 • SAIDI without MEDs
- 20 • SAIFI without MEDs
- 21 • CAIDI without MEDs

22 In addition, Table 2 was developed using EIA form 861 data, i.e., the same data
23 relied upon by Mr. Hoyt, pulled from the following peer companies of PPL Electric:

- 24 • Metropolitan Edison Co
- 25 • PECO Energy Co

- Pennsylvania Electric Co
- Pennsylvania Power Co
- UGI Utilities, Inc
- West Penn Power Company³

Using the six reliability metrics, as well as data from the years 2015 through 2024 enabled the Company to provide 60 points of comparison in Table 2. And, as shown below, PPL Electric ranks above average in 50 of the 60 comparisons (83.3%).

Table 2. Comparison of PPL Electric's Reliability Performance to Peer Utility Reliability Performance from 2015-2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SAIDI WITH MEDS	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Below Avg
SAIFI WITH MEDS	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg
CAIDI WITH MEDS	Above Avg	Below Avg	Below Avg	Below Avg	Above Avg	Above Avg	Below Avg	Above Avg	Above Avg	Below Avg
SAIDI WITHOUT MEDS	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg
SAIFI WITHOUT MEDS	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg
CAIDI WITHOUT MEDS	Below Avg	Above Avg	Above Avg	Above Avg	Above Avg	Above Avg	Below Avg	Above Avg	Below Avg	Below Avg

	COUNT	PCT
Above Avg	50	83.3%
Below Avg	10	16.7%

Moreover, Table 3 below provides a comparison of each peer utility's average performance across the ten-year period from 2015 to 2024. In each metric, the Company is ranked #1 or #2 in 5 out of 6 metrics and is above average in all 6 of the metrics.

Table 3. Comparison of PPL Electric's Average Reliability Performance to Peer Utility Average Reliability Performance from 2015-2024

	Average of SAIDI WITH MEDS	Average of SAIFI WITH MEDS	Average of CAIDI WITH MEDS	Average of SAIDI WITHOUT MEDS	Average of SAIFI WITHOUT MEDS	Average of CAIDI WITHOUT MEDS
Metropolitan Edison Co	396	1.58	236	173	1.28	135
PECO Energy Co	254	1.07	215	78	0.80	98
Pennsylvania Electric Co	340	1.93	174	213	1.63	131
Pennsylvania Power Co	290	1.36	206	129	1.08	120
PPL Electric Utilities Corp	191	0.90	201	80	0.67	119
UGI Utilities, Inc	138	0.85	152	104	0.76	131
West Penn Power Company	320	1.43	220	170	1.16	146
PPL Electric Rank	2	2	3	2	1	2

³ Note that complete EIA form 861 data was not available for Duquesne Light Company or for Pike County Light & Power Company and, as such, data from those peer companies was not used to develop the comparison in Table 1.

See Table 4 below for additional information regarding Internal IEEE goals (“benchmarks”) from 2015-2025:

YEAR	IEEE NON STORM SAIFI	IEEE STORM SAIFI	IEEE TOTAL SAIFI	IEEE NON STORM SAIDI	IEEE STORM SAIDI	IEEE TOTAL SAIDI	IEEE NON STORM CAIDI	IEEE STORM CAIDI	IEEE TOTAL CAIDI	IEEE SAIFI GOAL	IEEE SAIDI GOAL	IEEE CAIDI GOAL	PUC Major Events	PUC Storms	Total Storms
2015	0.597	0.075	0.672	62.6	12.5	75.2	104.9	167.7	111.8	0.79	87.0	110.1	0	1	20
2016	0.593	0.105	0.698	55.0	16.1	71.1	92.8	153.8	102.0	0.70	75.5	107.9	0	4	24
2017	0.515	0.089	0.604	50.6	19.4	70.0	98.3	218.9	116.1	0.68	69.4	102.1	0	10	26
2018	0.644	0.093	0.736	64.9	17.6	82.5	100.8	190.4	112.1	0.62	65.7	106.0	1	5	23
2019	0.571	0.089	0.661	56.8	17.5	74.3	99.4	196.0	112.5	0.65	68.3	105.1	0	10	26
2020	0.545	0.144	0.689	49.0	19.6	68.6	89.9	136.3	99.6	0.65	70.2	108.0	0	8	27
2021	0.494	0.189	0.683	48.6	35.8	84.4	98.4	189.8	123.6	0.65	68.9	106.0	0	15	42
2022	0.532	0.207	0.738	55.9	33.5	89.3	105.1	161.9	121.0	0.65	71.0	109.2	0	9	36
2023	0.434	0.208	0.643	47.6	43.9	91.5	109.5	211.0	142.4	0.65	71.0	109.2	0	14	45
2024	0.487	0.175	0.662	53.1	37.3	90.3	109.0	213.0	136.5	0.65	75.0	115.4	0	17	37
2025	0.490	0.275	0.765	59.1	56.9	116.0	120.7	206.9	151.7	0.68	75.0	115.4	0	14	53

Q. What is your response to Mr. Hoyt’s claim that while some reliability targets were met, the Company “did not provide sufficient information for Mr. Hoyt to evaluate performance consistency over time” (OCA St. 5, p. 74)?

A. I disagree that Mr. Hoyt did not have enough information to evaluate PPL Electric’s reliability performance over time. The data that I have relied on in my rebuttal testimony was available to Mr. Hoyt in utilities’ quarterly reliability reports as well as the PUC’s Annual Reliability Report.

Q. How do you respond to Mr. Hoyt’s argument that PPL Electric’s reliability outcomes have worsened over the past 10 years (OCA St. 5, p. 74)?

A. The Company acknowledges that there is room to improve its reliability performance, and to strengthen and harden the system against severe weather events. This is one of the primary drivers for rate relief in this case.

1 **Q. Do you agree with Mr. Hoyt’s further reporting and “accountability” requirements that**
2 **he believes the Commission should impose as a condition of recovery of the Company’s**
3 **proposed reliability investments and its base rate increase (OCA St. 5, pp. 62-63, 76-77)?**

4 **A.** Generally, I do not agree for several reasons.

5 First, it appears that Mr. Hoyt is advocating for the implementation of a form of
6 performance-based rates, by recommending that the Company’s investments be subject to a
7 “heightened prudence review” and “potential disallowance” in its next rate case or an interim
8 proceeding. (OCA St. 5, p. 77.) I am advised by counsel there are legal issues with his
9 proposal that PPL Electric will fully address this issue in any briefs submitted in this
10 proceeding.

11 Second, OCA Witness Hoyt appears to be attempting to establish a new standard for
12 assessing the prudence of the Company’s investments based upon the application of hindsight
13 and review of specific investments’ subsequent impacts on system reliability. Mr. Hoyt is
14 trying to compare very specific, localized capital projects with system-wide reliability metrics,
15 but those metrics operate on completely different scales. Because of that mismatch, his
16 analysis does not show what he claims it does. From the Company’s perspective, application
17 of this analysis as a means of assessing prudence has little value and creates a host of other
18 problematic issues. I am advised by counsel that PPL Electric will fully address this issue in
19 any briefs submitted in this proceeding.

20 Third, the additional reliability reporting proposed by Mr. Hoyt exceeds that which
21 the Commission already requires and PPL Electric already provides, and specifically seeks a
22 level of granularity of information that would require significant amount of additional labor

1 cost and/or significant costs related to IT improvements or modifications/significant changes
2 in the platforms PPL Electric uses to collect data. Mr. Hoyt provides no evidence of additional
3 benefits that would outweigh or justify the incurrence of these additional costs to implement
4 his recommendation.

5
6 **Q. Does Mr. Hoyt make any other findings based on his evaluation of the Company's**
7 **reliability?**

8 A. Yes. Mr. Hoyt analyzed outage events and reliability metrics from 2015 onward, comparing
9 them to the Company's capital investments in various work categories. Mr. Hoyt concluded
10 that these investments show "mixed and uneven results," with the impact on reliability varying
11 significantly depending on the type and timing of the investment. (OCA St. 5, pp. 62, 90-91.)

12
13 **Q. Do you agree with Mr. Hoyt's review of the Company's capital investments and**
14 **reliability performance and/or the conclusions he draws from his review?**

15 A. No, I do not.

16
17 **Q. Why not?**

18 A. While I note that in some circumstances OCA Witness Hoyt does purport to draw favorable
19 (and even strongly favorable) correlations between certain types of expenditures and
20 reliability, there are several general reasons why I do not believe this analysis can be relied
21 upon to draw conclusions regarding the relationship between annual levels of investment and
22 reliability metrics.

1 First, I question whether this methodology is theoretically sound. Mr. Hoyt is
2 attempting to correlate (a) annualized levels of investment related to specific types of projects
3 that are implemented on specific parts of the PPL Electric system throughout the year, with
4 (b) annual system-wide outage data and performance metrics. This is not an apples-to-apples
5 comparison as PPL Electric's annual capital investments do not touch upon its entire system
6 every year, whereas the metrics Mr. Hoyt reviews (i.e., SAIFI, SAIDI, CAIDI, MAIFI, and
7 CEMI) are based upon the entire system's performance in a given year. A more appropriate
8 comparison would be to conduct an analysis of the impacts of specific projects in each
9 category to improve the reliability of service for the customers most directly impacted by
10 those projects.

11 Second, Mr. Hoyt ignores variables that can impact the attempt to draw the
12 correlations he advances. For example, the following variables can impact this correlation:

- 13 1. **Variation of Realized Project Reliability Impact:** As stated in the Company's
14 response to Witness Hoyt's question regarding projects with delayed and non-delayed
15 reliability benefits, a project's impact on annualized reliability is not consistent upon
16 their completion.
- 17 2. **Safe Construction Methods:** Certain projects require scheduled outages to safely
18 construct, thus reducing reliability in that timeframe.
- 19 3. **Unexpected Variations Investment Plan:** The Company must fluidly balance both
20 proactive and reactive reliability projects to effectively maintain a safe and reliable
21 transmission and distribution grid.

1 Third, Mr. Hoyt's analysis is inconsistent in its analysis of reliability performance.
2 Depending upon the type of capital investment and O&M expenditure, Mr. Hoyt utilizes
3 different reliability metrics and tries to draw broad conclusions about the category of
4 investment. For example, with respect to vegetation management expenditures, Mr. Hoyt
5 references "a very weak, negative association with most tree-related outage metrics" and
6 focuses specifically on the number of customers interrupted in Figure 10, whereas with respect
7 to the Company's infrastructure replacement program, he references a "strongly positively
8 associated with reliability metric performance" and focuses specifically on duration of
9 outages in minutes. (OCA St. 5, pp. 83-84.) These inconsistencies fail to capture the entirety
10 of PPL Electric's reliability performance and do not take into account factors outside of the
11 Company's control, like worsening storms and off-ROW trees.

12 Fourth, Mr. Hoyt is similarly inconsistent regarding the periods he uses to attempt to
13 draw his conclusions, shifting between a focus on purported immediate versus one-year and
14 two-year lag. For example, with respect to storm-hardening and reliability initiatives under
15 the I&M Plan, Mr. Hoyt initially focuses on same-year correlations generally and specifically
16 for Smart Grid investments but then shifts to two-year lagged on a general basis.

17
18 **Q. Are there any other reasons why you do not believe that OCA Witness Hoyt's analysis**
19 **should be relied upon as justification for his conclusions and recommendations related**
20 **to the Company's reliability performance?**

21 **A.** Yes. Mr. Hoyt himself admits that his analysis shows "mixed results" as it tries to draw
22 relationships between categories of investment and reliability outcomes for different time

1 periods. The Company does not dispute that different types of investments will have different
2 impacts upon reliability performance over different time periods. Consider, for example, a
3 project that would have immediate benefit would be the Company's conversion of an existing
4 single-phase line to a multi-phase line. This type of project would both make the existing
5 conductor more resilient to outages as well as increasing the amount of vegetation clearance
6 around the conductor itself, resulting in immediate removal of outage exposure for customers
7 served through that segment. An example of a project that would have potentially delayed
8 benefit would be a newly constructed three-phase tie line. In this example, customers would
9 only see a benefit when either side of the tie sources experience an outage. It is due in part to
10 these differences that the Company takes a comprehensive approach to maintaining and
11 enhancing system reliability and seeks to diversify the work it performs on its system. For
12 this reason, it seems that Mr. Hoyt is "chasing the data" rather than engaging in an analysis
13 that could be used to meaningful evaluate or inform the Company's decision-making with
14 respect to its reliability-based investments.

15
16 **Q. Does OCA Witness Wise raise customer service-related concerns that stemmed from the**
17 **Company's reliability performance?**

18 A. Yes. Ms. Wise focused on customer service-related concerns and purported customer
19 dissatisfaction with the reliability of the Company's service that were raised during testimony
20 at the public input hearings. (OCA St. 9, pp. 18-19.)

21

1 **Q. Could you please respond to Ms. Wise’s summary regarding customer testimony at**
2 **public input hearings regarding service reliability?**

3 A. As a general matter, I understand that service outages, and in particular prolonged outages,
4 can present frustration and challenges for PPL Electric’s customers. The Company endeavors
5 to be responsive to the concerns of its customers and prioritizes its reliability investments in
6 a manner that balances the needs of specific customers with the needs of the system as a
7 whole. With respect to the testimony regarding whether the Company has a smart grid or
8 smart technology in place, I note that the Company regularly analyzes and implements such
9 technology as a part of its Smart Grid program. Contrary to these concerns, the Company’s
10 Smart Grid investments allow it to react rapidly to changes occurring on the distribution
11 system due to weather (or other) events, ultimately mitigating the impacts of outages.

12
13 **IV. STORM RESTORATION AND PLANNING**

14 **Q. Do any of the parties provide comments or propose adjustments or recommendations**
15 **related to storm restoration and planning?**

16 A. Yes. I&E Witness Walker makes recommendations regarding the Company’s Storm Damage
17 Expense Rider (“SDER”), including the level of expenses that the Company be permitted to
18 recover through the rider. (I&E St. No. 1, pp. 12-13.) He also argues that the Company’s
19 proactive investments in storm hardening undercut the need for the SDER. (I&E St. No. 1, p.
20 16.) OCA Witness Hoyt provides analysis related to storm hardening, damage, and response,
21 as well as specific recommendations related to this category of work performed by the
22 Company. (OCA St. 5, pp. 85-88, 94.)

1
2 **Q. Do you agree with I&E Witness Walker's recommendations related to the Company's**
3 **SDER?**

4 A. No.
5

6 **Q. Why not?**

7 A. Initially, I note that other Company witnesses will address certain of Mr. Walker's points, i.e.,
8 Company witness Ms. Arnold (PPL Electric St. No. 13-R). With respect to Mr. Walker's
9 claim that the Company's proposed level of expenses to be recovered through the SDER is
10 unreasonable in light of its storm hardening investments,⁴ Mr. Walker is incorrect because the
11 SDER addresses reactive expenditures made in response to storms that damage PPL Electric
12 facilities whereas the Company's storm hardening work are proactive expenditures made to
13 mitigate the impacts of storms on the Company's facilities and service. These categories of
14 expenditures serve different purposes, and while storm hardening work does mitigate the
15 impacts of storms, it does not demonstrate that the Company's SDER is unreasonable or
16 unnecessary. As mentioned previously, the Company has experienced increased frequency
17 and severity of storms, a fact which Mr. Walker does not dispute. This experience justifies
18 both the SDER and the Company's proposed level of storm hardening expenditures,
19 especially because the SDER mechanism only includes for recovery actual, incremental (to
20 base rates) storm costs.
21

⁴ I&E St. No. 1, p. 16.

1 **V. CONCLUSION**

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

3 A. Yes, it does.

WITNESS: Joseph Lookup

**PPL Electric Utilities Corporation
Response to the Set VIII Data Requests of the
Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania
(CAUSE-PA)**

Dated November 10, 2025

Docket No. R-2025-3057164

CAUSE-PA VIII-9 Refer to Lookup Direct Testimony p.19 stating “customers should see significant reductions in their transmission costs.” In live, unlocked Excel file format with all links and formulas intact, provide all analysis that the Company has conducted demonstrating that “customers should see significant reductions in their transmission costs.”

PPL Electric See CAUSE-PA VIII-9 Attachments 1 through 3 and the
Response response to CAUSE-PA IV-29.

Data Center – TSC Analysis Talking Points – Q3 Earnings call/notes

Developed 2024-10-25

Assumptions/Changes/Notes:

Q2 Analysis used data assuming that data center load would be default service
Current analysis assumes that data center load will be shopping
Assumes all load & cost scenarios are instantaneous (not phased in over time)
\$100M Plant-in-service results in ~\$12M revenue requirement
Assumes ALL else equal
Uses pricing in effect as of July 1, 2024
FERC Formula Rate changes on January 1
Price-To-Compare changes on December 1 and June 1

Talking Points

In its most recent analysis, the Company has assumed that any data center load would be in front of the meter as a shopping customer.

Investor Talking Point:

Compared to the Company's current average bill amounts, \$100M to \$1B, assuming 1GW per \$100M, of additional transmission investment results in a Transmission Service Charge reduction of ~10% [note: 8.95% rounded to 10%] to ~45% [Note: 42% rounded to 45%] resulting in a total bill decrease ranging from ~\$3 [Note: \$2.87 rounded to \$3] to ~\$15/month [Note: \$13.56 rounded to \$15] or ~\$36 to ~\$180/annually. Impact will vary as PPL Electric's rates and PJM 1CP vary.

Prior Data used in Q2 Earnings Call	RS – All Data Center Load as Default Customer	RS – All Data Center Load is Shopping	Q3 Earnings Call	RS – All Data Center Load is Shopping						
Variances vs Current (July 1, 2024)	\$100M, 1GW	\$100M, 1GW	Variances vs Current (July 1, 2024)	\$100M, 1GW	\$500M, 5GW	\$700M, 7GW	\$800M, 8GW	\$1B, 10GW	\$600M, 8GW	\$700M, 8GW
TSC Decrease %	-9.95%	-8.95%	TSC Decrease %	-8.95%	-29.90%	-35.89%	-52.53%	-42.28%	-31.92%	-30.02%
TSC Decrease \$	(\$3.19)	(\$2.87)	TSC Decrease \$	(\$2.87)	(\$9.59)	(\$11.51)	\$ (17.46)	(\$13.56)	\$ (10.61)	\$ (9.98)
PTC Decrease %	-3.18%	-2.86%	PTC Decrease %	-2.86%	-9.55%	-11.46%	-13.98%	-13.51%	-8.49%	-7.99%
PTC Decrease \$	(\$3.19)	(\$2.87)	PTC Decrease \$	(\$2.87)	(\$9.59)	(\$11.51)	\$ (17.46)	(\$13.56)	\$ (10.61)	\$ (9.98)
Total Bill Decrease %	-1.96%	-1.77%	Total Bill Decrease %	-1.77%	-5.90%	-7.09%	-9.11%	-8.35%	-5.54%	-5.21%
Total Bill Decrease \$	(\$3.19)	(\$2.87)	Total Bill Decrease \$	(\$2.87)	(\$9.59)	(\$11.51)	(\$17.46)	(\$13.56)	(\$10.61)	(\$9.98)

FERC Formula Rate and Transmission Service Charge Trend

@ \$100M Plant-In-Service & 10W Investments, assuming additional load is shopping

Capital Investment	Current Rate of \$100M C-1		\$100M C-1		\$200M C-2		\$400M C-4		\$600M C-6		\$800M C-8		\$1B C-10		\$1,500M C-15		\$2,000M C-20		\$1,700M C-17	
	June 1, 2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
FFA Impact																				
Revenue Requirement	\$ 797,094,549	\$ 808,894,404	\$ 820,694,239	\$ 844,293,969	\$ 867,893,679	\$ 891,493,389	\$ 915,093,099	\$ 938,692,804	\$ 962,292,514	\$ 985,892,224	\$ 1,009,491,934	\$ 1,033,091,644	\$ 1,056,691,354	\$ 1,080,291,064	\$ 1,103,890,774	\$ 1,127,490,484	\$ 1,151,090,194	\$ 1,174,689,904	\$ 1,198,289,614	\$ 1,221,889,324
1 C-1 Peak	7,460	8,460	8,460	8,460	11,460	13,460	13,460	13,460	17,460	18,460	18,460	18,460	22,460	23,460	23,460	27,460	28,460	28,460	32,460	34,460
1 C-2 (RWV) Peak	10,803	10,803	10,803	10,803	14,803	17,803	17,803	17,803	24,803	27,803	27,803	27,803	34,803	37,803	37,803	44,803	47,803	47,803	54,803	57,803
Incremental % Change in Rates vs Current																				
*The peak (denominator) is decreasing, decreasing the rate. This is partially offset by the higher volume which translates to \$12M for every \$100M investment.																				
**21 million equity base. Base additions times 100 plus base and production expense.																				
*Compared to the current rate, the new rate will require \$636.45M investment and \$4,393 Peak in production.																				
FFA Impact																				
NTS Rate (\$/MWH)	279.59	266.89	242.68	206.94	181.82	163.20	148.84	142.83	123.57	124.14	117.08									
NTS Cost Assumed that additional load is shipping																				
NTS Cost - Associated to Capital Groups																				
Res	\$ 227,399,460	\$ 203,941,107	\$ 185,414,244	\$ 168,128,840	\$ 138,931,656	\$ 124,703,401	\$ 113,734,178	\$ 104,141,061	\$ 95,402,564	\$ 88,554,514	\$ 82,467,813	\$ 77,092,500	\$ 72,299,460	\$ 67,947,813	\$ 64,021,107	\$ 60,500,000	\$ 57,362,500	\$ 54,500,000	\$ 51,916,667	\$ 49,500,000
SCM	\$ 414,718,807	\$ 401,521,805	\$ 394,842,234	\$ 3,098,600	\$ 23,918,823	\$ 24,521,500	\$ 22,384,117	\$ 21,400,489	\$ 19,934,452	\$ 18,652,502	\$ 17,502,500	\$ 16,468,333	\$ 15,534,167	\$ 14,699,000	\$ 13,963,333	\$ 13,316,667	\$ 12,760,000	\$ 12,293,333	\$ 11,816,667	\$ 11,430,000
LCAP	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881	\$ 8,771,881
LCM-1	\$ 629,674	\$ 649,175	\$ 613,002	\$ 477,445	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338	\$ 344,338
LCM-2	\$ 276,614,582	\$ 449,172,157	\$ 227,268,497	\$ 193,747,767	\$ 172,211,972	\$ 152,789,219	\$ 139,348,498	\$ 127,103,176	\$ 116,024,514	\$ 106,024,514	\$ 97,024,514	\$ 89,024,514	\$ 81,024,514	\$ 74,024,514	\$ 67,024,514	\$ 61,024,514	\$ 55,024,514	\$ 49,024,514	\$ 43,024,514	\$ 37,024,514
Allocation of Demand Costs(Including NTSS)																				
Res	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%	80.50%
SCM	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%	17.62%
LCAP	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%
LCM-1	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%
LCM-2	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Other Expenses																				
Res	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483	\$ 13,150,483
SCM	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481	\$ 9,262,481
LCAP	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757	\$ 6,121,757
LCM-1	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290	\$ 3,125,290
LCM-2	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012	\$ 31,660,012
Total TSC Revenue Requirement																				
Res	\$ 240,549,343	\$ 217,959,500	\$ 198,951,727	\$ 177,179,323	\$ 152,082,139	\$ 137,953,384	\$ 126,844,661	\$ 118,229,534	\$ 111,441,951	\$ 105,008,997	\$ 98,876,333	\$ 92,942,500	\$ 87,299,167	\$ 81,935,833	\$ 76,842,500	\$ 72,019,167	\$ 67,445,833	\$ 63,112,500	\$ 59,019,167	\$ 55,155,833
SCM	\$ 53,977,588	\$ 49,264,445	\$ 45,761,791	\$ 42,398,142	\$ 39,164,542	\$ 36,053,188	\$ 33,063,331	\$ 30,195,500	\$ 27,457,500	\$ 24,842,500	\$ 22,342,500	\$ 20,057,500	\$ 17,972,500	\$ 16,087,500	\$ 14,392,500	\$ 12,877,500	\$ 11,532,500	\$ 10,357,500	\$ 9,342,500	\$ 8,477,500
LCAP	\$ 11,993,118	\$ 11,387,433	\$ 10,909,774	\$ 10,274,493	\$ 9,708,958	\$ 9,241,548	\$ 8,809,227	\$ 8,397,834	\$ 7,972,333	\$ 7,572,333	\$ 7,192,333	\$ 6,832,333	\$ 6,492,333	\$ 6,172,333	\$ 5,872,333	\$ 5,592,333	\$ 5,332,333	\$ 5,092,333	\$ 4,872,333	\$ 4,672,333
LCM-1	\$ 3,754,365	\$ 3,688,479	\$ 3,630,286	\$ 3,562,739	\$ 3,495,689	\$ 3,428,268	\$ 3,360,493	\$ 3,293,268	\$ 3,226,593	\$ 3,160,368	\$ 3,094,593	\$ 3,029,268	\$ 2,964,368	\$ 2,900,000	\$ 2,836,000	\$ 2,772,500	\$ 2,709,500	\$ 2,647,000	\$ 2,584,500	\$ 2,522,000
LCM-2	\$ 130,274,334	\$ 281,322,628	\$ 138,568,350	\$ 234,425,739	\$ 201,681,888	\$ 184,483,311	\$ 171,035,133	\$ 156,316,194	\$ 140,345,529	\$ 124,122,867	\$ 107,749,333	\$ 91,219,167	\$ 74,542,500	\$ 57,816,667	\$ 41,042,500	\$ 24,268,333	\$ 7,494,167	\$ -11,727,500	\$ -38,952,500	\$ -66,177,500
Billing Determinant																				
Res (RWV)	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402	7,707,936,402
SCM (RWV)	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652	1,820,182,652
LCAP (RWV)	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748	907,748
LCM-1 (RWV)	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8	70.8
Rate																				
Res	\$ 0.03024	\$ 0.02993	\$ 0.02728	\$ 0.02381	\$ 0.02097	\$ 0.01861	\$ 0.01668	\$ 0.01507	\$ 0.01374	\$ 0.01266	\$ 0.01177	\$ 0.01100	\$ 0.01033	\$ 0.00975	\$ 0.00926	\$ 0.00877	\$ 0.00828	\$ 0.00779	\$ 0.00730	\$ 0.00681
SCM	\$ 0.03351	\$ 0.03282	\$ 0.02970	\$ 0.02556	\$ 0.02138	\$ 0.01822	\$ 0.01554	\$ 0.01329	\$ 0.01144	\$ 0.00997	\$ 0.00877	\$ 0.00780	\$ 0.00703	\$ 0.00636	\$ 0.00578	\$ 0.00529	\$ 0.00480	\$ 0.00431	\$ 0.00382	\$ 0.00333
LCAP	\$ 71.522	\$ 70.245	\$ 63.990	\$ 54.421	\$ 47.261	\$ 41.261	\$ 36.008	\$ 31.504	\$ 27.749	\$ 24.666	\$ 22.249	\$ 20.489	\$ 18.944	\$ 17.599	\$ 16.449	\$ 15.394	\$ 14.434	\$ 13.569	\$ 12.799	\$ 12.124
LCM-1	\$ 6.66353	\$ 6.5378	\$ 6.4563	\$ 6.3476	\$ 6.2079	\$ 6.0389	\$ 5.8408	\$ 5.6133	\$ 5.3562	\$ 5.0704	\$ 4.7577	\$ 4.4183	\$ 4.0529	\$ 3.6613	\$ 3.2429	\$ 2.8065	\$ 2.3521	\$ 1.8797	\$ 1.3893	\$ 0.8799
LCM-2	\$ 121.522	\$ 120.245	\$ 118.990	\$ 117.521	\$ 116.008	\$ 114.441	\$ 112.818	\$ 111.139	\$ 109.404	\$ 107.614	\$ 105.769	\$ 103.869	\$ 101.914	\$ 100.004	\$ 98.034	\$ 96.004	\$ 93.914	\$ 91.764	\$ 89.554	\$ 87.284
Residential Customer Bill Impact (Variances vs Oct 1, 2024 Pricing)																				
Res TSC Bill	\$ 33.24	\$ 29.93	\$ 27.38	\$ 23.61	\$ 20.97	\$ 18.01	\$ 15.49	\$ 13.66	\$ 12.17	\$ 10.90	\$ 9.84	\$ 8.96	\$ 8.16	\$ 7.44	\$ 6.80	\$ 6.24	\$ 5.75	\$ 5.33	\$ 4.97	\$ 4.66
Generation Component	\$ 92.87	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67	\$ 91.67
1 C-1 Peak	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803	\$ 10,803
Price to Compare Total	\$ 114.91	\$ 112.60	\$ 110.50	\$ 107.58	\$ 104.84	\$ 102.34	\$ 100.00	\$ 97.84	\$ 95.84	\$ 93.96	\$ 92.16	\$ 90.44	\$ 88.80	\$ 87.24	\$ 85.76	\$ 84.36	\$ 83.00	\$ 81.68	\$ 80.40	\$ 79.16
Distribution Portion of Bill																				
Total Bill	\$ 191.63	\$ 188.32	\$ 185.77	\$ 182.00	\$ 178.36	\$ 174.40	\$ 170.88	\$ 167.55	\$ 164.39	\$ 161.39	\$ 158.54	\$ 155.84	\$ 153.28	\$ 150.84	\$ 148.52	\$ 146.32	\$ 144.24	\$ 142.28	\$ 140.44	\$ 138.72
% Difference in Current	-1.73%	-3.06%	-4.60%	-6.40%	-8.20%	-10.00%	-11.80%	-13.60%	-15.40%	-17.20%	-19.00%	-20.80%	-22.60%	-24.40%	-26.20%	-28.00%	-29.80%	-31.60%	-33.40%	-35.20%
% Difference vs Current	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)	(-)
TSC Decrease %																				
Res	-0.93%	-0.93%	-0.88%	-0.83%	-0.77%	-0.71%	-0.65%	-0.59%	-0.53%	-0.47%	-0.41%	-0.35%	-0.29%	-0.23%	-0.17%	-0.11%	-0.05%	0.01%	0.07%	0.13%
SCM	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0.26%	-0				

TSC Trend

[illegible]

FFR Trend
PA FERC Formula Rate Sensitivity

	Current Rate	\$100M Capital Investment + 1 GW Increase	\$200M Capital Investment + 2 GW Increase	\$400M Capital Investment + 4 GW Increase	\$600M Capital Investment + 6 GW Increase	\$800M Capital Investment + 8 GW Increase	\$1B Capital Investment + 10 GW Increase	\$1,100M Capital Investment + 11 GW Increase	\$1,300M Capital Investment + 13 GW Increase	\$1,500M Capital Investment + 15 GW Increase	\$1,700M Capital Investment + 17 GW Increase	\$600M Capital Investment + 8 GW Increase	\$700M Capital Investment + 8 GW Increase
Total Plant In Rate Base	8,849,909,432	100,000,000	200,000,000	400,000,000	600,000,000	800,000,000	1,000,000,000	1,100,000,000	1,300,000,000	1,500,000,000	1,700,000,000	600,000,000	700,000,000
Total Accumulated Depreciation	(1,105,927,805)	(2,380,952)	(4,761,905)	(9,523,810)	(14,285,714)	(19,047,619)	(23,809,524)	(26,190,476)	(30,952,381)	(35,714,286)	(40,476,190)	(14,285,714)	(16,666,667)
ADIT	(1,180,228,594)	(1,619,048)	(3,238,095)	(6,476,190)	(9,714,286)	(12,952,381)	(16,190,476)	(17,809,524)	(21,047,619)	(24,285,714)	(27,523,810)	(9,714,286)	(11,333,333)
Other	9,133,320	-	-	-	-	-	-	-	-	-	-	-	-
Rate Base	6,572,886,354	96,000,000	192,000,000	384,000,000	576,000,000	768,000,000	960,000,000	1,056,000,000	1,248,000,000	1,440,000,000	1,632,000,000	576,000,000	672,000,000
Debt %	44.0%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%	44.1%
Equity %	56.0%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%	55.9%
Cost of Debt	4.74%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%	3.83%
Common Cost	10.50%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%
Rate of Return	7.97%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%	7.56%
Investment Return	523,716,177	7,258,678	14,517,355	29,034,711	43,552,066	58,069,422	72,586,777	79,845,455	94,362,810	108,880,166	123,397,521	43,552,066	50,810,744
State & Fed Tax	27.31%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%	27.71%
T / (1-T)	37.57%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%	38.33%
Income Tax Component	145,325,903	2,160,225	4,320,450	8,640,899	12,961,349	17,281,799	21,602,249	23,762,473	28,082,923	32,403,373	36,723,822	12,961,349	15,121,574
Depreciation Expense	178,871,247	2,380,952	4,761,905	9,523,810	14,285,714	19,047,619	23,809,524	26,190,476	30,952,381	35,714,286	40,476,190	14,285,714	16,666,667
Rev Req Impact		11,799,855	23,599,710	47,199,420	70,799,130	94,398,840	117,998,550	129,798,405	153,398,114	176,997,824	200,597,534	70,799,130	82,598,985
Total Rev Req	797,094,549	808,894,404	820,694,259	844,293,969	867,893,679	891,493,389	915,093,099	926,892,954	950,492,664	974,092,374	997,692,084	867,893,679	879,693,534
1 CP Peak	7,459.6	8,459.6	9,459.6	11,459.6	13,459.6	15,459.6	17,459.6	18,459.6	20,459.6	22,459.6	24,459.6	15,459.6	15,082.7
Rate (\$/MW-Year)	\$ 106,855	\$ 95,619	\$ 86,758	\$ 73,676	\$ 64,481	\$ 57,666	\$ 52,412	\$ 50,212	\$ 46,457	\$ 43,371	\$ 40,789	\$ 56,139	\$ 58,325
Variance to current rate		\$ (11,236)	\$ (20,097)	\$ (33,179)	\$ (42,373)	\$ (49,189)	\$ (54,443)	\$ (56,643)	\$ (60,398)	\$ (63,484)	\$ (66,065)	\$ (50,715)	\$ (48,530)
% Variance to current rate		-10.5%	-18.8%	-31.1%	-39.7%	-46.0%	-51.0%	-53.0%	-56.5%	-59.4%	-61.8%	-47.5%	-45.4%
PPL Zone NITS Charge (\$/MWD)	\$ 297.5929	\$ 266.8934	\$ 242.6831	\$ 206.9399	\$ 181.8169	\$ 163.1967	\$ 148.8415	\$ 142.8306	\$ 132.5710	\$ 124.1393	\$ 117.0847	\$ 159.0246	\$ 164.9973
Variance to prior rate		\$ (11,236)	\$ (8,861)	\$ (13,082)	\$ (9,194)	\$ (6,815)	\$ (5,254)	\$ (2,200)	\$ (3,755)	\$ (3,086)	\$ (2,581)	\$ (106,855)	\$ (106,855)
% Variance to prior rate		-10.5%	-9.3%	-15.1%	-12.5%	-10.6%	-9.1%	-4.2%	-7.5%	-6.6%	-6.0%	-100.0%	-100.0%

June 1, 2025 Bill Calcs				
Tariff Schedule	RS	GS1	GS3	LP4
KwH	1,000	1,000	15,000	15,000
KW	0	4	75	75
ICAP	0	0	0	370
Customer				
Base Distr	14.09	22.00	60.00	169.80
SMR2	1.62	3.26	3.26	68.41
CER	(0.01)	(0.01)	(0.01)	0.05
SDER (Cust)	-	-	-	9.13
Variable				
Base Distr	35.34	17.44	298.88	191.03
ACR3	2.20	1.66	24.90	281.57
SDER (variable)	1.84	0.92	13.80	-
USR	11.11	-	-	-
	66.19	45.27	400.83	719.99
TCJA	(3.95)	(3.16)	(28.71)	(27.68)
DSIC	4.67	3.16	27.91	34.62
	66.91	45.28	400.03	726.93
STAS D	(0.187300)	(0.126800)	(1.120100)	(1.51)
Total Distribution	66.72	45.15	398.90	725.41
Energy	91.67	89.56	1,343.40	RTP
Transmission	33.24	31.58	473.70	RTP
STAS E&T	0.001249	0.001211	0.018171	RTP
Total Bill Per Month	191.63	166.29	2,216.02	725.41
PTC	124.91	121.14	1,817.12	

Non-Shopping, 1GW Increase, \$100M Investment			
RS	GS1	GS3	
1,000	1,000	15,000	
0	0	0	
0	0	0	
14.09	22.00	60.00	
1.62	3.26	3.26	
(0.01)	(0.01)	(0.01)	
-	-	-	
35.34	17.444	298.875	
2.2	1.66	24.9	
1.84	0.92	13.80	
11.11	0	0	
66.19	45.27	400.83	
(3.95)	(3.16)	(28.71)	
4.67	3.16	27.91	
66.91	45.28	400.03	
(0.187300)	(0.126800)	(1.120100)	
66.72	45.15	398.90	
91.67	89.56	1,343.40	
28.88	19.61	294.15	
0.001206	0.001092	0.016376	
187.27	154.32	2,036.47	
120.55	109.17	1,637.57	
RS	GS1	GS3	
-13.12%	-37.90%	-37.90%	
\$ (4.36)	\$ (11.97)	\$ (179.55)	
-2.28%	-7.20%	-8.10%	
\$ (4.36)	\$ (11.97)	\$ (179.55)	
-3.49%	-9.88%	-9.88%	
\$ (4.36)	\$ (11.97)	\$ (179.55)	

Shopping, 1GW Increase, \$100M Investment			
RS	GS1	GS3	
1,000	1,000	15,000	
0	0	0	
0	0	0	
14.09	22.00	60.00	
1.62	3.26	3.26	
(0.01)	(0.01)	(0.01)	
-	-	-	
35.34	17.444	298.875	
2.2	1.66	24.9	
1.84	0.92	13.80	
11.11	0	0	
66.19	45.27	400.83	
(3.95)	(3.16)	(28.71)	
4.67	3.16	27.91	
66.91	45.28	400.03	
(0.187300)	(0.126800)	(1.120100)	
66.72	45.15	398.90	
91.67	89.56	1,343.40	
29.20	19.84	297.60	
0.001209	0.001094	0.016410	
187.59	154.55	2,039.92	
120.87	-	1,641.02	
RS	GS1	GS3	
-12.15%	-37.18%	-37.18%	
\$ (4.04)	\$ (11.74)	\$ (176.10)	
-2.11%	-7.06%	-7.95%	
\$ (4.04)	\$ (11.74)	\$ (176.10)	
-3.23%	-9.69%	-9.69%	
\$ (4.04)	\$ (11.74)	\$ (176.10)	

Estimate the generation portion of the bill would need to increase by more than [XX%] to exceed savings

Energy	0.00%		
	91.67	89.56	1,343.40

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
NICOLE HOWELL
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: Vegetation Management

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicole Howell, and my business address is 827 Hausman Road, Allentown, PA 18104.

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

A. I am employed by PPL Electric Utilities Corporation (“PPL Electric” or the “Company”), a subsidiary of PPL Corporation (“PPL Corp.”), as Manager – Vegetation Management & Program Management.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my Rebuttal Testimony is to respond to testimony supplied by the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation and Enforcement (“I&E”) and the Office of Consumer Advocate (“OCA”), related to the Company’s vegetation management practices and claims in this case. I specifically address I&E Witnesses Walker (I&E Statement No. 1) and Tarr (I&E Statement No. 4), as well as OCA Witnesses Morgan (OCA Statement No. 1), Hoyt (OCA Statement No. 5), and Wise (OCA St. No. 9).

1 **II. VEGETATION MANAGEMENT**

2 **Q. What does I&E Witness Walker recommend with respect to the Company's vegetation**
3 **management expense claim?**

4 A. Mr. Walker recommends a reduction to the Company's vegetation management expense
5 claim of \$15,579,000, based upon the use of a three-year historical average of the Company's
6 annual fiscal year vegetation management expense. (I&E St. No. 1, pp. 27-28.)
7

8 **Q. In your opinion, is this a reasonable method by which to calculate the Company's**
9 **vegetation management expense claim?**

10 A. No. A historic average is not representative of the Company's year-to-year plan given its
11 expansive and disparate service territory as it pertains to vegetation growth. Further, it
12 undermines the reasoning and allowance of a Fully Projected Future Test Year. Lowering the
13 expense claim by \$15 million will increase the trim cycle to 7-8 years. An increase in the trim
14 cycle will allow for additional vegetation growth on the system, which will become
15 increasingly more expensive to maintain. The reduced investment will also limit the 7%
16 SAIFI improvements PPL Electric is projecting from its proposal.
17

18 **Q. Are there other reasons why Mr. Walker's adjustment should be rejected?**

19 A. Yes, Mr. Walker presumes that the Company can achieve the reliability improvements
20 anticipated from its proposed vegetation maintenance plan without increasing its vegetation
21 maintenance budget. Mr. Walker bases this presumption on the Company's usage of efficient

1 integrated vegetation management (“IVM”) techniques, including herbicides and LiDAR,
2 which “creates a cycle of increasing returns and decreases the frequency for readdressing the
3 same areas.” (I&E St. No. 1, p. 28.) I agree that the Company utilizes innovative vegetation
4 management techniques to efficiently address vegetation in its service territory. However,
5 vegetation contact remains a leading cause of outages on PPL Electric’s system, and to
6 improve reliability, the Company is required to increase its vegetation maintenance budget
7 with the express purpose of trimming and removing trees.

8 Additionally, there are several inaccuracies in Mr. Walker’s testimony. It is not
9 accurate that I would like to highlight. LiDAR is a useful tool in efficiently managing
10 vegetation growth. However, LIDAR data is only collected every other year, and this data
11 collection is only performed on the transmission system, not on the distribution system and
12 cannot be used as justification to reduce the vegetation maintenance claim for the distribution
13 system. Mr. Walker also overstates the effectiveness of herbicide usage in decreasing the
14 amount of vegetation maintenance needed on the system. Although the use of herbicide for
15 brush control is effective in decreasing the need for work over time, it is merely a single part
16 of the overall prescription for vegetation maintenance activities across the PPL Electric
17 system.

18 There are over 15,000 tree miles across the territory, and the vegetation continues to
19 grow, resulting in the need for maintenance activities such as trimming or removal to be done
20 for safety and reliability for PPL Electric’s customers. The use of technology, such as LiDAR,
21 supports the identification of risk and prioritization of work, but it does not stop the need for
22 maintenance activities and an adequate budget to support those activities.

1
2 **Q. Do the other parties have a position on the Company's proposal to capitalize the first**
3 **cut of vegetation associated with acquiring enhanced ROW rights to address off-ROW**
4 **trees?**

5 A. Yes. I&E Witness Mr. Walker, OCA Witness Hoyt, and OCA Witness Morgan disagree with
6 the Company's proposal. They generally argue that the proposal is inconsistent with FERC
7 accounting rules, and that the Company has not justified the request. (I&E St. No. 1, p. 29,
8 OCA St. No. 5, p. 63.)
9

10 **Q. How do you respond to Mr. Walker and Mr. Hoyt regarding the proposed capitalization**
11 **of certain vegetation maintenance work?**

12 A. I disagree with the opposition to the Company's proposal to capitalize the first removal of
13 hazard and danger trees after the acquisition of enhanced rights to do so. I note that the capital
14 request to clear newly acquired rights will allow the Company to improve right-of-way
15 ("ROW") corridors for an estimated 500-800 additional miles annually. Establishing
16 additional clearance is a required initial action beyond that of routine maintenance of an
17 existing corridor. In fact, the cost to clear vegetation in new construction can be more than 5
18 times per mile compared to vegetation maintenance activities. While the Company's proposal
19 does not involve the construction of new facilities, the vegetation activities of widening to
20 establish additional clearance is similar to the activities the Company performs during
21 greenfield construction. The capitalization will allow the Company to establish additionally
22 acquired ROW clearance, to prioritize addressing off-ROW trees in a manner that will result

1 in significant reliability improvements. Thus, the Company's proposal to capitalize this work
2 is reasonable and justified.

3
4 **Q. Mr. Hoyt has an additional recommendation regarding reporting requirements**
5 **associated with the capital treatment of this vegetation work.**

6 A. Mr. Hoyt recommends that the Commission objectively evaluate enhanced ROW
7 performance relative to the Company's stated benefit of an additional 7% improvement in
8 SAIFI over 5 years. (OCA St. No. 5, pp. 63-64.) He goes on to recommend that failure to
9 demonstrate progress toward this metric should result in enhanced prudence review and
10 potential disallowance of enhanced ROW-related costs.

11 I do not disagree with the reporting requirements proposed by Mr. Hoyt if the
12 Commission adopts the Company's proposal. PPL Electric currently reports on quantities
13 and miles of vegetation maintenance performed on a quarterly basis and would be willing to
14 report out on additional clearing work associated with extended rights. The Company also
15 provides routine reliability reports to the Commission and sees no issue with continuing to do
16 so. However, I am advised by counsel that to the extent that Mr. Hoyt is proposing a
17 performance-based rate, his recommendation should be rejected. Only PPL Electric can
18 propose a performance-based rate, and the Company will address this issue in further detail
19 in its brief.

20

1 **Q. How does Mr. Hoyt summarize the association of Vegetative Management Program**
2 **Capital Spending and Non-Trimming Related tree outage metrics?**

3 A. Mr. Hoyt notes that the association between these two factors “may suggest that capital
4 investments in vegetative management address broader vegetation risks beyond routine
5 trimming,” but that this relationship is “modest,” and that interpretation of results was limited
6 by a small sample size. (OCA St. No. 5, pp. 84-85.)

7
8 **Q. Do you agree with this summary?**

9 A. No. Vegetation management capital spend from 2021-2024 was not associated with
10 vegetation removal itself, it was specifically for back office systems related to vegetation work
11 planning and the first time build out of the vegetation management work planning software.
12 The Company does not currently have a capital vegetation maintenance plan to address off-
13 ROW trees. It is impossible to predict the efficacy of PPL Electric’s proposed capital
14 vegetation maintenance plan based on prior capital spend in this area given the dissimilarities
15 between the Company’s prior capital vegetation maintenance spend and what it is proposing
16 in this rate case.

17
18 **Q. Does Mr. Morgan make any recommendations regarding the Company’s capitalization**
19 **of the cost of first clearing and grading of land and ROW?**

20 A. Yes. Mr. Morgan recommends that the Commission deny the Company’s proposal to
21 capitalize the cost of first clearing and grading of land and ROW. (OCA St. No. 1, pp. 27-
22 28.)

1
2 **Q. Do you agree with this recommendation?**

3 A. No. Mr. Morgan incorrectly interprets FERC accounting guidance as discussed further in PPL
4 Electric Witness Sharon Leskowsky's rebuttal testimony (PPL Electric St. No. 22-R).

5
6 **Q. Does OCA Witness Morgan express any concerns regarding the Company's vegetation**
7 **management expense claim?**

8 A. Mr. Morgan testifies that "there are additional pieces of information that need to be understood
9 about the Company's Vegetation management program," which are needed to "reasonably
10 address the vegetation management program" and identifies five areas where he purports
11 information is lacking which are listed below.

12 (1) PPL Electric has not shown cost savings in its cost of service;

13 (2) PPL Electric should provide a 5-year comparison of actual vs. budgeted vegetation
14 management spending by activity;

15 (3) PPL Electric did not supply its 5-year vegetation management operating budget;

16 (4) PPL Electric should provide a more detailed breakdown of its vegetation management
17 capital budget, including enhanced off-ROW spending; and

18 (5) PPL Electric should supply details on contractor negotiations, including documented
19 savings. (OCA St. No. 1, pp. 27-28.)

20

1 **Q. Do you agree with Mr. Morgan’s assertion that there is not sufficient information**
2 **available to allow the other parties to form a recommendation regarding the Company’s**
3 **vegetation management expense claim?**

4 **A.** No. I do not agree that the Company failed to provide enough information such that the
5 Commission can adequately evaluate other parties’ recommendations regarding the
6 Company’s vegetation management expense claim. No other witnesses raised this issue, and
7 I&E Witness Walker was able to form and provide a recommended adjustment to the
8 Company’s vegetation management expense claim. Regarding the specific information which
9 Mr. Morgan avers is missing, I will address each issue in turn:

10 1. **Cost Savings.** PPL Electric has not reflected any cost savings in the cost of service because
11 it is complex to quantify. All efficiencies are reinvested into the vegetation maintenance
12 program so that additional activities can be performed. PPL Electric has been executing a
13 unit style contract since 2019, quantifying the work at a very granular level (e.g., price per
14 tree based on class and diameter, acre of brush removed and foot of tree trimmed). This
15 allows for detailed cost control to ensure work is executed as efficiently as possible.

16 2. **Actual vs. Budgeted Vegetation Management Spend.** Please see Table 1 below, which
17 provides an overview of the Company’s annual O&M-related vegetation spend for the past
18 10 years.

**Table 1. Actual Annual Operations & Management-Related Vegetation Spend
(2015-2025)**

Vegetation Spend		
Year		O&M \$s
2015	\$	44,759,231
2016	\$	54,965,816
2017	\$	38,400,322
2018	\$	35,417,197
2019	\$	38,846,278
2020	\$	29,341,985
2021	\$	27,228,203
2022	\$	25,892,633
2023	\$	23,145,197
2024	\$	41,591,999
2025	\$	26,193,768

- 3.
4. **5-Year Vegetation Management Operating Budget.** The Company does not have historic operating budgets as those targets are often adjusted mid-year to meet operational needs. However, in my experience the Company does not have difficulty in spending its allocated funding for vegetation maintenance. I am confident that if the Company's proposal for a \$50 million vegetation management budget is approved, PPL Electric will be able to execute on that budget and improve reliability for customers.
4. **Breakdown of Vegetation Management Capital Budget.** The detail requested by Mr. Morgan is not available. The Company has projected that the \$25 million capital budget will allow it to address 500-800 miles of line annually. However, the exact makeup of that spend is dependent on several variables which are outside of the Company's control. Specifically, it is difficult to predict what ROW costs will be until the Company enters into negotiations with landowners. Likewise, the amount and nature of off-ROW trees will differ by location, making these costs difficult to predict with the specificity requested.

1 However, the Company is agreeable to Mr. Hoyt's additional reporting recommendation
2 for this work which should resolve Mr. Morgan's concerns.

- 3 5. **Negotiation with Contractors.** PPL Electric successfully negotiated approximately
4 \$700,000 of savings from initial bid to final award for the most recent 2026 RFP. Remote
5 sensing technology and historical unit data was analyzed to create a future prediction of
6 work volumes at the circuit level. The work volumes were used to estimate the cost of each
7 circuit and used as a comparison, forecast, and ultimately a negotiation tool to drive down
8 costs of work with vendors.

9
10 **Q. Does OCA Witness Hoyt make a recommendation regarding the Company's vegetation**
11 **management program?**

12 A. Yes, Mr. Hoyt recommends that, as a condition of approving the vegetation I&M change, the
13 Commission require the Company "to continue planning and executing I&M work based on
14 system risk and need, rather than cycle length alone." (OCA St. No. 5, p. 63.)

15
16 **Q. Do you agree with this recommendation?**

17 A. Yes. As described in my direct testimony, PPL Electric's Vegetation Management program
18 utilizes data to evaluate system risk and impact to plan and execute vegetation maintenance.
19 (PPL Electric St. No. 17, p. 3.) Vegetation growth in proximity to PPL Electric's distribution
20 system must be addressed regardless, but how and when it is prioritized will always be
21 considered and planned based on the potential risk it poses to reliability.

22

1 **Q. How does Mr. Hoyt summarize OCA’s analysis of same-year and prior-year Vegetation**
2 **Management Program O&M spending?**

3 A. Mr. Hoyt notes that, for “PUC Reportable and PUC Major events, same-year Vegetation
4 Management Program O&M spending exhibits a very weak, negative association with most
5 tree-related outage metrics.” (OCA St. No. 5, p. 83.) Mr. Hoyt avers that this association might
6 indicate a weak “immediate relationship between spending and reliability outcomes in the
7 year in which expenditures occur.” (*Id.*)

8 Mr. Hoyt further notes that there is a stronger and more consistent negative association
9 with tree-related outage metrics, and he avers that this association might indicate that “larger
10 O&M investments in vegetative management are associated with reduced outages following
11 a time lag, and vice versa.” (OCA St. No. 5, p. 84.)

12
13 **Q. Are the above summaries consistent with the results that the Company might expect?**

14 A. Yes. There are over 28,000 overhead distribution miles on PPL Electric’s system. Maintaining
15 3,000-6,000 miles per year may not have an immediate impact on reliability. There are many
16 factors that can impact reliability across the system, such as years of growth, weather, tree
17 density, rights, and vegetation proximity to line, all of which contribute to performance. There
18 are approximately 43 million trees with overstrike within 10 feet of PPL Electric’s distribution
19 lines, and the Company’s program targets approximately 12,000 annually.

20

1 **Q. Did OCA Witness Wise raise customer service-related concerns that stemmed from the**
2 **Company’s vegetation management?**

3 A. Yes. Ms. Wise testified that four customers testified during public input hearings regarding
4 vegetation management concerns. One customer stated that, during winter storms, “anywhere
5 [he] drive[s] through, where it’s PPL, trees just hanging on the wires. They just cut enough
6 for the cars to get through, and they leave it there months at a time.” (OCA St. No. 9, p. 19.)
7 Another customer asked whether vegetation management was part of the Company’s
8 requested increase, stating that there are “trees hanging on the power lines,” within cities.
9 (OCA St. No. 9, p. 20.) A third customer testified that he experienced a 75-hour service
10 interruption in 2011, and that “if the trees were trimmed the way they were supposed to be
11 under the vegetation management specs that PPL has, there would not have been an outage
12 for that long of a time in my area.” (*Id.*) Finally, another witness testified that the Company
13 should improve the efficiency of the work crews responsible for trimming the trees, who “took
14 an inordinate amount of time to finish the job,” in that customer’s area. (*Id.*)

15
16 **Q. Do you have a response to the assertions made by these four customers regarding**
17 **vegetation management?**

18 A. Yes, PPL Electric’s Vegetation Management program is designed to effectively and
19 efficiently manage vegetation growth across the Company’s system. All work performed is
20 planned to specification, executed, and then verified for quality and alignment to specification.
21 However, there may be isolated incidents where the Company performs below its standards,
22 and PPL Electric is committed to identifying those incidents and improving upon them.

1 Finally, the outage noted by the customer in Bethlehem was during the October 2011 winter
2 storm, which is a top 5 storm in PPL Electric's history. This was 15 years ago, and the
3 Company has instituted many improvements to its storm response with respect to vegetation
4 maintenance since that time. PPL Electric's vegetation maintenance program has improved
5 greatly since 2011 and will continue to improve in the future with appropriate funding levels
6 as included in the Company's request.

7
8 **Q. Does I&E Witness Tarr indicate whether he has any concerns regarding the Company's**
9 **"make safe" program?**

10 A. Yes. Mr. Tarr states that "[i]t is unclear if PPL has a provision in its 'make safe' program that
11 covers the cost of cover-up services for contractors." (I&E St. No. 5, p. 3.) Mr. Tarr also notes
12 that my statement on the make safe program focuses on vegetation management and does not
13 appear to provide support for homeowners or small businesses. (I&E St. No. 5, p. 4.)

14
15 **Q. Does Mr. Tarr make any recommendations regarding the Company's make safe**
16 **program?**

17 A. Yes. Mr. Tarr recommends that the Company "introduce a free or reduced cost 'make safe'
18 service, offering up to \$1,000 or more for contractors and homeowners to encourage them to
19 request 'make safe' cover up services." (I&E St. No. 5, p. 5.)

20
21 **Q. Do you agree with this recommendation?**

22 A. No.

1

2 **Q. Why not?**

3 A. The Company has concerns with offering cover ups for make safe programs, as it can give
4 homeowners and contractors who are not trained to work in the vicinity of energized lines a
5 false sense of confidence. Rather, PPL Electric prefers that only qualified contractors work in
6 and around its facilities. The Company also offers education on how to safely operate near
7 electrical equipment. Additionally, the Company will perform, as requested, trimming for
8 customers to allow customers and contractors to work safely around our facilities.

9

10 **III. CONCLUSION**

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

12 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
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Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
LISA NORDEN
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Customer Service Performance**
 Low-Income Customer Issues
 Payment Transaction Fees
 Universal Service Programs
 Supplier Tariff

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lisa Norden, and my business address is PPL Electric Utilities 827 Hausman Road, Allentown, PA 18104.

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

A. I am employed by PPL Electric Utilities Corporation (“PPL Electric” or the “Company”), a subsidiary of PPL Corporation, as Vice President Customer Services.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony on behalf of the Company, PPL Electric Statement No. 18.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the direct testimony submitted by other parties’ witnesses, namely the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of Investigation and Enforcement (“I&E”) Witness Christopher Keller (I&E St. No. 2), the Office of Consumer Advocate (“OCA”) Witnesses Lafayette Morgan (OCA St. 1), Barbara R. Alexander (OCA St. 7), Roger Colton (OCA St. 8), and LeeAnn Wise (OCA St. 9), Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (“CAUSE-PA”) Witness Patrick M. Cicero (CAUSE-PA St. No. 1), Commission on Economic Opportunity (“CEO”) Witness Jennifer Warabak (CEO St. No. 1), Energy Justice

Advocates (“EJA”) Witness Karl A. Rábago (EJA St. No. 1), and Retail Energy Supply Association (“RESA”) Witness Frank Lacey (RESA St. No. 1). In particular, I address allegations and recommendations concerning: (1) the Company’s customer service performance; (2) low-income customers; (3) PPL Electric’s proposal to recover the costs of payment transaction fees in base rates; (4) the Company’s universal service programs and related proposals; and (5) PPL Electric’s proposed Supplier Tariff, which was attached to my direct testimony as PPL Electric Exhibit LN-1. My rebuttal testimony addresses those subjects in that order.

Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?

A. Yes, attached to my testimony are the following exhibits:

- PPL Electric Exhibit LN-1R – Answer to CAUSE-PA VI-19 and CAUSE-PA VI-19 Attachments 1, 2, 3, 4, and 6
- PPL Electric Exhibit LN-2R – Answer to OCA VII-19 and OCA VII-19 Attachment 1
- PPL Electric Exhibit LN-3R – Answer to OCA VII-20
- PPL Electric Exhibit LN-4R – EJA Answer to PPL to EJA-III-1
- PPL Electric Exhibit LN-5R – OCA Answer to PPL to OCA-III-4
- PPL Electric Exhibit LN-6R – OCA Answer to PPL to OCA-III-5
- PPL Electric Exhibit LN-7R – OCA Answer to PPL to OCA-III-6
- PPL Electric Exhibit LN-8R – OCA Answer to PPL to OCA-III-7
- PPL Electric Exhibit LN-9R – PPL-OCA-1-32- RDC FINAL Direct – UI CT – rates, Appx. 2
- PPL Electric Exhibit LN-10R – Answer to OCA XXV-18

- PPL Electric Exhibit LN-11R – EJA Answer to PPL to EJA-II-6
- PPL Electric Exhibit LN-12R – Answer to CAUSE-PA I-20 and CAUSE-PA I-20 Attachment 1
- PPL Electric Exhibit LN-13R – RESA Answer to PPL to RESA-II-3
- PPL Electric Exhibit LN-14R – Answer to RESA I-23
- PPL Electric Exhibit LN-15R (CONFIDENTIAL) – CAUSE-PA VI-19 Attachment 5 (CONFIDENTIAL)
- PPL Electric Exhibit LN-16R – OCA VII-20 Attachment 1

II. CUSTOMER SERVICE PERFORMANCE

Q. Before addressing other parties’ allegations and recommendations in detail, could you please generally address concerns that parties have raised about the Company’s customer service performance?

A. PPL Electric takes its responsibility to provide quality customer service to its customers seriously. To that end, the Company continually evaluates changes to its customer service processes and procedures, including updates to training materials or adjustments to its customer service representative staffing, and upgrades to its information technology (“IT”) that can improve customer experience, all with a goal to provide quality customer service that exceeds its peer electric utilities in Pennsylvania. At the same time, PPL Electric aims to be efficient and targeted in its related operation and maintenance (“O&M”) expenses and capital costs incurred to provide that service, recognizing the downstream impact those expenditures can have on customers’ rates and bills. I believe the Company has achieved those goals.

1 For example, in the Commission’s 2024 Customer Service Performance Report,
2 which was recently issued in December 2025, PPL Electric exceeded the industry average in
3 customer satisfaction in all the reported categories for customer contacts in 2024: (1)
4 “Overall”; (2) “Credit/Collection”; and (3) “Other,” which includes contacts to an electric
5 utility about “trouble or power outages, billing matters, connect/disconnect requests, customer
6 choice and miscellaneous issues such as requests for rate information or name and address
7 change.”¹ Specifically, 81%, 77%, and 83% of PPL Electric’s customers reported being
8 satisfied in those three categories in 2024, respectively, compared to the industry average of
9 78%, 75%, and 79%, respectively. As noted in the report, “[c]onsumers judge their overall
10 satisfaction with a utility company based on several factors, including how easy it is to reach
11 the company, the usability of its automated phone system, wait times to speak with a
12 representative, and the courtesy and knowledge of that representative.”²

13 In addition, the Company excelled in its field representatives’ performance. As an
14 example, in 2024, PPL Electric had the highest marks of all the major electric utilities in
15 customers’ “Satisfaction that Field Rep Responded Promptly” (i.e., 83%), “Satisfaction that
16 Work Completed in a Timely Manner” (i.e., 94%), and “Overall Satisfaction with the Way
17 Premises Visit Handled” (i.e., 87%).³

18 Similar findings can be found with customers’ satisfaction with the Company’s
19 automated telephone system and wait times to speak with a Company representative.

¹ PaPUC 2024 Customer Service Performance Report, p. 29 (Dec. 2025), available at <https://www.puc.pa.gov/media/3762/2024-customer-service-performance-report-final.pdf>.

² *Id.*, p. 28.

³ *Id.*, p. 24.

1 Specifically, in 2024, 72% of PPL Electric's customers reported ease of using the Company's
2 automated telephone system (compared to 63% industry average), 68% of the Company's
3 customers were satisfied with the choices offered by that automated telephone system
4 (compared to 61% industry average), and 75% of PPL Electric's customers expressed
5 satisfaction with the wait time to speak with a Company representative (compared to 65%
6 industry average).⁴

7 Thus, these survey results show that the Company's efforts in these areas are
8 producing favorable results.

9
10 **Q. The 2024 Customer Service Performance Report also shows that the Company's**
11 **performance in annual average call abandonment rate and in annual average percent**
12 **of calls answered within 30 seconds worsened in 2024. Could you please address the**
13 **Company's performance in those areas?**

14 **A.** On call abandonment rate and percentage of calls answered within 30 seconds, the Company
15 is taking several steps to improve its performance in that area. Specifically, the Company has
16 added internal and external resources, enhanced self-service functionality, delivered
17 additional training on call control and problem resolution, and increased focus on call
18 monitoring and quality reviews. The Company believes that with taking these steps, the
19 Company can improve its call abandonment rate.

20 As for calls answered within 30 seconds, I first note that the Company was the only
21 major electric utility in the Commission's report that does not include Interactive Voice

⁴ *Id.*, p. 19.

1 Response (“IVR”) calls in the calculations for this metric for 2024, per Commission guidance.
2 Inclusion of IVR would improve the Company’s metric and would result in 74% of calls being
3 answered within 30 seconds for 2024. That performance level is much more in line with other
4 Pennsylvania Electric Distribution Companies (“EDCs”). As the Commission states in its
5 report, “comparison of utilities across the industry is not valid” due to that reason.⁵
6 Nevertheless, PPL Electric consistently looks for ways to improve its performance in calls
7 answered within 30 seconds.
8

9 **Q. OCA Witness Alexander asserts that the Company did not include any testimony in its**
10 **filing that summarizes or addresses its customer service performance, its most recent**
11 **management audit, or performance metrics reported by the Commission. (OCA St. 7,**
12 **pp. 9, 21.) Please respond.**

13 A. In my direct testimony, I provided several details about the Company’s focus on customer
14 service, including the results of surveys on PPL Electric’s performance and various accolades
15 it has received for its customer service. (See PPL Electric St. No. 18, pp. 3-5.) I also explained
16 the customer service benefits of the Company’s IT upgrades. (See *id.*, pp. 5-6.) Although I
17 may not have referenced the Company’s most recent management audit or the Commission’s
18 reported performance metrics, I addressed the subject of the Company’s customer service
19 performance in my direct testimony.

20 Furthermore, at the time of preparing my direct testimony, the Commission’s 2024
21 Customer Service Performance Report was not available. That report was published in

⁵ *Id.*, p. 6.

1 December 2025. I did not believe that citing the Company's statistics from the 2023 Customer
2 Service Report, which was published in June 2024, would provide recent enough data to give
3 insights about the Company's current performance. However, as I noted previously, the 2024
4 Customer Service Report that has since been published shows that the Company is
5 outperforming its peers in many areas, and PPL Electric is keenly focusing on the areas where
6 it can improve.

7 As for the Commission's most recent Management and Operations Audit, the
8 Commission issued that report in June 2024 at Docket No. D-2023-3039488. In that report,
9 the Commission made three recommendations regarding the Company's customer service:
10 (1) "[i]mprove and strengthen customer service performance to at least pre-pandemic levels";
11 (2) "[c]ontinue outreach efforts to engage with payment delinquent customers and leverage
12 low-income resources to help reduce the overall level of outstanding customer balances"; and
13 (3) "[d]evelop internal controls for source data and reporting systems to ensure accuracy."⁶

14 The Company accepted all those recommendations and reported in July 2025 that the
15 Company's implementation of those recommendations was complete, ongoing, or both. PPL
16 Electric continues to implement those recommendations, which include the Company's
17 improvements in its customer service performance. Although more work needs to be done
18 with regard to the Company's call abandonment rate and its calls answered within 30 seconds,
19 PPL Electric has a plan and is well-positioned to improve its performance in those areas, as I
20 explained previously.

⁶ PPL Electric Utilities Corporation – Management and Operations Audit, p. 67 (June 2024), available at <https://www.puc.pa.gov/pcdocs/1837310.pdf>.

1
2 **Q. Ms. Alexander alleges that the Company “experienced a significant episode of billing**
3 **errors and metering errors when it changed its internal software in 2023” and that the**
4 **lack of an evidence-based discussion of customer service performance and a description**
5 **of how the Company complied with the settlement arising from the 2023 billing event**
6 **indicates a lack of priority associated with the statutory linkage between rates and**
7 **quality of service. (OCA St. 7, pp. 9-10.) Would you please respond?**

8 A. Ms. Alexander mischaracterizes the Company’s response to the 2023 billing event in several
9 significant ways. First, the billing event was not caused by a change in internal software;
10 rather, it was the failure of existing software programs. Second, PPL Electric reached a
11 voluntary settlement with I&E that included financial obligations on the Company, including
12 a \$1 million donation to Operation HELP (per the Commission’s modification to the
13 settlement changing it from a \$1 million civil penalty to the donation), and an agreement to
14 forgo cost recovery of \$16.2 million of event response costs in its next rate case, roughly a
15 4% decrease in the Company’s as-filed revenue requirement in this case. Finally, PPL Electric
16 was transparent with the Commission and stakeholders during the 2023 billing event. This
17 included regular meetings with OCA to keep them informed of the Company’s progress in
18 addressing the billing event. Nothing in the Company’s response to the 2023 billing event
19 would indicate that PPL Electric does not prioritize customer service or that the financial
20 impacts incurred by the Company were somehow insignificant.

1 **Q. Is there any question that the Company failed to comply with the Estimated Billing**
2 **Settlement that was approved as modified by the Commission?**

3 A. Absolutely not. In fact, the Company has complied with the terms of the settlement
4 agreement, including making the \$1 million contribution to Operation HELP. The Company
5 also did not make a claim to recover any of the \$16.2 million that PPL Electric incurred as
6 part of its response to the estimated billing event. The Company did not address compliance
7 with the 2023 billing event settlement in its direct testimony because it is not relevant to this
8 base rate case, which concerns the Company's proposed distribution base rate increase. To
9 the extent that the OCA questions the Company's compliance with the settlement, which
10 cannot reasonably be disputed, such issues would need to be resolved in a separate matter.

11
12 **Q. Ms. Alexander also raises issues with the Company's training materials, asserting that**
13 **they do not reflect current Pennsylvania policies and/or recent PPL Electric**
14 **commitments, particularly those commitments laid out in settlement agreements for the**
15 **Company's Default Service Plan ("DSP") V and DSP VI, which eliminate OnTrack**
16 **customers from participating in the retail electric supply market. (OCA St. 7, p. 13.)**
17 **Do you agree?**

18 A. No. PPL Electric's training materials contain information consistent with the Company's
19 agreement that it would return OnTrack customers to default service as part of the OnTrack
20 application process. Specifically, the Company's OnTrack Application – Live Agent
21 Reference Guide, pg. 13, details the process in which an OnTrack applicant is returned to
22 default service. This training material was provided in PPL Electric's response to CAUSE-

1 PA VI-19 Attachment 6. This information is also contained in the OnTrack Overview training
2 material, provided in CAUSE-PA VI-19 Attachment 5, pp. 101-102, and in CAUSE-PA VI-
3 19 Attachment 1. These training materials are used for internal and external call center
4 personnel. Copies of those training materials can be found in PPL Electric Exhibit LN-1R
5 [Answer to CAUSE-PA VI-19 and CAUSE-PA VI-19 Attachments 1, 2, 3, 4, and 6] and PPL
6 Electric Exhibit LN-15R (CONFIDENTIAL) [CAUSE-PA VI-19 Attachment 5
7 (CONFIDENTIAL)].
8

9 **Q. Ms. Alexander claims the Company's third party call center performance standards do**
10 **not ensure compliance with Chapter 56 and that PPL Electric has not adequately**
11 **audited, documented, or acted on vendor violations. (OCA St. 7, pp. 14-15.) Please**
12 **respond.**

13 A. PPL Electric disagrees with Ms. Alexander's assertions regarding the Company's
14 compliance oversight over its third-party call center operations. PPL Electric maintains
15 comprehensive compliance mechanisms designed to ensure adherence to all applicable
16 Commission regulations, including Chapter 56. The Company holds its third-party call
17 center staff to the same compliance standards as its in-house employees. These standards
18 are reinforced through training sessions, regular monitoring, and employee performance
19 reviews. When issues are identified, PPL Electric takes appropriate corrective action to
20 address them. This approach demonstrates the Company's commitment to regulatory
21 compliance and customer protection.
22

1 **Q. What recommendations does Ms. Alexander make based on these concerns with PPL**
2 **Electric’s training materials and third-party call centers?**

3 A. She recommends that the Company: (1) update vendor-provided training materials to reflect
4 current Pennsylvania policies and PPL Electric commitments; (2) conduct regular Chapter 56
5 compliance audits of call centers; (3) expand audits beyond complaint-based or
6 call-monitoring reviews to proactively identify problematic actions or transactions; (4)
7 include contract provisions allowing penalties tied to audit findings and Bureau of Consumer
8 Services (“BCS”) infractions; and (5) maintain audit documentation for discovery in future
9 base rate cases or complaint investigations.

10
11 **Q. Do you agree with these recommendations?**

12 A. I disagree with Items 1 through 4 and in part with Item 5. On Items 1 through 3, I previously
13 explained that the Company’s training materials do not need to be updated and that the
14 Company provides proper oversight of its call centers and takes corrective action when
15 needed. Therefore, I do not believe these recommendations are necessary. As for Item 4, the
16 Company’s contract with its call center vendor, IQor, does include penalty provisions for the
17 vendor not meeting certain performance metrics, but not specifically BCS infractions. The
18 contract with IQor runs through July 1, 2027, and the Company cannot negotiate additional
19 terms until it renews its agreement. Although I question the need to expand the penalty
20 provisions to include BCS infractions, the Company cannot do so as a practical matter until
21 the agreement reopens for negotiation pursuant to its terms. Lastly, I disagree in part with
22 Item 5. To the extent that the Company undertakes audits and investigations of its call center’s

1 performance and makes findings, PPL Electric will retain copies consistent with the
2 provisions of its record retention policy and applicable Commission rules. However, no
3 determination needs to be made now as to the discoverability of those documents in a future
4 base rate case, nor should the Company be required to undertake the audits and evaluations
5 proposed by Ms. Alexander.

6
7 **Q. Do you agree with Ms. Alexander's characterization of the Company's call center, IVR,**
8 **and planned smartphone app, including her claims that customer service will not**
9 **remain a priority after a rate increase and that customers should not have to choose**
10 **between automated and live-agent service (OCA St. 7, pp. 16-17)?**

11 A. I disagree with the notion that the Company will somehow prioritize customer service
12 performance less with these applications in place. Customer service remains a paramount
13 concern for the Company's operations with or without these technological applications.
14 Moreover, the Company's IT upgrades, the IVR system, and the smartphone application are
15 all designed with improvements in customer service and experience in mind. Indeed, with
16 respect to the IVR and smart phone application offerings, customers contact the Company
17 with a variety of issues, some of which can be handled effectively and efficiently through IVR
18 or a smartphone application. Having IVR and smartphone applications enables the live agents
19 to focus on customers with more complex inquiries. At the same time, PPL Electric can
20 improve its call center performance and be more efficient in its O&M expenditures by
21 relieving this stress off its call center. Thus, the Company's IVR and smartphone application

1 are designed to provide a better level of service for customers over a wide spectrum of needs,
2 including those who do not avail themselves of the IVR and smartphone application.

3
4 **Q. Ms. Alexander recommends that as a condition of any rate increase adopted by the**
5 **Commission, PPL Electric be required to conform to the average performance of other**
6 **Pennsylvania EDCs and that this performance should be supervised to achieve**
7 **regularity on a monthly basis. (OCA St. 7, pp. 18-19.) Do you agree?**

8 A. No. PPL Electric complies with the reporting requirements established by the Commission,
9 through its quality-of-service benchmarks and standards report. Additionally, other EDCs are
10 not required to perform to an average standard, so PPL Electric should not be singled out and
11 held to a different standard. Further, while benchmarking the Company's performance to its
12 peers can be helpful, there are certain unique characteristics in both operations and reporting
13 that could distort the comparison. For example, as I mentioned previously, PPL Electric is
14 the only major electric utility that did not include IVR calls in its 2024 data for calls answered
15 within 30 seconds, which the Commission acknowledged on page 6 of its 2024 Customer
16 Service Performance Report as making a comparison of utilities across the industry not valid.
17 Lastly, as Ms. Alexander notes in her testimony, PPL Electric's performance has improved.
18 This improvement is a direct result of the Company's ongoing efforts and continued focus on
19 improving the Company's customer service performance. Such efforts and focus will
20 continue even without additional reporting requirements.

21

1 **Q. Ms. Alexander similarly recommends that the Commission take PPL Electric’s actual**
2 **customer service performance and alleged deficiencies into account in the determination**
3 **of PPL Electric’s rate of return. (OCA St. 7, pp. 4-5, 21.) What is your response?**

4 A. I disagree with the notion that the Company’s customer service performance has been
5 deficient. As I laid out previously, PPL Electric has excelled in many areas of its customer
6 service. Also, the identified areas of improvement are top of mind for the Company, and PPL
7 Electric is well-positioned to improve its performance in those areas. On the whole, PPL
8 Electric has provided quality customer service to its customers and will continue to do so in
9 the future. Therefore, nothing with respect to the Company’s customer service should have
10 an adverse impact on the Company’s rate of return authorized in this proceeding.

11
12 **Q. Ms. Alexander argues that the fact that the Company has internal performance**
13 **standard goals is insufficient to justify any rate increase because there is no consequence**
14 **for a failure to achieve these objectives. (OCA St. 7, p. 19.) Please respond.**

15 A. PPL Electric does not have performance-based rates, and I am advised by counsel that Section
16 1330 of the Public Utility Code requires the establishment of a performance-based rate
17 mechanism to be accomplished through an application by the utility. See 66 Pa. C.S. §
18 1330(b)(1) (stating that “the commission may approve an application by a utility in a base rate
19 proceeding to establish alternative rates and rate mechanisms, including, but not limited to . .
20 . (ii) performance-based rates”). Moreover, the Company’s achievement of internal standard
21 goals can be evaluated in PPL Electric’s base rate cases, as Ms. Alexander and other witnesses
22 have had the opportunity to do in this case. Regardless, the Company places a strong emphasis

1 on achieving any performance goals that it sets out, and PPL Electric will continue to do so
2 even if performance-based rates are not in effect. In fact, PPL Electric can impose penalties
3 under its contract with the third-party call center if there are sustained performance issues.
4

5 **Q. Would you please respond to Ms. Alexander's contentions that PPL Electric does not**
6 **routinely conduct a root cause analysis of its customer complaints and that its only**
7 **analysis to date has been to identify common trends (OCA St. 7, p. 21)?**

8 A. I disagree with Ms. Alexander's suggestion that a root cause analysis is appropriate for every
9 situation. PPL Electric is not opposed to performing root cause analyses, and it does for major
10 issues. A recent example is the robust root cause analysis that the Company prepared in
11 response to the 2023 estimated billing event. However, for more routine areas that need
12 correction, it is more appropriate to address those issues with individual remedial training.
13 Additionally, the Company has a comprehensive training program to proactively address
14 issues before they arise. The Company endeavors to address customer complaints in a manner
15 that efficiently and effectively corrects the issue.
16

17 **Q. Please address Ms. Alexander's claims that the Company does not track and evaluate**
18 **the success or failure of its payment plans offered to residential customers and that the**
19 **increase in payment arrangement requests documented in a recent BCS report is a "red**
20 **flag." (OCA St. 7, p. 22.)**

21 A. Ms. Alexander mischaracterizes the Company's discovery response on this point. As support
22 for this claim, Ms. Alexander points to PPL Electric's answer to OCA VII-19 Attachment 1.

1 In her testimony, she states that the spreadsheet provided in response “provides a monthly list
2 of payment arrangement ‘counts’ but does not include any analysis of this data.” (OCA St. 7,
3 p. 22 n.33.) However, nothing in OCA VII-19 requested an analysis of the data. The
4 discovery request only asked the following: “Provide the monthly number of each type of
5 payment plans negotiated with Pennsylvania residential customers from January 2023 to the
6 present month.” (See PPL Electric Exhibit LN-2R [Answer to OCA VII-19 and OCA VII-19
7 Attachment 1].) That is exactly what PPL Electric provided in response. (*Id.*) Therefore, it
8 is clear that the Company tracks this information, given that PPL Electric was able to provide
9 the requested breakdown about its payment arrangements as part of that response.
10 Additionally, at no point does Ms. Alexander reference OCA VII-20, in which OCA did
11 request the Company’s “analysis of the success or failure associated with each or any of the
12 payment plans offered to residential customers.” (PPL Electric Exhibit LN-3R [Answer to
13 OCA VII-20].) In response, PPL Electric provided a comprehensive Excel workbook
14 providing the Company’s analysis of the payment arrangements’ outcomes. (See PPL Electric
15 Exhibit LN-16 [OCA VII-20 Attachment 1].) Thus, the Commission should reject any claim
16 that the Company does not track or evaluate the success of its payment arrangements.

17
18 **Q. Do you agree with Ms. Alexander that the Company’s training materials for service**
19 **termination and remote disconnection are deficient because they do not explicitly**
20 **require personal contact at the premises and do not include the customer rights and**
21 **protections required by the 2016 settlement (OCA St. 7, pp. 25-26)?**

1 A. No. The personal contact training is delivered to new field technicians verbally as part of their
2 onboarding. Additionally, the protections referenced by Ms. Alexander are listed on the door
3 hangers left by the field technicians when they are making personal contact before
4 termination. The content of the door hangers is also reviewed with the field technicians. PPL
5 Electric is complying with its obligations to provide personal contact prior to termination. I
6 would note that Ms. Alexander has not provided any evidence that PPL Electric is failing to
7 provide personal contact that would justify her recommendation for additional training
8 materials. Nevertheless, PPL Electric would be willing to revise its written training materials
9 to include personal contact requirements.

10
11 **Q. Please respond to Ms. Alexander's concern that there is not an internal compilation of**
12 **data associated with attempts at personal contact prior to the actual termination of**
13 **service, as well as her recommendations related to that concern. (OCA St. 7, pp. 28-29.)**

14 A. Ms. Alexander has failed to provide any evidence that PPL Electric has a deficiency in
15 providing personal contact prior to termination. Moreover, PPL Electric trains and requires
16 its representatives to attempt personal contact before termination, as required by the
17 Commission's regulations. The Company has records of the telephonic personal contact
18 attempts prior to the termination. Given that the field representatives are trained to provide
19 personal contact at the time of termination, the record of the termination occurring serves as
20 the record that the personal contact was attempted. Also, in my review of recent customer
21 complaints, I did not see any specific complaints around the Company failing to provide
22 personal contact prior to termination. As such, the Company does not see the need to

1 undertake the time, effort, and expense to compile data on those contacts, and I reject Ms.
2 Alexander's recommendations on this issue.

3
4 **Q. Ms. Alexander recommends that PPL Electric: (1) confirm that its practices and CSR**
5 **training align with DSP V and DSP VI commitments; (2) update its policies and**
6 **procedures in rebuttal; (3) exclude low-income customers from the retail market if they**
7 **are included in the bill-impact analysis; and (4) increase outreach to warn customers**
8 **about potential higher EGS charges and how to respond. (OCA St. 7, pp. 31-32.) Please**
9 **respond.**

10 A. With respect to PPL Electric's commitments in DSP V and DSP VI to disallow OnTrack
11 customers from shopping, I have previously stated that the Company is in compliance with
12 those requirements and has appropriate training. As for excluding low-income customers
13 from shopping for competitive electric generation supply service, I am advised by counsel
14 that PPL Electric lacks the authority to do so regardless of whether it would have benefits for
15 those customers. From the Company's perspective, legislative change would be required for
16 PPL Electric to prohibit all low-income customers from shopping. Finally, PPL Electric
17 makes significant outreach efforts to its customers to educate them on shopping. Specifically,
18 the Company has a "Shop Smart" section on its website to educate customers, and PPL
19 Electric provides outreach emails twice a year around Price to Compare ("PTC") changes
20 reminding customers to check their supply rates.

1 **Q. CAUSE-PA Witness Cicero argues that the Company’s payment arrangement**
2 **standards are ineffective and need more flexibility. He also raises concerns about the**
3 **IVR process and how customers seeking payment arrangements are referred to**
4 **OnTrack, which is PPL Electric’s Customer Assistance Program (“CAP”), and to other**
5 **universal service programs. (CAUSE-PA St. No. 1, pp. 98-102.) What**
6 **recommendations does he make to address his concerns?**

7 **A.** Mr. Cicero recommends that PPL Electric: (1) revise payment-arrangement policies to
8 consider customers’ vulnerabilities and their ability to pay; (2) replace formulaic
9 arrangements with household-specific terms based on successful past arrangements; (3) adjust
10 guidelines to give additional time to victims of domestic violence and customers with medical
11 certificates; and (4) place a hold on accounts with pending CAP applications to prevent
12 unnecessary terminations. (CAUSE-PA St. No. 1, pp. 103-04.)

13
14 **Q. Please respond to his concerns and recommendations.**

15 **A.** First, I disagree with Mr. Cicero’s recommendation regarding the Company’s flexibility to
16 enter payment arrangements (see Items 1 through 3 above). The Company already considers
17 the factors set forth in Section 56.97(b) of the Commission’s regulations when determining
18 the payment arrangements to offer customers. Those factors are: (1) “size of the unpaid
19 balance”; (2) “the ability of the customer to pay”; (3) “the payment history of the customer”;
20 and (4) “the length of time over which the bill accumulated.” 52 Pa. Code § 56.97(b). The
21 additional factors proposed by Mr. Cicero are not set forth in Section 56.97(b) and could lead
22 to the Company offering inconsistent payment arrangements to similarly situated customers.

1 Given the Company's obligation not to engage in unreasonable discrimination in rates or
2 service for customers in the same customer class,⁷ PPL Electric is concerned that adding more
3 subjectivity to the payment arrangement terms that are offered could expose the Company to
4 potential regulatory liability. Moreover, if the Commission wants to require that additional
5 factors be considered when establishing payment arrangements, PPL Electric believes it
6 would be more appropriate to address changes to those factors in a rulemaking proceeding to
7 modify Section 56.97(b), as opposed to this individual base rate proceeding that only affects
8 the Company. Also, I will note that the addition of more factors and subjectivity to the
9 payment arrangement analysis could further delay the establishment of such agreements.
10 Right now, customers can set up payment arrangements through an automated process, after
11 providing their household income and number of household occupants. This efficient process
12 would be hampered by changes to the factors that PPL Electric must consider in establishing
13 payment arrangements.

14 Second, I disagree with Mr. Cicero's recommendation that PPL Electric place a 15-
15 day hold on a customer's account when they apply for CAP. Mr. Cicero says that this hold
16 would "allow customers to apply for and enroll in PPL's CAP without experiencing a service
17 termination while their applications are pending" and that the hold would "encourage
18 customers to apply for PPL's CAP before they are placed in an unaffordable payment
19 arrangement which are often unsuccessful." (CAUSE-PA St. No. 1, p. 73.) However, under
20 the Company's current processes, an initial referral to OnTrack creates a Suspend Charge
21 (hold) on the account for 21 days to allow the customer time to apply. Subsequent referrals

⁷ See 66 Pa. C.S. §§ 1304, 1502.

1 within one year are marked “Recurring” and only create a one-day suspend on the account. I
2 do not believe it is appropriate to layer on a 15-day hold any time a CAP application is
3 submitted, as proposed by Mr. Cicero. Indeed, not all CAP applications are successful, with
4 approximately 34% of applications being denied. Therefore, I believe that there is an
5 unfortunate potential for customers to misuse the 15-day hold under Mr. Cicero’s proposal,
6 such that they submit CAP applications they know will be denied simply to have a 15-day
7 hold placed on their account. Mr. Cicero also does not propose any limits on the number of
8 times that the 15-day hold could be instated on a customer’s account, which creates more
9 uncertainty for this recommendation’s implementation and potential for misuse by customers.
10 Furthermore, the Company has a responsibility to help limit the balances in arrears on
11 customers’ accounts, as those costs are ultimately passed onto other ratepayers in the form of
12 uncollectible expenses when collections efforts fail. I am concerned that Mr. Cicero’s
13 proposal would exacerbate the arrears on customers’ accounts, as they could file a CAP
14 application to put a hold on their account instead of making a payment or entering a payment
15 arrangement to continue or restore service.

16
17 **Q. Mr. Cicero also raises issues with the Company’s policies for medical certificates. What**
18 **are they?**

19 A. He asserts that PPL Electric’s call scripts do not clearly explain payment obligations during
20 active medical certificates, that its process for submitting medical certificate forms is too
21 restrictive, and that its bills do not adequately inform customers with active medical

1 certificates of their payment responsibilities. He also claims PPL does not offer sufficiently
2 flexible payment arrangements for these customers. (CAUSE-PA St. No. 1, p. 105.)
3

4 **Q. What does he recommend?**

5 A. He recommends that PPL Electric: (1) update call scripts and training to clearly explain
6 medical-certificate renewal rules; (2) provide customers with the certificate form or
7 instructions for downloading it; (3) add a website link to the Commission's standard form
8 and accept it; (4) revise scripting to explain that certificates may be submitted via form or
9 qualifying letter; (5) revise bills for customers with active certificates to show required
10 current-charge payments and present draft changes to the Universal Service Advisory
11 Committee ("USAC"); and (6) implement all reforms within 120 days of the
12 rate-implementation date. (CAUSE-PA St. No. 1, pp. 108-09.)
13

14 **Q. Do you agree with his concerns and recommendations concerning the Company's**
15 **medical certificates?**

16 A. I disagree with Mr. Cicero's concern that the Company's call scripting fails to accurately and
17 adequately inform customers about payment requirements with active medical certificates.
18 PPL Electric's customer service representatives are trained on the Commission's
19 requirements governing medical certificates and are required to relay that information to
20 customers during contacts about billing and termination issues. Such information includes
21 informing customers that they can renew medical certificates past two if they keep up with
22 their current charges. The Company needs to balance the amount of information presented to

1 customers in order to inform them of available assistance while not overwhelming them with
2 program details. The recommended scripting changes from Mr. Cicero are not required and,
3 in the Company's opinion, would add little value to helping customers understand their
4 options with respect to medical certificates.

5 Likewise, I disagree that that the Company's process for customers to submit medical
6 certificate forms is improperly restrictive. PPL Electric provides information and the medical
7 certificate form to customers through a variety of methods, including on its website and by
8 email to interested customers. Moreover, the Company's website provides a link for
9 customers to download a copy of the Commission's standard medical certificate form.
10 Therefore, Mr. Cicero's concern and related recommendation lack merit because customers
11 seeking medical certificates are already "provided with a medical certificate form by PPL or
12 instructed how to download the form from PPL or the Commission's website, rather than the
13 customer's medical provider having to reach out to obtain this form." (CAUSE-PA St. No.
14 1, p. 108.)

15 Lastly, I disagree with Mr. Cicero's proposal to modify the Company's monthly bill
16 for customers with active medical certificates. PPL Electric's bills provide all the information
17 required under the Commission's regulations, including 52 Pa. Code § 56.15. Nothing in
18 those regulations, to my knowledge, requires the Company to provide the information
19 proposed by Mr. Cicero.

20 I am also concerned that Mr. Cicero's billing proposal has the potential to increase
21 customer confusion around medical certificates. Unless the 30-day postponement period lines
22 up exactly with the end of the billing period, there will be a disconnect between when the

1 medical certificate is active and when the billing period ends. This is important because under
2 Mr. Cicero's proposal, you could have a customer whose medical certificate postponement
3 period ends on the day before the billing period ends, in which case the Company would need
4 to make a manual adjustment to ensure that the customer does not receive the specially tailored
5 bill for customers with active medical certificates. Conversely, if the Company receives a
6 medical certificate on the same day as the date that the bill is generated, PPL Electric would
7 have to make a manual adjustment to ensure that the medical certificate bill is generated
8 instead.

9 Further, I believe Mr. Cicero fails to understand the practical limitations of his billing
10 proposal and the costs needed to implement it. Any new billing process, including the bill
11 modifications and creation of a manual process, will take time and money to develop. Each
12 of these proposals would take approximately 6 months to complete and with each costing
13 approximately \$250,000 to \$350,000.

14
15 **Q. Certain issues were raised at the public input hearings concerning the Company's**
16 **customer service, as noted by OCA Witness Wise. (OCA St. 9, pp. 18-20.) Could you**
17 **please respond to those allegations?**

18 A. Yes. OCA Witness Wise asserts that "[e]ight customers testified regarding their
19 dissatisfaction with PPL's customer service, describing repeated delays in equipment
20 replacement, insufficient vegetation management, unreliable electrical service, and persistent
21 billing issues that have negatively impacted them." (OCA St. 9, p. 18.) Other witnesses will
22 address certain of these allegations, but I do want to respond to some of them here as well.

1 First, as I explained previously, the 2024 Customer Service Performance Report
2 shows that the Company has achieved great marks in customer satisfaction, especially with
3 respect to its field representatives' visits to customers' premises, where 83% and 94% of
4 surveyed customers reported satisfaction that the field representatives responded promptly
5 and completed their work in a timely manner, respectively.⁸

6 Second, Ms. Wise points to the testimony of Ms. Terece Cyrus, who alleged that her
7 bills are being estimated by the Company because the usage keeps increasing, that she had
8 trouble reaching PPL Electric due to long wait times, and that she was forced to enter PPL
9 Electric's budget billing program. PPL Electric reviewed Ms. Cyrus's account and confirmed
10 that she is not being rendered estimated bills. Also, contrary to her testimony, her electric
11 usage has actually decreased, not increased, over the past three years. As for her call wait
12 times, the Company reviewed Ms. Cyrus' account and the last time she contacted the
13 Company was during the 2023 billing event which explains the long wait times. However, as
14 I noted previously, PPL Electric is actively working to improve its performance in the calls
15 answered within 30 seconds. Further, no customer, including Ms. Cyrus, is forced to enter
16 into the Company's budget billing program. Such participation is entirely voluntary. PPL
17 Electric did contact Ms. Cyrus and explained the decrease in her electric usage and her
18 enrollment in budget billing. PPL Electric's understanding is that Ms. Cyrus now understands
19 her usage history and wants to remain enrolled in budget billing. Notwithstanding, if Ms.
20 Cyrus or any customer no longer wants to participate in budget billing, they can contact the
21 Company to unenroll.

⁸ 2024 Customer Service Performance Report, p. 24.

1 Third, Ms. Wise highlights the testimony Mr. James Robert, who testified that “PPL
2 cannot be trusted to do something even when ordered by the Commission” and referenced the
3 Settlement approved and modified in the estimated billing investigation at Docket No. M-
4 2023-3038060. As I explained previously in response to OCA Witness Alexander, there is
5 no question that PPL Electric complied with the requirements of that Settlement.
6

7 **Q. EJA Witness Rábago makes the assumption that 17% of customer service calls involve**
8 **starting service or grid connections but speculates the true share is likely lower given**
9 **PPL Electric’s slow growth. (EJA St. No. 1, p. 64.) Is that an accurate statement about**
10 **the Company’s customer service call volume?**

11 **A.** No. Mr. Rábago’s contention lacks merit. Based on PPL Electric’s data, approximately 9%
12 of the Company’s customer service call volume in 2025 related to turning on service and
13 connecting customers to the distribution system. Further, Mr. Rabago said in discovery that
14 this contention was based on his experience and expertise, but PPL Electric’s actual data
15 contravenes his opinion. (See PPL Electric Exhibit LN-4R [EJA Answer to PPL to EJA-III-
16 1].)
17

18 **III. LOW-INCOME CUSTOMER ISSUES**

19 **Q. Before addressing some allegations in more detail, could you please provide an overview**
20 **of the Company’s efforts to enroll low-income customers in its assistance programs to**
21 **help them reduce their electric bills and the Company’s successes on that front?**

1 A. PPL Electric offers a series of assistance programs to customers through both its Commission-
2 approved Universal Service and Energy Conservation Plan (“USECP”) and Phase IV Energy
3 Efficiency and Conservation (“EE&C”) Plan. Under the USECP, the Company offers four
4 programs: (1) OnTrack, which is the Company’s CAP, a special payment program for
5 payment troubled low-income households at or below 150 percent of the Federal Poverty
6 Income Guidelines (“FPIG”); (2) WRAP, which is the Company’s Low Income Usage
7 Reduction Program (“LIURP”) and helps customers reduce their electric bills and improve
8 comfort through weatherization measures; (3) Operation HELP, which is a hardship fund
9 supporting low-income customers who have overdue balances and an inability to pay the full
10 amount of their electric bill, and is funded primarily by donations from the Company, and
11 supplemented by voluntary donations by the Company and PPL Corporation employees,
12 retirees, and customers; and (4) CARES, which is a special referral service that provides
13 credits to help pay electric bills for customers with temporary hardships, such as illness,
14 injury, loss of job, or high medical bills, and also directs customers to additional programs
15 and services offered by various agencies or PPL Electric. Additionally, PPL Electric’s
16 Commission-approved Phase IV EE&C Plan offers a Low-Income Program, which provides
17 various energy efficiency and conservation measures to eligible low-income customers, at no
18 direct cost to them. These EE&C Plan low-income measures are designed to help reduce low-
19 income customers’ energy usage and, by extension, their electric bills.

20 PPL Electric is proud of these programs and its dedicated teams that are tasked with
21 implementing them. For example, PPL Electric continues to see improvements in its CAP
22 participation rates, with the average monthly CAP enrollment of 67,491 customers in 2022

1 increasing to 74,564 customers in 2024, as noted in the Commission’s 2024 Universal Service
2 Report that was recently released in January 2026.⁹

3 The Company’s CAP participation rate, which is the monthly average number of
4 customers enrolled in CAP divided by the number of confirmed low-income customers, was
5 35.4% in 2024, up from 33.9% in 2022.¹⁰ PPL Electric looks to build on these successes
6 going forward.

7
8 **Q. Will the enrollment of those customers in the universal service programs help make**
9 **their bills more affordable and help insulate those customers from the impact of the**
10 **proposed base rate increase?**

11 A. Yes. OnTrack, or the Company’s CAP, can play a significant role in particular. Specifically,
12 OnTrack’s payment plan design is based around three payment options: (1) the Percent of
13 Income (“PIP”) option; (2) Average Bill; and (3) the Minimum Payment option. For each
14 OnTrack participant, PPL Electric evaluates whether the PIP option or the Average Bill option
15 will offer the best solution for the customer’s situation. Under the PIP option, customers only
16 pay a certain percentage of their household income based on the factors set forth in the
17 Company’s USECP. Therefore, CAP participants whose payments are based off the PIP
18 option will not see their monthly payment amounts increase if the Commission grants PPL
19 Electric’s proposed base rate increase. Additionally, the Company’s other assistance

⁹ Universal Service Programs & Collections Performance – 2024 Report, p. 56 (Jan. 2026), available at <https://www.puc.pa.gov/media/3771/2024-universal-service-report-final.pdf>.

¹⁰ See *id.*

1 programs offer opportunities for customers to reduce their energy usage and electric bills,
2 which can help mitigate the impact of the proposed base rate increase.

3
4 **Q. Other parties' witnesses reference, among other things, information on Asset Limited,**
5 **Income Constrained, Employed ("ALICE") data and the Self-Sufficiency Standard.**
6 **(See, e.g., OCA St. 8, pp. 18-28; EJA St. No. 1, pp. 11-12; CAUSE-PA St. No. 1, pp. 34-**
7 **35.) Do you have any comment on that data?**

8 A. Yes. While ALICE and Self-Sufficiency Standard tools can be useful in providing
9 socioeconomic context, they are not the Commission's governing affordability metrics and
10 are not incorporated in Commission's CAP Policy Statement or regulations. A change to
11 make low-income assistance program eligibility based on ALICE versus Federal Poverty
12 Guidelines is a larger regulatory discussion, appropriate for a Commission-initiated statewide
13 proceeding, not an individual utility's base rate proceeding.

14
15 **Q. OCA Witness Colton makes a series of recommendations regarding confirmed low-**
16 **income customers. (OCA St. 8, pp. 4-5, 47-54.) Could you please summarize them?**

17 A. Mr. Colton recommends expanding how PPL Electric identifies confirmed low-income
18 ("CLI") customers by: (1) accepting the same documentation used for deposit exemption
19 eligibility; (2) treating anyone who received a Low Income Home Energy Assistance Program
20 ("LIHEAP") grant in the current or prior two years as CLI; (3) allowing customers removed
21 from CAP for failure to recertify to retain CLI status for 12 months; (4) postponing
22 disconnection for CLI customers who wish to apply for CAP until the application is

1 completed; and (5) requiring PPL Electric to give CLI customers a plain language notice—
2 before entering a payment arrangement—explaining CAP, arrearage forgiveness benefits, and
3 ensuring customers knowingly choose between CAP and a deferred payment arrangement
4 (“DPA”). (OCA St. 8, pp. 4-5.)

5
6 **Q. What are your responses to these recommendations?**

7 **A.** I disagree with Mr. Colton’s recommendations.

8 As to his first, second, and third recommendations concerning how the Company
9 defines “confirmed low-income customers,” Company’s confirmed low-income
10 identification process is consistent with Commission regulations and the CAP Policy
11 Statement. PPL Electric accepts multiple forms of verification, including verbal income
12 verification, LIHEAP confirmation, and OnTrack enrollment. These methods align with 52
13 Pa. Code § 56.32(e), which permits utilities to rely on income documentation or other
14 reasonable indicators. Although Mr. Colton suggests expanding “confirmed low-income” to
15 include proxies such as SNAP or multi-year LIHEAP lookbacks, such changes raise data
16 privacy and accuracy concerns and should be addressed through the USECP proceeding
17 instead of a base rate proceeding. I further note that PPL Electric is actively pursuing
18 enhancements, including leveraging Pennsylvania Department of Human Services (“DHS”) data-sharing
19 agreements, to broaden identification of confirmed low-income customers responsibly. Additionally, CAP
20 recertification is required under the Commission’s CAP Policy Statement to ensure program integrity and proper targeting of benefits. The Company
21 provides multiple reminders—emails, texts, robocalls, and web prompts—during the
22

1 recertification window. The Company also recently added self-service recertification tools
2 and proactive outreach to reduce attrition. PPL Electric will continue to evaluate
3 recertification processes through stakeholder engagement but does not agree that current
4 practices are ineffective; rather, they reflect regulatory requirements and customer
5 responsibility.

6 As for his fourth recommendation, I disagree with a process to postpone disconnection
7 of service while a customer applies for CAP. As I stated regarding a similar proposal by
8 CAUSE-PA Witness Cicero, I believe that there is an unfortunate potential for customers to
9 misuse the postponement, such that they submit CAP applications they know will be denied
10 simply to have the disconnection postponed. Like Mr. Cicero, Mr. Colton also does not
11 propose any limits on the number of times that the postponement could be instated on a
12 customer's account, which creates more uncertainty for this recommendation's
13 implementation and potential for misuse by customers. Furthermore, the Company has a
14 responsibility to help limit the balances in arrears on customers' accounts, as those costs are
15 ultimately passed onto other ratepayers in the form of uncollectible expenses when collections
16 efforts fail. I am concerned that Mr. Colton's proposal would exacerbate the arrears on
17 customers' accounts, as they could file a CAP application to put a hold on their account instead
18 of making a payment or entering a payment arrangement to continue or restore service.

19 Lastly, regarding his fifth recommendation, Mr. Colton misunderstands PPL
20 Electric's process. The Company informs every customer of its assistance programs,
21 including OnTrack, when a customer requests a payment arrangement. The payment

1 arrangement process does not prevent a customer from applying for OnTrack. Rather, the
2 payment arrangement process complements the application process for OnTrack..

3
4 **Q. OCA Witness Colton and CAUSE-PA Witness Cicero also make several**
5 **recommendations concerning the Company's treatment of cash security deposits.**
6 **(OCA St. 8, pp. 5-6, 54-60.) What are those recommendations?**

7 A. Mr. Colton recommends four deposit-related changes: (1) amend PPL Electric's tariff to
8 broaden low-income deposit exemptions and require staff to ask applicants if they can provide
9 income information; (2) refund deposits to all customers classified as Confirmed
10 Low-Income; (3) review all existing deposits within three months, refund those qualifying for
11 exemptions, and report results to BCS and the USAC; and (4) limit PPL Electric's discretion
12 over how deposits are refunded and require customer consent before applying deposits as bill
13 or arrearage credits. (OCA St. 8, p. 5.)

14 Similarly, Mr. Cicero recommends that PPL Electric adopt a more flexible
15 security-deposit policy by allowing customers to self-attest to income without additional
16 verification. He also proposes giving CAP-eligible customers the choice to have
17 previously-assessed deposits refunded or applied to their bills, and prohibiting the application
18 of deposits to arrears eligible for CAP forgiveness without the customer's affirmative consent.
19 Finally, he recommends updating related policies, procedures, training, and customer
20 communications within 120 days of the rate-effective date. (CAUSE-PA St. No. 1, pp. 123-
21 27.)

1 **Q. Do you agree with these recommendations?**

2 A. No, the Company does not agree with these recommendations. First, PPL Electric’s tariff and
3 practice for security deposits complies with 52 Pa. Code § 56.32(e). As outlined in the
4 regulation, the Company exempts low-income customers participating in CAP and LIHEAP.

5 Second, customers not participating in the program have the option to provide their
6 income information to have the deposit waived. Mandating additional steps that are not
7 required by regulation imposes operational burdens without likely improvement to outcomes.

8 Third, waiving all deposits for confirmed low-income customers is overly broad and
9 not consistent with Commission practice. Further, the costs associated with the waiver of
10 such deposits also are not reflected in the Company’s base rate case filing. Without such costs
11 being reflected in the Fully Projected Future Test Year (“FPFTY”), PPL Electric’s revenue
12 requirement would be understated.

13 Finally, PPL Electric’s current refund practices are consistent with Commission rules.
14 Deposits are applied as credits to the account unless the customer requests otherwise. Also,
15 while Mr. Colton suggests requiring “informed consent” before applying a deposit to arrears
16 and Mr. Cicero proposes that customers be provided the choice of whether to apply the deposit
17 to arrears or not,¹¹ neither of these proposals is mandated by regulation. Moreover, the
18 Company’s approach ensures timely crediting of customer accounts and minimizes confusion.

19 In summary, PPL Electric’s tariff and practices comply with Chapter 56 and
20 Commission policy. Mr. Colton’s and Mr. Cicero’s proposed changes would add complexity
21 without measurable benefit and should be rejected.

¹¹ OCA St. 8, p. 52.

1
2 **Q. OCA Witness Colton also proposes a series of “outcome metrics” that the Commission**
3 **should impose on PPL Electric to measure the Company’s “performance on**
4 **affordability outcomes,” with “respect to its credit and collection outcomes in**
5 **particular.” (OCA St. 8, pp. 78-87.) What are those outcome metrics?**

6 A. There are two outcome metrics that Mr. Colton proposes: the first is tied to increasing the
7 average monthly enrollment of low-income customers in CAP, and the second is tied to
8 monthly average CAP participation. (OCA St. 8, pp. 80-82.)

9 His first outcome metric recommends that PPL Electric increase OnTrack enrollment
10 by 5% in the first program year compared to the 2024–2025 base year, 3% in the second year,
11 and 2% in the third year, stating that these targets mirror metrics recently adopted by the New
12 Jersey Board of Public Utilities (“NJBPU”). He also proposes a second metric consisting of
13 four annual 10% reductions over three years: the number of defaulted payment arrangements,
14 the number of residential nonpayment disconnections, the number of customers disconnected
15 since April 1 who remain without service as of December 1, and the total arrears and
16 payment-agreement balances considered “money at-risk” to the Company. (OCA St. 8, pp.
17 82-83.)
18

19 **Q. What initial concerns do you have with Mr. Colton’s proposed outcome metrics?**

20 A. Mr. Colton is effectively attempting to promulgate new regulatory standards and impose them
21 on PPL Electric outside of a Commission-initiated rulemaking. No statutes, regulations,
22 policy statements, or Commission orders require or support the two outcome metrics that Mr.

1 Colton is attempting to impose upon PPL Electric in this case. If adopted, as part of this
2 proceeding, these outcome objectives would only apply to the Company. If that happens, PPL
3 Electric would be subject to regulatory standards different than those applied to every other
4 EDC in Pennsylvania. However, all EDCs in Pennsylvania should be evaluated under the
5 same regulatory standards. Notably, Mr. Colton states that he based the first outcome metric
6 on standards recently adopted by the NJBPU for electric and natural gas utilities. (See OCA
7 St. 8, p. 82.) In that respect, all the electric and natural gas utilities are subject to those
8 standards, as opposed to them being forced upon a single utility through a base rate
9 proceeding. Therefore, consistent with the NJBPU standards upon which Mr. Colton relies,
10 Mr. Colton's proposal should be raised, if at all, within the context of a statewide rulemaking
11 proceeding which would permit participation from all stakeholders.

12 Second, as noted by PPL Electric Witness Bethany Johnson (PPL Electric St. No. 5-
13 R), the Commission should reject Mr. Colton's performance-based rate mechanism that
14 would be based on the Company's performance under these proposed outcome metrics. Only
15 PPL Electric can propose performance-based rates in a future base rate case, and such
16 alternative ratemaking mechanisms cannot be forced onto the Company by the OCA.
17 Additionally, while Mr. Colton relies heavily on the NJBPU for purposes of his first outcome
18 metric, he fails to recognize that the NJBPU did not couple its "enrollment targets" with any
19 performance-based rates. See *In the Matter of a Rate Design and Policy Study Regarding*
20 *Driving Equity in the Clean Energy Transition*, Docket No. QO24110853, p. 17 (NJBPU
21 Order dated June 18, 2025) ("*NJBPU Order*"). The NJBPU did not even state that utilities'
22 failure to achieve the targets would result in any adverse rate findings. (See *id.*) Instead, the

1 NJBPU stated that it “may consider Utility achievement of enrollment targets when reviewing
2 future cost recovery for administration of [Universal Service Fund (‘USF’)] application intake
3 activities.” (*Id.*) Thus, the Commission should reject any suggestion by Mr. Colton that his
4 proposed outcome objectives can and should form the basis of performance-based rates in the
5 future.

6 Third, it is wholly inappropriate to set required targets subject to penalty without any:
7 (1) detailed analysis of whether Company can actually achieve these targets; and (2) any
8 quantification of the increased capital costs and O&M expenses that PPL Electric would incur
9 in order to achieve those targets. To provide a comparison from the Act 129 EE&C Plan
10 context, the Commission’s Statewide Evaluator (“SWE”) undertakes a comprehensive
11 analysis of the energy efficiency and peak demand reduction potential in each EDC’s service
12 territory before the Commission establishes the required energy savings and peak demand
13 reduction targets it believes are reasonably achievable within the EDC’s budget. These
14 analyses are critical because an EDC’s failure to achieve those targets would subject the EDC
15 to significant penalties.

16 Mr. Colton’s approach appears to skip this necessary step. When asked in discovery
17 for his analyses about how the first outcome metric is actually achievable, Mr. Colton simply
18 cited the Bureau of Consumer Services’ (“BCS”) Report on Universal Service Programs and
19 Collections Performance. (*See* PPL Electric Exhibit LN-5R [OCA Answer to PPL to OCA-
20 III-4(f)].) When asked the same question about his second outcome metric, Mr. Colton
21 pointed to that same BCS Report as well as the Commission’s Cold Weather Survey. (*See*
22 PPL Electric Exhibit LN-6R [OCA Answer to PPL to OCA-III-5(c)]). No actual analyses,

1 however, were provided.

2 On top of that, Mr. Colton gives no consideration to the increased costs that the
3 Company would have to incur to achieve the targets and avoid the substantial ROE penalties
4 under his proposal. In fact, he confirmed in discovery that he “has not performed such a
5 calculation” about the increased O&M expenditures that would be required for PPL Electric
6 to achieve his proposed outcome metrics. (PPL Electric Exhibit LN-7R [OCA Answer to
7 PPL to OCA-III-6(a)].)¹² By comparison, the NJBPU, upon which Mr. Colton bases his first
8 outcome metric, specifically authorized the utilities, “[w]ith respect to Utility USF
9 administrative cost recovery,” to “petition the Board for authority to defer costs.” *NJPBU*
10 *Order*, p. 18. Thus, Mr. Colton’s outcome metric proposal is fatally flawed.

11 Finally, I note that Mr. Colton has proposed similar outcome metrics in several
12 proceedings before this Commission. He even summarized some of his recommended
13 outcome metrics in prior proceedings in his testimony before the Connecticut Public Utilities
14 Regulatory Authority (“PURA”) in the United Illuminating Company’s 2022 base rate case
15 at Docket No. 22-08-08. (See PPL Electric Exhibit LN-9R [PPL-OCA-1-32- RDC FINAL
16 Direct –UI CT –rates, Appx. 2].) To the best of my knowledge, the Commission has never
17 adopted Mr. Colton’s proposed outcome metrics in a fully litigated base rate case proceeding.
18

19 **Q. What other concerns do you have?**

20 **A. From my perspective, it is inappropriate to penalize the Company for failing to achieve**

¹² Mr. Colton also cannot guarantee that if the Company were to do “an exemplary job of achieving the outcomes” he has identified, he would not oppose the Company seeking an upward adjustment to its return on equity in its next base rate case. (PPL Electric Exhibit LN-8R [OCA Answer to PPL to OCA-III-7(b)].)

1 outcome metrics that even Mr. Colton concedes are not within PPL Electric's direct control.
2 (OCA St. 8, p. 84.) Although Mr. Colton asserts that these metrics are appropriate because
3 the Company has "influence" in being able to achieve them, Mr. Colton's proposal essentially
4 dismisses whether PPL Electric actually can achieve these outcomes within its existing or
5 even increased budgets, as noted previously. This is especially concerning given that the
6 achievement of the first outcome metric: (1) will be dependent on customers voluntarily
7 deciding whether to enroll in PPL Electric's CAP; and (2) will have an impact on the budget
8 required for the Company's CAP set forth in its Commission-approved USECP. Indeed, the
9 Company can encourage but cannot force customers to enroll in CAP. Yet, Mr. Colton would
10 seek to penalize the Company, even if PPL Electric devotes a significant amount of time,
11 effort, and expense to encourage customers to enroll only for those customers to decide that
12 they do not want to do so. Also, I maintain that changes to the Company's Commission-
13 approved budget for its USECP programs, including CAP, should be addressed in the USECP
14 proceeding, instead of this base rate proceeding.

15 Further, the achievement of Mr. Colton's second outcome metric can be inherently
16 contradictory, as Mr. Colton appears to recognize. (See OCA St. 8, pp. 83-84.) For example,
17 take Mr. Colton's proposed "reduction by 10% each year for three years in the absolute
18 number of defaulted residential deferred payment arrangements." (OCA St. 8, p. 82.) PPL
19 Electric could try to reduce the number of defaulted residential deferred payment
20 arrangements by offering customers payment arrangements with 20-year terms, thereby
21 reducing the monthly payment significantly, assuming *arguendo* that such payment
22 arrangements would be deemed lawful by the Commission. While that may make it easier

1 for customers to make payments, there is no guarantee that the customers would still make
2 timely payments. Also, the monthly payment amount is dependent on the term of the payment
3 arrangement and the total amount of arrears, so a reduced monthly payment due to an
4 elongated payment arrangement term would consequently have less of an impact on reducing
5 the total amount of arrears on customers' accounts.

6 Similarly, Mr. Colton seeks to force PPL Electric to reduce by 10% each year the
7 absolute number of residential nonpayment disconnections and the number of residential
8 customers who have had their service disconnected for nonpayment and who remain in their
9 home with service not yet reconnected. (See OCA St. 8, p. 82.) PPL Electric could try to
10 reduce these numbers by terminating fewer customers for nonpayment. However, as even
11 Mr. Colton recognizes, that could exacerbate the total amount of arrears on customers'
12 accounts.

13 Nevertheless, Mr. Colton also would require that PPL Electric reduce by 10% each
14 year for three years the "money at-risk to the Company," i.e., "the sum of money owed by
15 customers in arrears and the money owed by customers on deferred payment arrangements."
16 (OCA St. 8, p. 83.) Therefore, it is extremely likely that PPL Electric's actions to achieve one
17 of the first three facets of the second outcome metric would result in the Company failing to
18 achieve the fourth facet of the metric.

19
20 **Q. Does Mr. Colton provide any ideas for how to achieve the second outcome metric?**

21 A. He suggests PPL Electric could focus outreach on the lowest-income customers, pair payment
22 assistance with energy-efficiency programs, and coordinate utility-funded assistance outreach

1 with LIHEAP. He adds that management should determine which strategies to pursue, with
2 regulators evaluating only the results. (OCA St. 8, p. 84.)

3
4 **Q. Do you believe Mr. Colton's ideas are realistic ways to achieve the second outcome**
5 **metric?**

6 A. Absolutely not. PPL Electric already conducts targeted outreach to enroll customers in its
7 CAP and other assistance programs. Any additional targeted outreach will necessarily require
8 an increased budget for those Commission-approved programs, which, as I explained before,
9 is outside the scope of this base rate proceeding. That increased budget also would increase
10 the amount of universal service costs that are recovered through the Universal Service Rider
11 ("USR"), which then increase the USR rate and customers' bills.

12 Additionally, PPL Electric already cross-markets its EE&C and USECP programs and
13 provides information about LIHEAP to customers participating in its USECP programs, so
14 those ideas would not produce the significant reductions proposed by Mr. Colton. Also, to
15 the extent that Mr. Colton would like the Company to change how it markets its EE&C
16 program offerings to customers or to adjust the measures and incentives offered under the
17 EE&C Plan, such issues must be addressed in the Company's Phase IV EE&C Plan
18 proceeding or its ongoing Phase V EE&C Plan proceeding.

19 Finally, the Commission should reject any notion that increased enrollment in CAP,
20 under the first outcome metric, could be enough for the Company to achieve the second
21 outcome metric. Again, enrollment in CAP, along with any assistance program offered by
22 the Company for that matter, is voluntary. It is unreasonable to assume that PPL Electric

1 could enroll enough customers in CAP, and that every enrolled customer would make all
2 required payments, in a manner that eliminates defaulted payment arrangements, prevents all
3 service disconnections, and fully resolves existing arrears. There also is no analysis presented
4 by Mr. Colton that achievement of the CAP enrollments under his first outcome metric would
5 be sufficient to enable the Company to achieve the second outcome metric. I strongly
6 recommend that the Commission deny his proposal for these reasons.

7
8 **Q. Mr. Cicero also raises an issue with reconnection fees charged to confirmed low-income**
9 **customers and recommends that PPL Electric waive those reconnection fees for all CLI**
10 **customers whose service is terminated and that those waived reconnection fees be**
11 **recovered as a normalized expense in the next base rate case. (CAUSE-PA St. No. 1, p.**
12 **130.) Please respond.**

13 A. I disagree with this recommendation. Although the Company and other utilities were required
14 not to impose reconnection fees on “protected customers” under the Commission’s October
15 13, 2020 Order at the COVID-19 Emergency Order proceeding at Docket No. M-2020-
16 3019244, that requirement has long since lapsed. Therefore, the Company is permitted under
17 the Commission’s regulations to assess reconnection fees to customers, including confirmed
18 low-income customers. See 52 Pa. Code § 56.191. These reconnection fees cover the
19 Company’s costs to restore service after the lawful termination of service.

20 Moreover, similar to Mr. Cicero’s proposal regarding security deposits, the costs
21 associated with waiving these reconnection fees are not reflected in the FPFTY of the
22 Company’s base rate case filing. As such, implementation of this proposal would result in

1 the Company not recovering the expenses associated with this proposal through base rates
2 established in this proceeding. Thus, Mr. Cicero's recommendation should be denied.

3
4 **IV. PAYMENT TRANSACTION FEES**

5 **Q. I&E and OCA agree with the Company's proposal to recover the costs of payment**
6 **transaction fees in base rates but disagree with the Company's claim amount,**
7 **recommending an allowance of \$3,831,100, or a reduction of \$1,149,000. (I&E St. No.**
8 **2, pp. 25-28; OCA St. 1, pp. 12-13.) What issues do their witnesses have with the claim**
9 **amount?**

10 A. I&E Witness Keller disputes the 30% growth rate used to calculate the amount for the FPFTY
11 on the grounds that it is speculative. He also contends that the Company's proposal does not
12 reflect the cost savings associated with customer service, such as call center, mail handling,
13 uncollectibles, collection costs, etc. Similarly, OCA Witness Morgan asserts that a 15%
14 growth rate should be used instead of the 30% growth rate. Based on that position, he
15 recommends a \$792,000 reduction in the Company's claim.

16
17 **Q. Do you agree with these positions?**

18 A. No. To clarify, as explained by the Company in its response to discovery request OCA XXV-
19 18, attached as PPL Electric Exhibit LN-10R, the expense amount included in the FPFTY is
20 \$5.2 million, not approximately \$4.98 million. The \$4.98 million referenced in my direct
21 testimony was based on PPL Electric's original analysis around payment transaction fees, was
22 completed using the period November 2023 through October 2024, and resulted in

1 approximately \$4.98 million. However, further revision to that analysis using data for the
2 twelve months ending June 2025 showed transaction fees totaling approximately \$4 million
3 over that period and, thus, resulted in the \$5.2 million used in the FPFTY based on the 30%
4 growth rate (i.e., \$4 million x 1.30 = \$5.2 million).

5 Despite his reliance on the outdated approximately \$4.98 million figure, Mr. Keller
6 correctly notes that the FPFTY claim is based on a 30% gross-up due to an assumed increase
7 in the amount of fees if the Company's proposal were adopted. That is how the Company
8 arrived at its proposed expense claim of approximately \$5.2 million, as noted previously. PPL
9 Electric's projected growth trend is reasonable, given that the Company is expanding digital
10 payment methods to include Venmo, Apple Pay, and other digital methods. The Company
11 maintains that offering these additional payment methods along with the elimination of the
12 payment transaction fees will further accelerate the growth of the digital payment channel.
13 Due to the above circumstances, PPL Electric believes the Company's claim of \$5.2 million
14 is a conservative estimation for the FPFTY expenses and that no disallowance of the claimed
15 expenses should be permitted.

16
17 **Q. Does OCA Witness Alexander make any related recommendations?**

18 A. Yes. She recommends that as part of the Company's rebuttal testimony, PPL Electric provide
19 documentation that the fees it seeks to include in rates are the lowest cost and reflect a more
20 recent analysis of handling these transactions in house, or by means of a more recent request
21 for proposals. (OCA St. 7, p. 25.)

22

1 **Q. Please respond to this recommendation.**

2 A. I disagree with her proposal. The transaction fees are being charged by large financial
3 institutions which are industry standard with little or no room for negotiation. Paymentus's
4 administration fees are not directly charged to PPL Electric, but rather embedded in the
5 transaction fees. Theoretically PPL Electric could handle this administration internally.
6 However, it would require the Company to enter into an area that it has no expertise or
7 infrastructure. I am positive that if PPL Electric were to handle the service Paymentus
8 provides in-house, it would cost more for equal or lesser quality of the same service.

9
10 **Q. Does CAUSE-PA Witness Cicero support the Company's proposal?**

11 A. Yes, but unlike I&E and OCA, he does not take a position on the amount of the claim.
12 (CAUSE-PA St. No. 1, pp. 110-11.)

13
14 **V. UNIVERSAL SERVICE PROGRAMS**

15 **A. Salaries and Wages**

16 **Q. I&E Witness Keller, OCA Witness Colton, CAUSE-PA Witness Cicero, and EJA**
17 **Witness Rábago recommend that the Commission reject the Company's proposal to**
18 **recover the salaries and wages for its USECP employees through the USR. Could you**
19 **please summarize their positions on the Company's proposal?**

20 A. I&E Witness Keller argues that shifting USECP salary and wage costs from base rates to the
21 USR would guarantee full cost recovery and remove Commission oversight of their

1 reasonableness. He also claims the shift would allow the Company to change staffing levels
2 without scrutiny. (I&E St. No. 2, p. 15.)

3 OCA Witness Colton contends that internal administrative expenses are not
4 appropriate for recovery through a universal service rider because they do not materially
5 fluctuate. He further asserts that the proposal would give the Company broad discretion to
6 classify salaries as universal-service-related, eliminate offsets that currently balance cost
7 reductions, and ultimately burden ratepayers with increased internal costs without providing
8 corresponding benefits. (OCA St. 8, pp. 61-64.)

9 CAUSE-PA Witness Cicero disagrees with the proposal because: (1) fully reconciling
10 these costs does not benefit ratepayers; and (2) right now, 87% of these costs are assigned to
11 residential customers, while 100% would be assigned to residential under the current construct
12 of the USR. (CAUSE-PA St. No. 1, pp. 96-97.)

13 EJA Witness Rábago contends that recovering USECP salaries through the USR will
14 “dilute[]” the “USR funds available.” (EJA St. No. 1, p. 17.)

15
16 **Q. Do you agree with their positions and recommendations?**

17 A. No. As a threshold matter, moving these costs to the USR does not eliminate the ability to
18 challenge the reasonableness and prudence of these costs. The USR is a fully reconcilable
19 surcharge mechanism that is subject to audit by the Commission. Further, the Company must
20 submit reconciliation statements for the USR showing the actual expenditures incurred by
21 PPL Electric. Therefore, while the Company’s staffing requirements are within PPL
22 Electric’s discretion, it is not as though PPL Electric can add employees’ costs to the USR

1 with impunity. The reasonableness and prudence of the Company's expenditures will always
2 remain subject to review and challenge.

3 In addition, I disagree with the notion that customers do not benefit under this
4 proposal. To the extent that there are any cost savings attributable to increased USECP
5 staffing, those cost savings can be reflected in the O&M expense claims in future base rate
6 cases. Moreover, a reliance on a potential increase in USECP staffing is flawed. The
7 Company does not project an increase in USECP staffing beyond the levels estimated for the
8 FPFTY. Also, the Company's proposal would flow back any cost savings attributable to
9 decreases in the USECP staffing. Indeed, any over-recoveries under the USR are reflected in
10 the E-Factor and put downward pressure on the USR rate. Without the Company's proposal,
11 PPL Electric would continue to recover the USECP salary and wage expenses at the level
12 established in this proceeding and not have to refund any amount if the actual expenses are
13 lower.

14 I also maintain that these costs are appropriately recovered through the USR from
15 residential customers. As it stands, residential customers are the only customer class eligible
16 to participate in the USECP programs. Consistent with Commission practice for similar types
17 of costs, like the EE&C program costs, the expenses should be recovered from the customer
18 class whose members are eligible to participate in the programs and directly cause these costs
19 to be incurred due to such participation. However, as noted in PPL Electric Witness Joseph
20 Lookup's testimony (PPL Electric St. No. 16-R), the Company is proposing to allocate a
21 portion of USR costs to the newly created LP-6 rate class. This will mitigate the concern

1 raised by Mr. Cicero that the Company's proposal will shift 100% of the costs to residential
2 customers while today they are only responsible for 87%.

3 Finally, Mr. Rábago appears to not understand how the USECP budgets and USR
4 operate. When given the opportunity to clarify his statement in discovery, Mr. Rabago
5 asserted that "[i] the fund pays for new costs and the fund budget is not increased, the funds
6 available for other program spending would be reduced." (PPL Electric Exhibit LN-11R [EJA
7 Answer to PPL to EJA-II-6].) No part of PPL Electric's proposal would affect the budgets
8 for the USECP programs. Because there is no cap on the USR, these costs, along with all the
9 other recoverable costs under the USR, would simply flow through the rider. Thus, PPL
10 Electric's USECP programs and their budgets would be unaffected by the Company's
11 proposal.

12
13 **Q. I&E Witness Keller states that if USECP salary and wage costs are moved from base**
14 **rates to the USR, the Commission must make corresponding downward adjustments to**
15 **payroll, benefits, and any other affected expenses; otherwise, the Company would**
16 **recover the same costs twice—once in base rates and again through the USR. (I&E St.**
17 **No. 2, pp. 16-17.) Do you agree?**

18 **A.** No. The Company already backed out the approximately \$1.4 million from its FPFTY claim
19 to ensure that PPL Electric would not double-recover these expenses if its proposal were
20 approved. As such, if the Commission denies the Company's proposal, then an additional
21 \$1.4 million needs to be added to the salary and wage expense reflected in the Company's
22 revenue requirement.

B. CAP Cost Recovery Offset

Q. OCA Witness Colton opposes the Company's proposal to eliminate the CAP recovery offset from the USR and recommends that the Commission deny the proposal. (OCA St. 8, p. 6.) What reasons does he provide for his position?

A. Mr. Colton argues that eliminating the existing \$100 CAP recovery offset would result in double recovery because, in his view, portions of CAP credits and arrearage forgiveness are already reflected in base rates. He notes that other Pennsylvania utilities maintain similar offsets and attempts to distinguish the Commission's PGW decision. Mr. Colton further cites data on pre-CAP arrearages and their age to claim it is incorrect to assume none of those arrears affected PPL Electric's bad-debt expenses prior to CAP enrollment. He also references disconnection data showing that nearly one-third of confirmed low-income customers remain disconnected to support his position. (OCA St. 8, pp. 65-78.)

Q. What is your response?

A. I disagree with Mr. Colton that the Company will realize double recovery of USR arrearage forgiveness and bad debt expense if the CAP Offset is eliminated. Mr. Colton's proposal attempts to take one O&M expense and treat it differently from how all other costs are claimed in the FPFTY. He also makes the mistake of assuming that customer behavior will only occur in a way that results in PPL Electric double recovering certain expenses. This ignores the fact that customer behavior is dynamic. I agree that there are some customers who are not currently enrolled in CAP with arrearages that make up a portion of the Company's bad debt

1 expense claim in its FPFTY. What is equally true, however, is that there are current CAP
2 customers with arrearages projected to be recovered through the USR that will default on their
3 CAP payments and have their arrearages be moved to a bad debt expense account. The
4 Company, consistent with ratemaking principles, normalizes its actual costs (including
5 working capital, credit, and collection costs referenced by Mr. Colton) when it is making its
6 claim for costs in the FPFTY. This process accounts for the movement of customers coming
7 on and off of CAP and does not require the additional “adjustment” proposed by Mr. Colton.
8

9 **Q. How do you respond to Mr. Colton’s statement that the Company has not carried its**
10 **burden to eliminate the CAP Offset?**

11 A. I disagree. As I explained, there is no reason to believe that the Company’s revenue
12 requirement in its FPFTY includes double recovery of USR arrearage expenses and bad debt
13 expenses. PPL Electric has provided actual numbers of what it anticipates its expenses will
14 be in the FPFTY and based its claim on those figures. Mr. Colton repeatedly states in his
15 testimony that there is the “potential” or that he “assumes” that there will be double recovery
16 of certain expenses, but he cannot identify the actual amount of double recovery. Given that
17 Mr. Colton is unable to establish the actual amount of double recovery, he recommends that
18 the Company continue to use an arbitrary offset amount to account for his “assumed” double
19 recovery. From my perspective, the Company has met its burden in presenting its revenue
20 requirement for the FPFTY, and Mr. Colton has failed to rebut the Company’s position that
21 there is no double recovery of any costs in the FPFTY.
22

1 **Q. Do you have a position on Mr. Colton’s statement that many of the other Pennsylvania**
2 **utilities have a CAP Offset?**

3 A. Yes, in that I think it is largely irrelevant. The fact that other utilities have a CAP Offset does
4 not prove that PPL Electric is double recovering certain costs to justify the continuance of its
5 CAP Offset. Additionally, many of the CAP Offsets were implemented as part of a settlement
6 agreement with no admission of actual double recovery. This was the case when PPL Electric
7 originally agreed to establish its CAP Offset.

8
9 **Q. If the Commission were to accept Mr. Colton’s proposal, should there nevertheless be**
10 **adjustments to the Company’s existing CAP Offset?**

11 A. Yes, while I strongly disagree that any CAP Offset is necessary, if it is to continue the
12 threshold upon which the Company begins charging the \$100 offset needs to be adjusted.
13 Currently, PPL Electric’s CAP Offset is \$100/month for every CAP customer over 44,000
14 enrolled. The logic, albeit flawed, behind the need for the CAP Offset is that it will prevent
15 double recovery of certain expenses. The alleged double recovery can only occur if there is
16 significant change in CAP participation from what the Company projected in its FPFTY. At
17 the time of the settlement agreement that established the current CAP Offset in the 2015 Rate
18 Case, the Company’s average level of customers participating in CAP was approximately
19 44,000. Enrollment in PPL Electric’s CAP has dramatically increased and is routinely more
20 than 70,000 customers, as I noted earlier in my rebuttal testimony. If the Commission decides
21 that the CAP Offset should remain, the Company should only pay the \$100 offset amount on

1 customers participating above the 75,000 enrollment level, which is the Company's projected
2 CAP participation level for the FPFTY going forward.

3
4 **C. Universal Service Programs**

5 **Q. CAUSE-PA Witness Cicero notes that PPL Electric has made no proposals in this base**
6 **rate case to substantively change its USECP programs and then proceeds to make a**
7 **series of recommended changes to the Company's USECP programs. (CAUSE-PA St.**
8 **No. 1, pp. 49-85.) Before addressing those recommendations in detail, do you believe it**
9 **is appropriate to make substantive changes to the Company's Commission-approved**
10 **USECP programs in this proceeding?**

11 A. No. I believe that such changes should be proposed and evaluated in a USECP proceeding,
12 not a base rate proceeding. I am advised by counsel that the Commission has previously
13 rejected recommendations to revise low-income and universal service programs on the
14 grounds that such proposals should be addressed in USECP proceedings. *See Pa. PUC v.*
15 *PECO Energy Co.*, Docket Nos. R-2020-3018929, *et al.*, pp. 195-96 (Order entered June 22,
16 *2021); Pa. PUC v. Columbia Gas of Pa. Inc.*, Docket Nos. R-2020-3018835, *et al.*, pp. 160-
17 *61 (Order Entered February 19, 2021). Moreover, in PPL Electric's 2012 base rate case, CEO*
18 *proposed to increase the annual funding for the company's LIURP. See Pa. PUC v. PPL Elec.*
19 *Utils. Corp.*, Docket Nos. R-2012-2290597, pp. 48-51 (Order entered Dec. 28, 2012). The
20 Commission rejected that proposal, finding that "all aspects of USPs" should be addressed
21 "through the triennial filing process and to collect all revenues through a rider to base rates."
22 (*Id.*, p. 51.) Therefore, consistent with these prior findings, the Commission should deny any

1 attempts to modify the Company's USECP through this base rate case. These issues are best
2 addressed in the context of the Company's USECP proceeding, where any interested parties
3 and stakeholders can be heard on substantive changes to the Commission-approved USECP
4 programs, including their design, operation, and funding.

5
6 **Q. Nevertheless, do you have responses to these issues and recommendations concerning**
7 **the Company's Commission-approved USECP programs?**

8 A. Yes.

9
10 **Q. CAUSE-PA Witness Cicero recommends that PPL Electric modify its monthly CAP bill**
11 **review process to review rates for all CAP customers. (CAUSE-PA St. No. 1, p. 52.) Do**
12 **you agree?**

13 A. No. Under the Company's current process, a customer is only placed on Average Bill if their
14 PIP amount is higher than the calculated Average Bill. Once enrolled, the monthly review
15 process does include customers on Average Bill. If the customer's current Average Bill
16 becomes higher than the Average Bill that was used when they entered the program, the
17 Company will review and adjust the amount as needed. PPL Electric does not compare the
18 updated amount against the PIP, because the PIP was originally the higher amount—meaning
19 any adjustment would result in a lower Average Bill, not an increase above the PIP.

20
21 **Q. Mr. Cicero recommends eliminating the Company's maximum CAP credit policy or,**
22 **alternatively, increasing the credit limits by at least 60%. He tries to support this**

1 **proposal by asserting that current limits are insufficient and citing data showing that**
2 **some CAP customers have already exceeded their annual credit caps. (CAUSE-PA St.**
3 **No. 1, pp. 54-55, 60-62.) Please respond.**

4 A. I disagree with this recommendation. The Company's current maximum CAP credit covered
5 approximately 90% of all OnTrack participants and has resulted in an 89% success rate.
6 Additionally, there is a process in place to allow for exceptions to maximum cap credit for
7 eligible customers. The intent of OnTrack is not to have unlimited subsidies but instead to
8 support the Company's low-income customers with a PIP payment while also managing costs
9 to other residential customers who pay for the program.

10
11 **Q. Please summarize Mr. Cicero's recommendations for the Company's CAP credit**
12 **exemption process and the Company's CAP enrollment efforts. (CAUSE-PA St. No. 1,**
13 **pp. 63-74.)**

14 A. Mr. Cicero recommends that PPL Electric proactively identify customers likely to exceed
15 their CAP credit limits, inform them and Community-Based Organizations ("CBOs") about
16 available exemptions, flag accounts meeting exemption criteria, and automatically apply
17 exemptions when limits are exceeded. He further proposes that the Company present a
18 screening and education plan to the USAC and incorporate feedback and that PPL Electric
19 revise its policy to apply exemptions without requiring customers to submit a new CAP
20 application or re-enroll. (CAUSE-PA St. No. 1, p. 63.)

21 Mr. Cicero alleges that PPL Electric lacks a simplified CAP application for LIHEAP
22 recipients, does not adequately screen customers for CAP eligibility, and lacks a policy to

1 place holds on accounts so customers can enroll in CAP before termination. He also claims
2 that PPL Electric makes reconnection more difficult for terminated customers or applicants
3 with arrears. Specifically, Mr. Cicero recommends that PPL Electric:

- 4 • Use DHS Data Sharing Program information to auto-enroll eligible households and file
5 a USECP amendment within 120 days;
- 6 • Revise its auto-enrollment letter to clearly outline rights, responsibilities, and opt-out
7 options;
- 8 • Conduct routine income and CAP-eligibility screening for applicants and callers;
- 9 • Offer income-screening for all new and moving customers and expand screening
10 through phone and web;
- 11 • Implement these screening and referral processes within 120 days;
- 12 • Apply a 15-day hold when a customer applies for CAP; and
- 13 • Allow terminated customers or applicants with arrears to reconnect through CAP
14 enrollment without added barriers.

15
16 **Q. Do you agree with these recommendations?**

17 A. No, I disagree with Mr. Cicero's recommendations. First, the Company participates in the
18 DHS Data Sharing Program and uses LIHEAP information to expedite and streamline CAP
19 enrollment for income-qualified customers. The Company follows the data-privacy
20 conditions and consent requirements, asking the customer to confirm their participation.

21 Second, the Company does screen customers for CAP eligibility. Below is a summary
22 of PPL Electric's **Key Outreach Strategies and Successes:**

- 1 • **Multi-Channel Communication:** The Company uses targeted outreach through paid
2 advertising, print and digital newsletters, email, text messaging, phone calls, social
3 media, and website content. These efforts ensure customers receive timely and relevant
4 information about available assistance.
- 5 • **Targeted Campaigns:** PPL Electric leverages enrollment data to identify customers
6 who may qualify for additional programs and encourages them to apply, helping
7 maximize benefits. For example, customers receiving LIHEAP assistance are
8 proactively contacted about OnTrack eligibility.
- 9 • **In-Person Engagement:** Recognizing that not all customers are digitally connected,
10 PPL Electric supported in-person events across its service territory in 2025 to provide
11 direct education and enrollment assistance.
- 12 • **Language Accessibility:** Outreach materials and applications are available in Spanish,
13 and PPL Electric maintains a language line for translation services.
- 14 • **Seasonal and Recurring Communications:** PPL Electric runs quarterly campaigns
15 like “Seasonal Savings Solutions” to educate customers on energy management and
16 promote assistance programs during peak heating and cooling periods.
- 17 • **Enhanced Digital Tools:** Promotional messaging has been added to self-service flows
18 for new customers and recertification reminders for OnTrack participants, improving
19 early enrollment and retention.
- 20 • **Community and Stakeholder Engagement:** PPL Electric hosts educational webinars
21 for community partners and legislative staff, distributes stakeholder newsletters, and
22 participates in events such as Be Utility Wise to broaden awareness.

1 While the Company continues to refine and enhance screening tools, a blanket screening at
2 every contact regardless of income is not practical or consistent with current customer service
3 standards.

4 Third, regarding the proposed 15-day hold when a CAP application is submitted, I
5 previously explained why Mr. Cicero's recommendation should be rejected, as the Company
6 already has a hold procedure to allow for customers to apply for OnTrack.

7 Fourth, with respect to Mr. Cicero's proposed reconnection change, customers are
8 provided with opportunities throughout the collection process to apply for eligible program
9 assistance. However, once disconnected, customers who are not enrolled in such programs
10 are reasonably expected to make the required payments to reconnect service.

11
12 **Q. What else does Mr. Cicero recommend related to Operation HELP?**

13 A. He recommends that sub-metered tenants who are income eligible should be eligible to
14 receive an Operation HELP or Good Neighbor Fund grant from PPL and that such eligibility
15 be stated in PPL Electric's tariff. (CAUSE-PA St. No. 1, pp. 122-23.)

16
17 **Q. Do you agree with that proposal?**

18 A. No. With respect to Operation HELP, it is a program designed for PPL Electric customers,
19 which sub-metered tenants are not. The Company does not have a relationship with these
20 individuals and is not privy to their lease arrangement with respect to energy costs. Operation
21 HELP grants are credited directly to customer bills, and since these individuals are not
22 customers there is no bill on which to apply a credit. Meanwhile, the Good Neighbor Fund is

1 supported by PPL Electric, but it is not administered by the Company. PPL Electric is unable
2 to alter the participation terms of the Good Neighbor Fund because it is not its program.

3
4 **Q. CAUSE-PA Witness Cicero argues that CAP will not shield low-income households**
5 **from the proposed rate increase because it is undersubscribed, customers on the**
6 **average-bill option will bear the full impact, and annual CAP credit limits restrict the**
7 **assistance households can receive. (CAUSE-PA St. No. 1, pp. 44-46.) Please respond.**

8 A. As I noted previously, PPL Electric has seen increased enrollments in CAP year over year
9 from 2022 to 2024. PPL Electric will continue its efforts to encourage customers to enroll in
10 CAP so that they can mitigate the impact of the base rate increase on their bills and help pay
11 down existing balances in arrears. Moreover, PPL Electric reviews customers' accounts to
12 see if the PIP option is the most advantageous one available, pursuant to the terms of its
13 Commission-approved USECP. Therefore, if customers would be worse off on the Average
14 Bill option than the PIP option, PPL Electric will make that switch. Furthermore, as I
15 addressed previously, I disagree that an increase in the maximum CAP credits is necessary.

16
17 **Q. Mr. Cicero argues that LIURP is underperforming and objects to the current 5-year**
18 **lookback for customers who received WRAP services. He recommends increasing the**
19 **LIURP budget by \$2.4 million and limiting the 5-year lookback to customers who**
20 **actually received WRAP weatherization. (CAUSE-PA St. No. 1, pp. 74-79.) Please**
21 **respond.**

1 A. I disagree with the recommendation to eliminate the 5-year lookback. Again, this issue is
2 better suited to be addressed in the Company's USECP proceeding, where the design and
3 operation of WRAP is properly evaluated. Moreover, the 5-year lookback protects against
4 repeated or duplicative weatherization that does not produce additional savings. WRAP is a
5 deep, comprehensive treatment program, so performing multiple full WRAP jobs on the same
6 household within 5 years is rarely cost-effective.

7 Furthermore, the Company's LIURP budget increased from \$10 million to \$12
8 million in its most recent USECP proceeding. This was a substantial increase based on annual
9 enrollment of 3,500 customers and occurred in the appropriate proceeding. Budget expansion
10 solely for the sake of expansion without a corresponding showing of cost-effectiveness and
11 contractor availability would impose unnecessary additional costs on residential ratepayers.

12
13 **Q. Do you agree with Mr. Cicero that a higher fixed residential customer charge**
14 **undermines the purpose of the Company's LIURP (CAUSE-PA St. No. 1, pp. 29-31)?**

15 A. I disagree with his characterization. PPL Electric is seeking less than a \$3 increase in its fixed
16 residential customer charge. Although increases in fixed charges reduce the total amount of
17 the bill that could be reduced through efficiency measures, the vast majority of the customer's
18 bill is still driven by consumption-based charges. Therefore, customers still have an incentive
19 to implement efficiency measures, including those offered under LIURP. This is especially
20 true for the Company's low-income customers who tend to be higher users of electricity
21 compared to residential customers generally, as noted in the data produced in response to

1 CAUSE-PA to PPL Set I, No. 2. (See PPL Electric Exhibit LN-12R [Answer to CAUSE-PA
2 I-20 and CAUSE-PA I-20 Attachment 1.)

3
4 **Q. What allegations and recommendations are made by Mr. Cicero concerning the**
5 **Company's Operation HELP?**

6 A. Mr. Cicero argues that PPL Electric lacks adequate oversight of its CBOs administering
7 Operation HELP and that the hardship fund is underutilized. He recommends revising CBO
8 policies to provide clearer direction, requiring coordination with the Company before denying
9 grants, and standardizing guidance on grant amounts. He further proposes that PPL Electric
10 track key data on hardship-fund applications and denials—including counts of applicants,
11 confirmed low-income and CAP applicants, and denial reasons—and implement these
12 reforms within 120 days. (CAUSE-PA St. No. 1, pp. 79-82.)

13
14 **Q. What is your response?**

15 A. I disagree with Mr. Cicero's claims about an alleged lack of oversight of CBOs. The Company
16 maintains established procedures, training, and written guidance for CBO partners, and the
17 Company monitors program performance, budget status, and compliance with eligibility
18 criteria. The determination of the grant based on established eligibility criteria belongs with
19 the CBOs.

20 Additionally, Operation HELP's utilization levels vary from year to year based on
21 customer need, seasonal demand, the availability of external assistance programs such as
22 LIHEAP, and the timing of grant cycles. Lower grants in one period does not indicate

1 underperformance or inadequate oversight. In fact, these results are common during
2 moratorium months because customers need to apply for the assistance.

3 Finally, the approach to use one application for OnTrack and Operation HELP allows
4 the CBO to match the customer to the program that best fits the customer's need. If a customer
5 can benefit from long-term solution like OnTrack, PPL Electric would not want to give them
6 a short solution of a one-time Operation HELP grant.

7
8 **Q. CEO Witness Warabak raises a concern that the Company did not propose any**
9 **changes to its USECP programs as part of this base rate case. (CEO St. No. 1, p. 4.)**
10 **Please respond.**

11 **A.** As I explained previously, it is not appropriate to make changes to a Commission-approved
12 USECP in a base rate proceeding. Any changes to that USECP would require a rescission
13 or amendment of the Commission's Order approving the currently-effective USECP.
14 Because that matter is outside the scope of this case, and the USECP docket is not
15 consolidated with this base rate case, no changes to the USECP should be made in this
16 proceeding.

17
18 **Q. Ms. Warabak also states that the Commission should not allow an increase in rates and**
19 **allow an increase in the fixed monthly consumer charge without requiring an increase**
20 **in universal service funding that would allow some relief to low-income customers,**
21 **asserting that the result of this proceeding will impact whether the Company's USPs**
22 **are appropriately funded and available, as required by the Electric Choice Act. (CEO**

1 **St. No. 1, p. 5.) Do you agree?**

2 A. No. Again, the funding of the USECP programs should be addressed in the context of a
3 USECP proceeding.

4
5 **Q. Ms. Warabak recommends increasing the LIURP budget by \$900,000, requiring PPL**
6 **to continue using CBOs to administer universal service programs, and increasing the**
7 **shareholder contribution to the hardship fund by \$500,000 annually. (CEO St. No. 1,**
8 **pp. 7-10.) Do you agree with these recommendations?**

9 A. No. The design and funding of the USECP programs should be addressed in the context of
10 a USECP proceeding. Moreover, the Company has proposed no changes to its use of CBOs
11 in this case, so Ms. Warabak's recommendation on that point is unnecessary. Furthermore,
12 PPL Electric's annual LIURP budget should be driven by the amount of work that can be
13 reasonably performed based on contractor availability, the amount of eligible customers
14 willing to participate, and the likely measures required by those customers. Ms. Warabak
15 appears to pick this number on the grounds that it "would allow the Company to complete
16 approximately 300 more jobs annually" without any supporting analysis that 300 more jobs
17 annually could be completed with those factors in mind. Therefore, her recommendation
18 should be rejected.

19
20 **D. Impact of Large Load Interconnections on CAP Costs**

21 **Q. Other parties' witnesses contend that the large load interconnections will have**
22 **downstream impacts on residential rates by increasing the Company's universal service**

costs. (OCA St. 8, pp. 93-94; OSBA St. No. 1, p. 18; CAUSE-PA St. No. 1, pp. 22-24; EJA St. No. 1, pp. 17-18.) What is your position on those alleged cost increases?

A. As I stated previously, I believe that universal service costs should be recovered from residential customers because they are the customers who are eligible for the USECP programs and directly cause the Company to incur the costs associated with those programs. However, see Mr. Lookup's rebuttal testimony (PPL Electric St. No. 16-R) for the Company's proposal on allocating a portion of USR costs to a newly created large load rate schedule.

VI. SUPPLIER TARIFF CHANGES AND PAYMENT FOR ELECTRONIC DATA INTERCHANGE (EDI) TRANSACTIONS

Q. Do any parties oppose the Company's proposed changes to its Supplier Tariff?

A. Only one: RESA.

Q. What issues does RESA raise with the Company's Supplier Tariff?

A. RESA Witness Lacey argues that the Company's changes to the Supplier Tariff are not appropriately raised in a base rate proceeding and that the Commission should reject the Company's Supplier Tariff as a result. (RESA St. No. 1, p. 6.) However, if the Commission does consider the proposal, then he asks that the Commission reject: (1) the proposal to assess EGSs the Electronic Data Interchange ("EDI") and Data Universal Numbering System ("DUNS") testing costs that are currently passed onto ratepayers through base rates; (2) the proposed credit requirements for suppliers; (3) the proposed rule defining "Standard Rates" and limiting the amount per quarter an EGS is permitted to submit; and (4) any new proposal

1 to require EGSs to provide written authorization a pre-condition to receiving the information
2 necessary to serve their customers. (RESA St. No. 1, pp. 3-5.)
3

4 **Q. Do you agree with Mr. Lacey that the Company's proposed Supplier Tariff is not**
5 **appropriately raised in this base rate proceeding?**

6 A. No. I am advised by counsel that nothing prohibits the Company from proposing its updated
7 Supplier Tariff within the context of a base rate proceeding. In fact, the Commission has
8 addressed changes to supplier tariffs in other base rate proceedings. *See, e.g., Pa. PUC v.*
9 *Peoples Natural Gas Co. LLC*, 2011 Pa. PUC LEXIS 1930 (Recommended Decision dated
10 Apr. 27, 2011), *adopted*, Docket Nos. R-2010-2201702, *et al.* (Order entered June 9, 2011);
11 *Pa. PUC v. Peoples Natural Gas Co. LLC*, 2017 Pa. PUC LEXIS 287 (Order entered Oct. 3,
12 2019).

13 Moreover, a base rate proceeding is a significant matter that draws great interest across
14 many interested stakeholders, from individual customers to large trade associations, like
15 RESA. PPL Electric determined that a base rate proceeding would provide a better
16 opportunity for interested stakeholders to evaluate the Company's updated Supplier Tariff, as
17 opposed to a separate proceeding limited to the Supplier Tariff that would likely draw much
18 less interest.

19 I also note that Mr. Lacey's allegations that a base rate proceeding does not provide a
20 sufficient opportunity to review the Company's proposed changes are unfounded. The
21 Company's updates to the Supplier Tariff are mostly clarifying edits, with only a handful of
22 truly substantive changes to which Mr. Lacey directly responds. This contrasts with the many

1 substantive changes that PPL Electric has proposed to its Retail Tariff in this same proceeding.
2 To my knowledge, no party has argued that the Company's proposed changes to its Retail
3 Tariff should be evaluated in a different proceeding. Also, although Mr. Lacey contends that
4 that "some" of the "clarifying" edits to the Supplier Tariff "will have a significant impact on
5 how suppliers currently interact with PPL to facilitate the ability of consumers to choose an
6 alternative supplier," he fails to articulate how many, if not all, of those clarifying edits would
7 do so. As for the truly substantive changes to the Supplier Tariff, Mr. Lacey responds to them
8 in his direct testimony.

9 Further, as part of updating its Supplier Tariff, PPL Electric benchmarked its existing
10 Supplier Tariff against its Pennsylvania peer electric distribution companies ("EDCs"),
11 particularly FirstEnergy Pennsylvania Electric Company ("FE PA") given that FE PA's and
12 PPL Electric's service territories share significant boundaries. Many of the proposed changes
13 are consistent with FE PA's Supplier Tariff, so they should not be new to EGSs operating in
14 Pennsylvania.

15 RESA and other parties also had months to review the Company's proposed Supplier
16 Tariff and engage in discovery. RESA availed itself of that option and propounded three sets
17 of discovery totaling 63 discovery requests (not including subparts) and submitted lengthy
18 testimony about the Company's Supplier Tariff and even proposed related Information
19 Technology ("IT") changes that are addressed by PPL Electric Witness Daniel Johnson in his
20 rebuttal testimony (PPL Electric St. No. 19-R).

21 Additionally, it has been decades since the Company revised its Supplier Tariff. A
22 base rate case provides certainty that the Company's much needed updates to its Supplier

1 Tariff are decided within a defined timeframe, as opposed to a separate proceeding that, as
2 counsel advises me, would have no required date for the Commission to issue a Final Order.
3 Much work has already been done to evaluate the Company's proposed changes to its Supplier
4 Tariff, too, so it would be a waste of time and administrative resources simply to start over in
5 another proceeding.

6 Finally, PPL Electric needed to propose its change to the cost recovery for EDI and
7 DUNS testing fees as part of a base rate case, given that those costs are currently recovered in
8 base rates. Had PPL Electric made that proposal in a separate proceeding, RESA and likely
9 other parties would have argued that PPL Electric's proposal should be denied because the
10 Company's base rates are recovering those costs. The only way to accomplish this proposal
11 in a fair and equitable manner was for PPL Electric to make this proposal in a base rate case,
12 so that its FPFTY claim could be adjusted downward to remove those costs from base rates.
13 Likewise, if the Company's proposal is denied, then those costs would need to be put back
14 into base rates through a *pro forma* adjustment, resulting in an increase in the Company's
15 revenue requirement.

16 Mr. Lacey fails to grasp this ratemaking principle, for in discovery, he maintained that
17 "[r]ejecting this change does not require an adjustment to base rates." (PPL Electric Exhibit
18 LN-13R [RESA Answer to PPL to RESA-II-3].) If no adjustment is made to put these costs
19 back into base rates, however, then it would simply result in PPL Electric incurring the costs
20 but not recovering them at all. This further demonstrates why Mr. Lacey's opposition to
21 addressing the Supplier Tariff in a base rate case lacks merit.

1 **Q. Mr. Lacey alleges that portions of the Company’s Supplier Tariff are “vague and could**
2 **be interpreted by PPL to the detriment of competitive suppliers” and provides certain**
3 **examples. (RESA St. No. 1, p. 9.) Please respond.**

4 A. Mr. Lacey only cites two purported examples. The first is with respect to the updated
5 definition of “Meter Read Date,” and Mr. Lacey takes issue with the addition of the phrase
6 “as may be modified from time to time.” PPL Electric made this clarifying edit because the
7 Company’s meter read date already changes from time to time. As noted in Rule 9 of PPL
8 Electric’s Retail Tariff, “Normal billing is for a period of 26-35 days and is based on meter
9 readings taken by the Company at the end of each period.” (PPL Electric Exhibit GEO-1, p.
10 218.) Therefore, the meter read date may not be the same date every month. I also note that
11 PPL Electric has not proposed to change that provision as part of its updated Retail Tariff in
12 this proceeding. (*Id.*) Also, PPL Electric benchmarked its definition of “Meter Read Date”
13 against its peers and found that FE PA’s Supplier Tariff contains that clarifying phrase in its
14 definition of “Meter Read Date.”

15 The second example Mr. Lacey provides concerns the Company’s proposed credit
16 requirements, alleging that various aspects of the proposed revisions to Rule 4.14 are “vague”
17 and unsupported. However, again, PPL Electric benchmarked its Supplier Tariff against its
18 peers, and the same language referenced by Mr. Lacey (e.g., “level of risk,” “load data or
19 reasonable estimates thereof, where applicable,” “recognition of an EGS’s performance”) is
20 included in the Commission-approved Supplier Tariff for FE PA. Further, those terms are
21 self-explanatory, but to further clarify: (1) “level of risk” specifically states that it refers to the
22 “level of risk to the Company,” meaning what the level of risk is that the EGS fails to make

1 its required payments to PPL Electric, based on the factors outlined in Rule 4.14; (2) “load
2 data or reasonable estimates thereof, where applicable” means the EGS’s aggregated load data
3 or a reasonable estimate of such aggregated load; and (3) “recognition of an EGS’s
4 performance” means the EGS’s performance of its obligations under the Supplier Tariff, given
5 that such performance could reduce the Company’s financial risks placed on the Company by
6 that EGS. Even though these terms are clear on their face, Mr. Lacey could have simply asked
7 discovery if the meanings of these terms, which already exist in FE PA’s Commission-
8 approved Supplier Tariff, were unclear. He did not.

9
10 **Q. Mr. Lacey alleges that if PPL Electric is forced to make a separate filing for its Supplier**
11 **Tariff, [i]t is possible that many of the disagreements” with the Company’s Supplier**
12 **Tariff “could be worked out before” a separate filing is made by consulting with the**
13 **“Competitive Supplier community.” (RESA St. No. 1, p. 10.) Do you agree?**

14 **A.** I do not view that as a likely outcome. Collaboratives with suppliers and other interested
15 stakeholders often languish for months or years without clear movement or direction. I
16 believe that such consultation would only serve to further delay the Company making much
17 needed updates to its Supplier Tariff, which has been largely unchanged since the advent of
18 retail choice in Pennsylvania in the late 1990’s.

19
20 **Q. Mr. Lacey recommends that the Commission reject PPL Electric’s proposal to assess**
21 **EGSs the EDI and DUNS testing costs that they cause the Company to incur and**
22 **currently pass onto ratepayers. What reasons does he provide for his position?**

1 A. Mr. Lacey's primary argument is that EGSs should not bear these costs because even though
2 they require the EDI transactions and DUNS testing to occur, EGSs require them to operate
3 in the retail market, and all customers (both shopping and non-shopping) purportedly benefit
4 from the implementation of EDI and purportedly benefit from shopping. (RESA St. No. 1,
5 pp. 19-36.) According to Mr. Lacey, the Company is "essentially attempting to 'tax' the EGS
6 community for implementation costs of a market program required by statute." (RESA St.
7 No. 1, p. 20.) He also asserts that the Company's proposal would "erect competitive barriers
8 in the market with respect to customer choice," would contravene how these costs have been
9 treated since the start of retail competition, would be different from the other electric utilities
10 operating in Pennsylvania who do not assess these costs to EGSs, and would be unfair because
11 an EGS must incur costs to "develop EDI systems to communicate with EDCs" along with
12 "data management expenses." (RESA St. No. 1, pp. 21-36.) He also points to various legal
13 authorities that allegedly support his position.

14
15 **Q. Do you agree with Mr. Lacey?**

16 A. No. As an initial matter, PPL Electric will address Mr. Lacey's legal arguments in its Briefs.
17 However, I am advised by counsel that nothing in the Public Utility Code or Commission's
18 regulations prohibits the assessment of these costs directly to the EGSs who cause their
19 incurrence, and the legal authorities upon which Mr. Lacey relies are distinguishable.
20 Moreover, well-established principles of cost causation support the direct assignment of costs
21 to the entities who cause the incurrence of such costs, which, in this case, are the EGSs. For
22 example, PPL Electric is forced to incur a one-time full DUNS testing fee of \$4,867.20 to set

1 up a new EGS and a one-time abbreviated DUNS testing fee of \$2,215.98 when an existing
2 EGS request to set up a new DUNS number. In both cases, PPL Electric only incurs those
3 costs when the EGS requests the testing. Similarly, the EDI transaction fees that PPL Electric
4 proposes to assess EGSs include the cancel/rebill transactions initiated by the EGS. PPL
5 Electric would not bill the EGSs for any cancel/rebill transactions that are initiated by the
6 Company. As a result, PPL Electric's proposal would directly assign, on an individual EGS
7 basis, the specific costs of the EDI transactions and DUNS testing that they caused the
8 Company to incur.

9 In addition, I disagree with the notion that all customers (shopping and non-shopping)
10 benefit from the retail market. Non-shopping customers have made a decision not to shop for
11 competitive electric generation supply service. In other words, they do not use the service for
12 which PPL Electric incurs these EDI transaction and DUNS testing fees. Therefore, given
13 the ability for PPL Electric to directly assign these costs to the cost-causer (i.e., the individual
14 EGS) in an easy fashion, it is inequitable for those customers to pay for these EDI transaction
15 and DUNS testing fees in their rates. As for shopping customers, they arguably could be
16 viewed as benefiting from the retail market, given that they made a decision to switch to a rate
17 for competitive generation supply service. That decision may have been based on various
18 factors (e.g., fixed rates, lower rates, promotional offerings, or alternative energy supply).
19 Therefore, to the extent that EGSs pass on these costs to their shopping customers, then the
20 Company's proposal would result in the costs flowing through to the customers who benefit
21 from those costs being incurred.

1 Furthermore, the Commission itself has recognized that not all customers benefit from
2 the retail market. In fact, with Commission approval, PPL Electric prohibits customers
3 enrolled in its CAP from shopping because their participation in the retail market was causing
4 customers to pay rates that exceeded the Company's PTC. As a result, CAP shopping
5 customers were exhausting their CAP credits more quickly, increasing their arrears, and
6 driving up the Company's uncollectible expenses that are passed onto other customers. Yet,
7 Mr. Lacey appears to believe that these customers have benefited and continue to benefit from
8 the retail market and should pay for these costs in their base rates.

9 Moreover, Mr. Lacey errs in pointing back to how these costs have been treated in the
10 past. The competitive market is now mature, so subsidization by PPL Electric's customers of
11 these costs to support EGSs standing up service and operating in the Company's service
12 territory is no longer needed to ensure the retail competitive market can be created and
13 operated sufficiently.

14 Also, Mr. Lacey's concerns about competitive barriers lack merit. By directly
15 assessing the costs at the individual EGS level, as opposed to designing a charge that is the
16 same for all EGSs, PPL Electric helps ensure that each EGS is bearing its respective costs.
17 For example, a smaller EGS that engages in far fewer EDI transactions would not be charged
18 as much as a larger EGS competitor with substantially more EDI transactions. Therefore, the
19 Company's proposal would not distort competition, as alleged by Mr. Lacey.

20 Additionally, although EGSs may incur costs to "develop EDI systems to
21 communicate with EDCs" along with "data management expenses," that is not a reason to
22 deny the Company's proposal. PPL Electric incurs costs similar to those costs, too, and they

1 are different from the EDI transaction and DUNS testing fees that the Company proposes to
2 assess to EGSs here. In other words, Mr. Lacey is comparing apples and oranges, and the
3 EGSs' incurrence of these other costs should not determine who should bear the costs
4 associated with the EDI transactions and DUNS testing.

5
6 **Q. Did the Company further explain how PPL Electric's assessment of EDI transaction**
7 **fees to EGSs would encourage EGSs to more efficiently use Company resources?**

8 A. Yes. As set forth in PPL Electric's response to RESA I-23, the Company explained that its
9 proposal would: (1) create cost accountability by having the EGSs that generate excessive or
10 redundant transactions bear the cost and, therefore, incentivizing them to streamline
11 processes; (2) promote system efficiency, as EGSs will reduce duplicate requests and improve
12 data quality to avoid costly rejections; and (3) align costs, by allocating the costs directly to
13 the entities driving the expenditures, instead of allocating costs across all ratepayers. (PPL
14 Electric Exhibit LN-14R [Answer to RESA I-23].) As examples of EGSs inefficiently using
15 the Company's sources, PPL Electric has seen a high volume of rejected transactions for EGSs
16 that fail to follow EDI standards and has unnecessary account maintenance.

17
18 **Q. Mr. Lacey also opposes the Company's proposed credit requirements for EGSs. (RESA**
19 **St. No. 1, pp. 37-40.) What is your response to his arguments?**

20 A. Mr. Lacey appears to misunderstand the purpose of the credit requirements. If an EGS does
21 not participate in the Purchase of Receivables ("POR") Program under the Supplier Tariff, the
22 Company cannot offset its payments to EGSs under the POR Program for any costs owed by

1 the EGS. As such, the EGS must pay the Company's Coordination Service Charges. The
2 Company, therefore, has financial risk that the EGS fails to make those required payments.
3 Additionally, PPL Electric developed its credit requirements based on those approved in FE
4 PA's Supplier Tariff, which specifies the same credit amount of \$250,000 for the Met-Ed,
5 Penelec, and Penn Power Rate Districts along with the same credit ratings for S&P of BBB-
6 or higher, Moody's of Baa3 or higher, Fitch IBCA of BBB- or higher, and Duff & Phelps of
7 BBB- or higher. Notwithstanding, the Company would be willing to amend its Supplier Tariff
8 as part of this compliance filing to specify that the credit requirements apply to the EGSs that
9 are not participating in the POR Program. Further, I understand that the financial risk for PPL
10 Electric may be different than FE PA's due to the differences between PPL Electric's POR
11 Program and FE PA's Clawback Clause. As such, PPL Electric would be willing to reduce
12 the required credit amount to \$50,000, which matches the credit amount for the West Penn
13 Rate District in FE PA's Supplier Tariff]

14
15 **Q. Mr. Lacey also opposes the Company's proposed Supplier Tariff Rule 3.1(f), setting**
16 **forth requirements for "Standard Rates" and limiting an EGS to no more than 200**
17 **discrete Rate Ready rates per calendar quarter. What is your response?**

18 A. PPL Electric is withdrawing Rule 3.1(f), so I believe Mr. Lacey's concerns with respect to
19 that provision have been addressed.

20

1 **Q. Mr. Lacey also opposes any requirement for EGSs to provide “written” authorization**
2 **as a pre-condition to receiving information necessary to serve their customers. Did the**
3 **Company make any such proposal?**

4 A. No. To the contrary, PPL Electric proposed updates to its Supplier Tariff that remove that
5 requirement from its existing Supplier Tariff. (See PPL Electric Exhibit LN-1, pp. 19, 124.)
6 Specifically, the new Rule 5.3.3 in the updated Supplier Tariff states:

7 If an EGS wishes to obtain from the Company confidential Customer-
8 specific information about a Customer with whom it is discussing the
9 possibility of providing Competitive Energy Supply but who has
10 restricted access to the information, the Company will only provide
11 such information after receiving written, electronic or telephonic
12 customer authorization from the requesting supplier or attestation
13 from the supplier that it has such authorization. The EGS will share its
14 records of Customer authorization with the Company upon request
15 and those records shall be subject to audit by the Commission.

16 (PPL Electric Exhibit LN-1, p. 19.) Right now, the relevant provision is Rule 5.3.4 in the
17 existing Supplier Tariff states, in pertinent part, “the Company will only provide such
18 information if the EGS provides to the Company a copy of written documentation indicating
19 that the Customer has authorized the release of Customer information to the EGS or if the
20 Customer has agreed to release the information during the enrollment process.” (PPL Electric
21 Exhibit LN-1, p. 124.)

22 I do note, however, that there is language in the Load Data Supply Charge section that
23 could be interpreted as conflicting with the proposed Rule 5.3.3. PPL Electric will clarify that
24 provision as follows in its compliance tariff filing in this case (new text in bold):

25 No Customer-specific information will be supplied to an EGS **except**
26 **in accordance with Rule 5.3.3 before the Company’s receipt of a**
27 **~~Customer’s written authorization to release such data to such~~**
28 **EGS.**

1
2 **Q. Mr. Lacey also recommends that PPL Electric update its IT systems to support “[a]**
3 **migration of the NEM customer policies to be aligned with the other Pennsylvania**
4 **EDCs.” (RESA St. No. 1, pp. 4, 17-18.) Please respond.**

5 A. PPL Electric is unaware of any complaints from EGSs about its net metering policies, nor is
6 the Company aware of any EGSs not being able to provide service to customer-generators in
7 its service territory because of the Company’s net metering policies. Therefore, I do not see
8 the need to undertake any changes to the Company’s current processes or systems to
9 accommodate Mr. Lacey’s proposed changes.

10
11 **Q. Mr. Lacey further proposes that the Commission establish a “strict standard response**
12 **time for supplier inquiries to no more than one (1) full business day,” on the grounds**
13 **that “PPL response times are notoriously slow.” (RESA St. No. 1, pp. 4, 18.) Do you**
14 **agree with this recommendation?**

15 A. No. PPL Electric strives to respond as soon as practicable to EGSs’ inquiries. However, no
16 strict standard should be imposed on the Company, especially the aggressive one business day
17 requirement proposed by Mr. Lacey. The Company’s response time is affected by several
18 factors, including, but not limited to, employee availability and workload and the number and
19 complexity of inquiries. To meet a one business day response time, PPL Electric would need
20 to hire several new employees that could respond to supplier inquiries. Nothing presented by
21 Mr. Lacey quantifies that the benefits of this proposal would outweigh the significant increase

1 in expenses that would need to be recovered from the Company's ratepayers through base
2 rates.

3
4 **Q. Mr. Lacey criticizes the Company's proposed Supplier Tariff for failing to include a**
5 **definition of "Bill Ready" when PPL Electric included a definition of "Rate Ready."**
6 **(RESA St. No. 1, p. 7.) Please respond.**

7 A. PPL Electric would support including a definition of "Bill Ready." As noted in my direct
8 testimony and PPL Electric Exhibit LN-2, a major objective in updating the Supplier Tariff
9 for the first time in decades was to add definitions that provide clarity to EGSs and customers.
10 In response to Mr. Lacey's concerns, PPL Electric would be willing to add the following
11 definition of "Bill Ready" to its Supplier Tariff as part of its compliance filing in this
12 proceeding:

13 *Bill Ready* – When an EGS that employs the Consolidated EDC
14 Billing option calculates its Customer's charges and provides the EDC
15 the Customer's EGS charges to be billed.

16 I note that this is the same definition currently approved in FE PA's Supplier Tariff. *See*
17 FirstEnergy Pennsylvania Electric Co., Tariff – Electric Pa. P.U.C. No. S-1, Original Page
18 005.

19
20 **Q. Mr. Lacey also raises a concern that the Competitive Billing Specifications Rider**
21 **provides requirements for a "Bill Ready billing scenario" but is "silent on the mechanics**
22 **for Rate Ready billing." (RESA St. No. 1, p. 7.) Please respond.**

1 A. I note that the Company has not proposed any substantive changes to this provision in the
2 Competitive Billing Specifications Rider, as seen in the redline version of the Supplier Tariff
3 attached to my direct testimony. (See PPL Electric Exhibit LN-1, p. 239.) In other words, the
4 existing Supplier Tariff's Competitive Billing Specifications Rider does not provide
5 requirements for a Rate Ready billing scenario in the provision referenced by Mr. Lacey.
6 Therefore, Mr. Lacey should have the same concern with PPL Electric's existing Supplier
7 Tariff. I believe that this further underscores the need to update the Company's Supplier
8 Tariff.

9 To address Mr. Lacey's concern, the Company would be willing to include the
10 following revisions (shown in bold) as part of its compliance tariff filing in this case:

11 The EGS ~~will calculate its customers' charges and will either will~~
12 **calculate and** send its customers' basic charges including date of
13 billing period, consumption, usage, rate and resulting calculation
14 ("EGS Charges") to PPL Electric **or will send PPL Electric the date**
15 **of billing period, consumption, usage, and rate for PPL Electric to**
16 **calculate the EGS Charges,** in accordance with the data transfer
17 procedures established by the Electronic Data Exchange Working
18 Group Standards. PPL Electric and an EGS may develop, for future
19 consideration, a fee structure to enable PPL Electric to include non-
20 basic EGS charges on a PPL Electric consolidated bill.

21
22 **VII. CONCLUSION**

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

24 A. Yes, it does.

WITNESS: Lisa Norden

PPL Electric Utilities Corporation
Response to the Set VI Data Requests of the
Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania
(CAUSE-PA)
Dated October 29, 2025
Docket No. R-2025-3057164

CAUSE-PA VI-19 Please describe PPL's current policies and procedures regarding enrollment of a shopping customer in its CAP. Please provide a copy of all current written policies, procedures, memoranda, training materials, call scripts, and/ or other written documents which describe PPL's policies and procedures regarding enrollment of shopping customers in CAP.

PPL Electric Response As of June 1, 2025, for customers who are approved for PPL Electric's OnTrack program and are shopping with an electric generation supplier ("EGS"), the Company automatically notifies the EGS to submit a cancellation using a special code. This code indicates to the EGS that no early cancellation or termination fees may be charged to the customer. The paper assistance application includes language pointing out that a customer may not participate with a supplier if they are approved for OnTrack. If a customer applies online, a similar message is displayed. In both cases, the customer is advised that the Company will initiate the process to cancel the EGS.

Immediately upon approval, a 15-day hold is added to protect the customer's account from late payment charges, collection notices, or service terminations and to allow time for the cancellation request and submission to pass from the Company to the EGS and back to the Company. A letter is mailed to the customer which explains they have been approved for OnTrack but cannot remain with any EGS while enrolled in the program. The letter further explains that no action is required on the customer's part and that the EGS will not charge any early cancellation or termination fees because of the customer's OnTrack approval.

A note is automatically added to the account that the supplier cancellation request is being submitted in response to an OnTrack approval. Upon receipt of the cancellation from the EGS, an automated process returns the customer's account to default service. The OnTrack enrollment is then completed

WITNESS: Lisa Norden

automatically, and the normal OnTrack enrollment letter is sent to the customer.

See attachments:

- CAUSE-PA VI-19 Attachment 1 - DSP VI Changes for iQor Training
- CAUSE-PA VI-19 Attachment 2 - Memo to CBOs New Process - PPL Automatically Canceling Supplier
- CAUSE-PA VI-19 Attachment 3 - Online Message PPL EGS Drop
- CAUSE-PA VI-19 Attachment 4 - Online Application Email PPL Drop EGS
- CAUSE-PA VI-19 CONFIDENTIAL Attachment 5 - OnTrack Overview
- CAUSE-PA VI-19 Attachment 6 - OnTrack Application Live Agent

DSP VI Changes for iQor Training

Drop Supplier Process Change for OnTrack

Since 6/1/2021, customers cannot have an active Electric Generation Supplier and be enrolled in OnTrack.

The current process requires that a customer who has been approved for OnTrack and has an active electric generation supplier contact their supplier within 15 days of OnTrack approval to request a cancellation.

If the supplier drop occurs within 15 days, the OnTrack application status changes to Enrolled and the customer is enrolled in the program. If there is no supplier drop after 15 days, the OnTrack application status changes to “Rejected.”

Effective 6/1/2025, if a customer is approved for OnTrack and has an electric Generation Supplier on the account, PPL will automatically remove the supplier. There will be no early cancellation or termination fees charged by the supplier if the removal reason is for OnTrack enrollment.

The new process will be as follows:

- Customer applies for OnTrack.
- Agency reviews and approves application.
- If there is a supplier on the account, the application goes into a “**Pre-Enroll Initiated**” status in REP.
- A grace extension is added to the account, with new comments: “**PPL will submit supplier removal to allow completion of pending OT enrollment.**”
- An automated process drops the supplier (return to default service) in CSS
- A letter is mailed to the customer: “**OnTrack Enroll – PPL Drop Supplier**” which advises customer PPL will automatically request the supplier drop and that supplier will not charge any early cancellation or termination fees.

Dear ##CustomerName##;

Your application for our OnTrack program is approved. Among other benefits, OnTrack will lower your monthly electric bill payments and help you erase any debt you may owe us.

To participate in OnTrack, you cannot have an electric generation supplier. We will cancel your contract with your supplier automatically to complete your enrollment. You won't have to pay any cancellation or early termination fees. Instead, you will receive default supply through PPL Electric.

We are committed to managing energy prices and securing the lowest cost of energy for our customers under the current approved plan. The PPL Electric default rate, or Price to Compare, changes twice per year on June 1 and December 1 and is the price you'll pay without a supplier.

We want to assure you that we've taken steps to prevent any collection activity, such as late payment charges, collection notices or service termination, while we request a cancellation from your supplier.

Your estimated OnTrack payment amount will be \$##OTInstallment##. Once the supplier is removed from your account, we will enter your OnTrack agreement. We'll also send you a welcome letter, which will include all the information you need to be successful in the program.

Again, we are excited to welcome you to OnTrack.

Sincerely,

PPL Electric Utilities

- There will now be two contacts related to the supplier drop: one to show the supplier name and effective date, and one to indicate that the drop occurred as a result of the approved OnTrack application.

Contacted	Type	User Name
04/25/25	Customer Choice Drop	ISSUED BY BATCH PROCESS
04/25/25	Customer Choice Drop	SYSTEM SYSTEM
04/23/25	Correspondence - General	CSLET
04/23/25	ONTRACK ENROLLMENT PENDING	SELF SERVICE USER
04/23/25	SC - GRADE EXTENSION	EANDUJAR
04/23/25	Financial Statement Added	EANDUJAR

Contact Information

Name: SYSTEM GENERATED

Date: 04/25/25 Time: 09:36 AM

Phone: 610 774-4743 Extension:

Type: Customer Choice Drop

☐ Critical Contact Expiration Date: / /

Comments:

Supplier dropped on 2025-04-30 - CleanChoice Energy

Contacted	Type	User Name
04/25/25	Customer Choice Drop	ISSUED BY BATCH PROCESS
04/25/25	Customer Choice Drop	SYSTEM SYSTEM
04/23/25	Correspondence - General	CSLET
04/23/25	ONTRACK ENROLLMENT PENDING	SELF SERVICE USER
04/23/25	SC - GRADE EXTENSION	EANDUJAR
04/23/25	Financial Statement Added	EANDUJAR

Contact Information

Name: SYSTEM GENERATED

Date: 04/25/25 Time: 09:36 AM

Phone: 1 - Extension:

Type: Customer Choice Drop

☐ Critical Contact Expiration Date: / /

Comments:

CUSTOMER WAS DROPPED FROM SUPPLIER DUE TO ONTRACK ENROLLMENT

- Once the supplier cancellation is complete, the OnTrack enrollment will proceed as normal, and the regular enrollment letter will be sent to the customer.

Call handling: If trained in OnTrack you will continue to take applications by phone as you do now. The only change is that rather than advising a customer who has a supplier to contact them to cancel, you may now let the customer know that PPL will take care of the cancellation for them automatically.

Do not offer to remove the supplier for a customer who is applying for OnTrack or tell the customer to contact the supplier themselves. Only cancellations submitted by PPL

automatically to the supplier as part of the OnTrack enrollment process can be assured of not being charged early cancellation fees.

For customers *outside* the OnTrack enrollment process who wish to cancel or remove their supplier, you should continue to follow current return to default service processes.

<https://pplcorp.sharepoint.com/mcas.ms/teams/Einstein/2013SitePages/Dropping%20a%20Supplier.aspx>

SOP Ending

Customers may enroll in the Standard Offer Program with a participating supplier at a 7% discount off PPL's Price to Compare through **May 31, 2025**. After that date, the Standard Offer Program will no longer be available. The Standard Offer scripting will no longer be provided at the end of a customer call.

Time of Use and Low-Income Customers

As part of the DSP VI proceedings, PPL was directed to encourage low-income customers who are considering enrolling in PPL's Time of Use (TOU) Rate that there are also special payment plans and assistance programs to help make their bills more affordable.

Call handling: If a customer is seeking payment assistance, or has been identified as Level 1 income group, and asks about TOU, please follow the Pay Assistance call flow and refer customers to any programs for which they may be eligible. Continue to transfer the call to the Time of Use queue, as you do today.

From: [Kelly, Kristen M](#)
To: New Process - PPL Automatically Canceling Supplier
Cc: Monday, May 12, 2025 7:58:00 AM
Subject: [image001.png](#)
Date:
Attachments:

Good morning, everyone.

I'd like to share some news about a new process related to OnTrack. Effective starting **June 1, 2025**, customers will no longer need to contact their supplier to cancel their contract prior to OnTrack enrollment.

PPL has received regulatory approval to notify suppliers directly to cancel their contract with the customer, **with no cancellation or early termination fees**. This process will be automated and will work similarly to the automated Stop Budget process.

You will continue to review and approve applications as you do now. When the system identifies that an approved customer is enrolled with a supplier, it will put the application into Pre-Enroll Initiated status and tag the application "Awaiting Supplier Drop," as it does today.

However, instead of the customer needing to act, PPL will electronically notify the supplier of the cancellation, using a special code so that the supplier does not charge any fees to the customer.

The customer will receive a letter explaining that they are approved for OnTrack, PPL will cancel their supplier for them, and that the enrollment will not be completed until the supplier is removed.

Once the supplier has been removed from the account, the enrollment will be completed as normal, and the OnTrack enrollment letter will be issued to the customer. **The 15-day drop period will be eliminated**. The system will check the account daily until the supplier is removed. In most cases, the cancellation should only take a few business days.

We are hopeful that this new process will make the enrollment process simpler for our customers, reduce follow-up calls, and increase our enrollment success rate.

Please let me know if you have any questions.

Have a great week!

Best regards,

Kristen Kelly | [Regulatory Programs Manager](#)
Regulatory Programs

Contact Preferences

QUAKERTOWN, PA 18951

Account Number: [Setup Account](#)

To qualify for OnTrack, you cannot have an electricity supplier.

If you qualify for OnTrack and have an electricity supplier, PPL will cancel your contract with them automatically. You won't have to pay any cancellation or early termination fees.

Primary Phone Number

(610)

Alternate Phone Number

() - -

Please send me program information by:

☐ Email ☐ U.S. Mail

Email Address

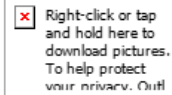
.com

Cancel

Save and Continue

PPL Electric Utilities Account Activity

[Home](#) [My Account](#) [Ways to Save](#) [About Us](#) | [Sign in](#)



Confirmation: Application received

Thank you for submitting your OnTrack application online. You can check your status on your Account Summary.

Your application will be reviewed by the following agency:

Community Action Partnership of Lancaster County	601 S. Queen Street Lancaster, PA 17603	Phone: 717-299-7301 Email: OnTrack@caplanc.org

If you chose to mail your income documents later, send them by U.S. Mail or email to the agency's listed address. Your application cannot be processed until your proof of income is received. Please make sure you write your PPL account number, name, and address on each proof of income document before submitting.

To qualify for OnTrack, you cannot have an electricity supplier. If you qualify for OnTrack and have an electricity supplier, PPL will cancel your contract with them automatically. You won't have to pay any cancellation or early termination fees.

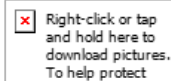
Manage Your Account Online

[Sign in to your online profile](#) to manage your PPL Electric Utilities account online.



Please do not reply to this automated email. This mailbox is not monitored.

Please visit the [PPL Electric Utilities website](#) for the latest news and services.



This folder is up to date. Connected to Microsoft Exchange



OnTrack Application – Live Agent Reference Guide (6/1/2025)



| CS Education Services

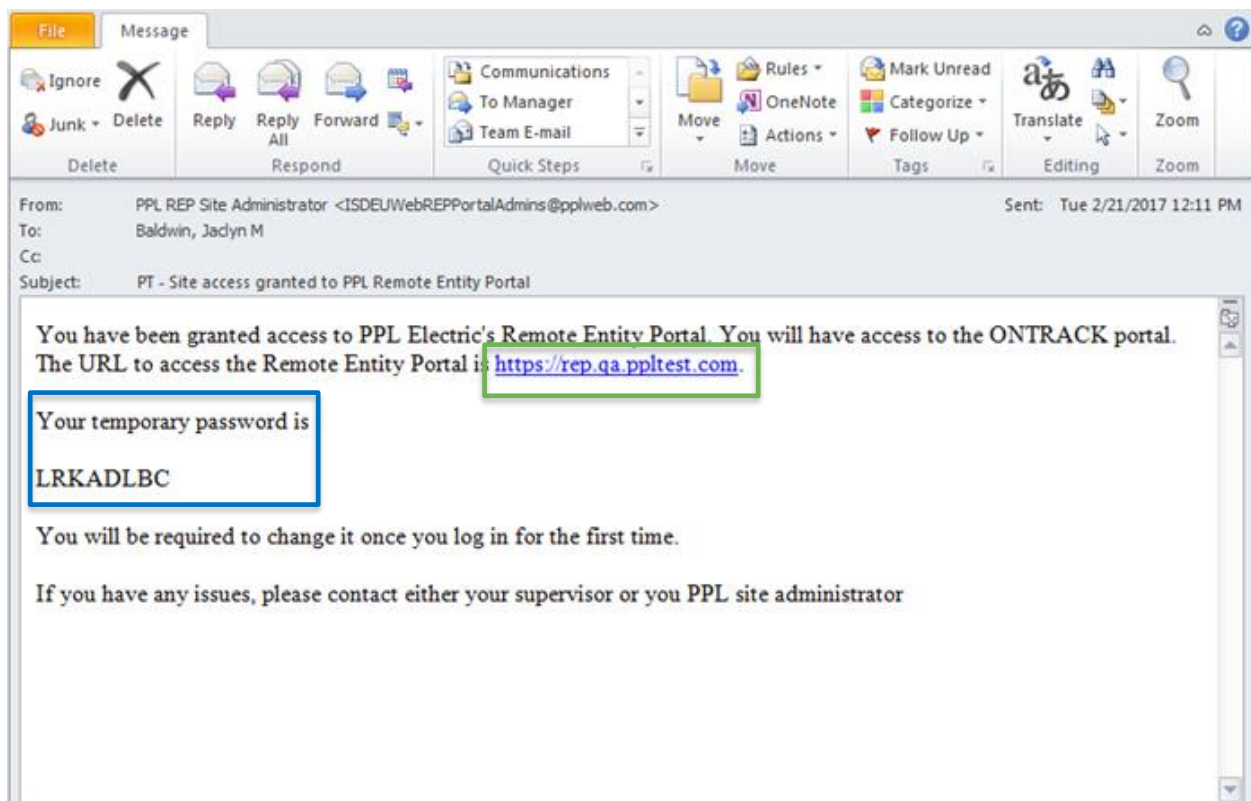
Introduction

Previously, OnTrack applications could be filled out and submitted via U.S. Mail or online. Customers will be offered the additional option of providing the information to a live agent, who will complete the application and submit it to the agency via the PPL Remote Entity Portal (REP). The application will then be reviewed by the agency located nearest to the customer who is applying.

The Remote Entity Portal (REP) is used in various ways by many people. You will only be concerned about populating the OnTrack application for the customer you have on the phone.

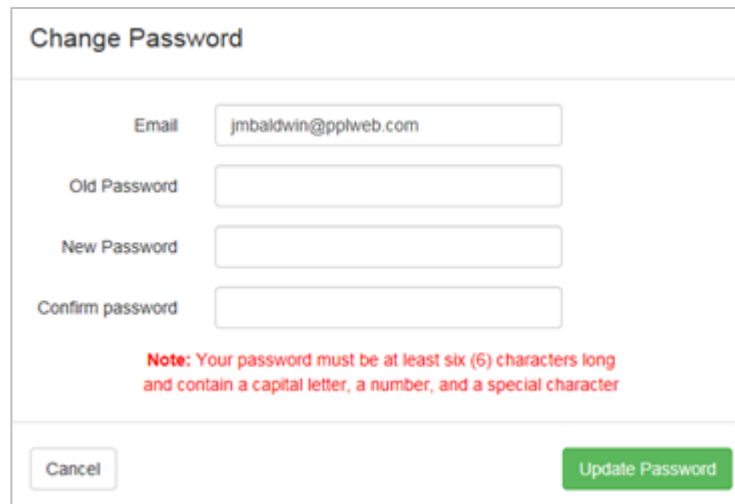
Access REP – first time users:

New OnTrack Portal users will receive an email with a temporary password and a link to the portal.



Customer Service Educational Services

1. Place the URL in your browser's search line: <https://rep.qa.ppltest.com/REP> or click on it here.
2. Enter your PPL email address in the Email address box.
3. Enter the temporary password in the Password box.
4. Click Login.
 - You will be prompted to enter your temporary password again, along with your new password.
 - Follow the steps to change your password and continue to log in.



Change Password

Email

Old Password

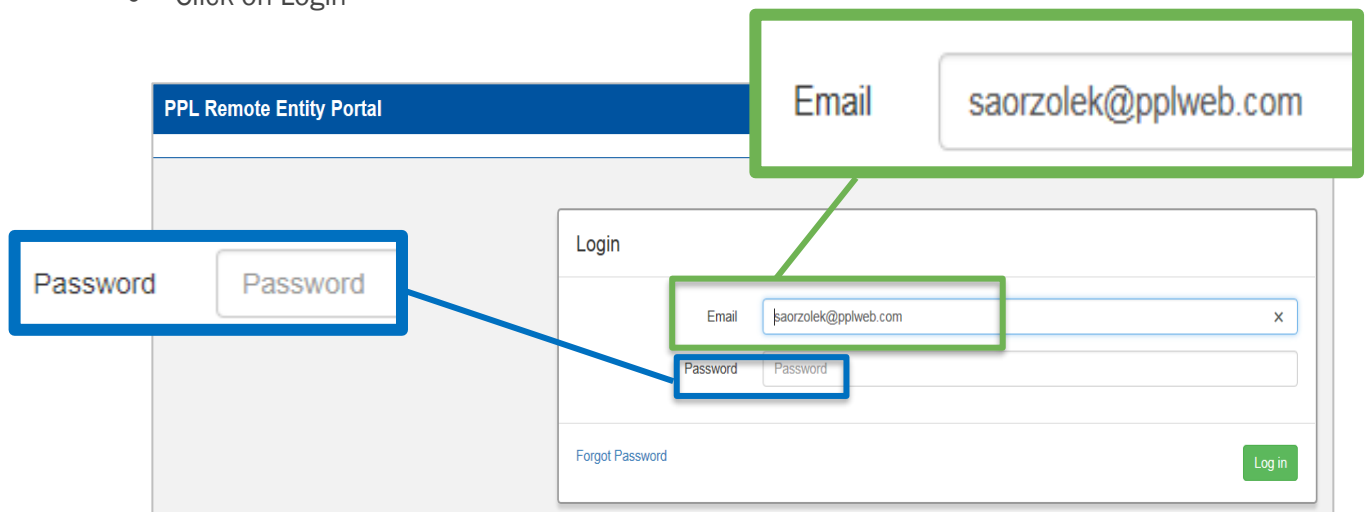
New Password

Confirm password

Note: Your password must be at least six (6) characters long and contain a capital letter, a number, and a special character

Access REP – Login Page:

1. To sign into the OnTrack Portal, place the URL in your browser's search line: <https://rep.prod.pplweb.com> or click on it here.
2. On the Login page
 - Enter your PPL email address in the Email address box.
 - Enter your password in the Password box
 - Click on Login



PPL Remote Entity Portal

Email

Login

Email

Password

Annotations: A green box highlights the Email field in the top right. A blue box highlights the Password field in the bottom left. A green box highlights the Email field in the bottom right. A blue box highlights the Password field in the bottom right.

Search for Bill Account

Enter the bill account number on the Search form without a hyphen. (You can also search by the other criteria. However, since you are taking OnTrack application information for a specific account, the search should be for that account number only.)

- Click Search Now.

The image shows a web form titled "Search". It contains several input fields: "Bill Account", "Meter #", "SSN", "Phone #", "Customer Name", "Address", and "Zip Code". The "Bill Account" field is highlighted with a green border, and a green callout box labeled "Bill Account" points to it. Below the input fields are two buttons: "Reset Search" and "Search Now". The "Search Now" button is highlighted with a blue border, and a blue callout box labeled "Search Now" points to it.

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The bill account information will automatically populate on an Account Summary page.

Account Activation Date	06/01/2016
Service Address	1001 S. 10TH AVE. APT. 101 BETHLEHEM, PA 18015
Phone Number	(484) 655-7512
Alt Phone Number	Not Available
Revenue Class	Res-Elec Heated Home
Operating Center	Bethlehem

PPL Remote Entity Portal - OnTrack

You are logged in as **OnTrack Portal**

Start a new search | [New OnTrack Application](#) | [OnTrack Applications](#)

[My Profile \(sazozolek@pplweb.com\)](#)

Account Summary

PPL Bill Account #: 000011-001000

Account Activation Date	06/01/2016
Service Address	1001 S. 10TH AVE. APT. 101 BETHLEHEM, PA 18015
Phone Number	(484) 655-7512
Alt Phone Number	Not Available
Revenue Class	Res-Elec Heated Home
Operating Center	Bethlehem

Total Account Balance: \$3,061.75

Financial Summary

Account Status	Active
Collection Status	Not in Collections
Current Bill Amount	\$223.00
Current Bill Due Date	2/22/2018
Enrolled in OnTrack	No
OnTrack Reinstate Amount	\$0.00
Enrolled in Budget Billing	Yes
Budget Billing Status	Pending Stop
Current Budget Amount	\$0.00
Security Deposit	\$0.00
Deposit Status	Deposit Waived
Enrolled in AutoPay	No

Active Services

Service Type	Rate	Price To Compare	Rate Effective Date
Electric Service	RSO Distribution	7.463¢	06/09/2016

Active Services

Service Type	Rate	Price To Compare	Rate Effective Date
Electric Service	RSO Distribution	7.463¢	06/09/2016

Customer Service Educational Services

PPL Remote Entity Portal - OnTrack

You are logged in as OnTrack Portal

Start a new search | New OnTrack Application | OnTrack Applications

Account Summary

Total Account Balance: ? \$3,061.75

Financial Summary

Account Status	Active
Collection Status	Not in Collections
Current Bill Amount	\$223.00
Current Bill Due Date	2/22/2018
Enrolled in OnTrack	No
OnTrack Reinstatement Amount	\$0.00
Enrolled in Budget Billing	Yes
Budget Billing Status	Pending Stop
Current Budget Amount	\$0.00
Security Deposit	\$0.00
Deposit Status	Deposit Waived
Enrolled in AutoPay	No

Click on New OnTrack Application, in the upper right corner. (NOTE: If the correct account does not pop up, you can click on Start a New Search and re-enter the correct number.)

PPL Remote Entity Portal - OnTrack

You are logged in as OnTrack Portal

Start a new search | New OnTrack Application | OnTrack Applications

Total Account Balance: ? \$3,061.75

Financial Summary

Account Status	Active
Collection Status	Not in Collections
Current Bill Amount	\$223.00
Current Bill Due Date	2/22/2018
Enrolled in OnTrack	No
OnTrack Reinstatement Amount	\$0.00
Enrolled in Budget Billing	Yes
Budget Billing Status	Pending Stop
Current Budget Amount	\$0.00
Security Deposit	\$0.00
Deposit Status	Deposit Waived
Enrolled in AutoPay	No

Start a new search | **New OnTrack Application**

Phone Number (484) 888-1812

Alt Phone Number Not Available

Revenue Class Res-Elec Heated Home

Operating Center Bethlehem

Active Services

Service Type	Rate	Price To Compare	Rate Effective Date
Electric Service	RSO Distribution	7.463¢	06/09/2016

Enter Contact Preferences Information

You must populate all required fields. Existing information in these areas will auto-populate.

The image shows a screenshot of the 'OnTrack Application' form, specifically the 'Contact Preferences' section. The form is titled 'OnTrack Application' with a 'Status: Draft' indicator in the top right corner. The 'Contact Preferences' section includes fields for 'Name', 'Address', and 'Account'. Below these are fields for 'Primary Phone Number (Required)', 'Alternate Telephone Number', and a section for 'Please send me program information by: (Required)' with radio buttons for 'Email' and 'U.S. Mail'. An 'Email address:' field is also present. Callouts are used to highlight specific areas: a green box labeled 'Name, address' points to the 'Name' and 'Address' fields; a blue box labeled 'Phone' points to the 'Primary Phone Number' field; and an orange box labeled 'Information Delivery' points to the 'Please send me program information by' section.

Enter Household Member(s) Income

Choose employment status for head of household. This may or may not be the ratepayer on the account.

The image shows a screenshot of the 'Household Members - Income' form. The form has a section titled 'Employment status for head of household (Required)' with a dropdown menu. The dropdown menu is open, showing a list of options: 'Full-Time Employment (35 or more hours/week)', 'Part-Time Employment (34 or fewer hours/week)', 'Unemployed worker (currently not employed)', 'Retired', 'Homemaker', 'Student', and 'Other'. A callout box labeled 'Phone' points to the 'Primary Phone Number' field in the 'Contact Preferences' section. Another callout box labeled 'Information Delivery' points to the 'Please send me program information by' section. The form also includes a 'Total Household Income: \$0.00 per month' field.

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Click on Add Person to populate the income for one of the household's occupants.

Household Members - Income

Employment status for head of household (Required)

Select Employment Status ☐

Add Person

Total Household Income: \$0.00 per month

Add Person

- You will need to fill in an income form for each person in the household, regardless of income. If the income is zero, you must put zero in the Salary field for it to record properly.

First Name, Last Name, Age

Person 1

First Name (Required) Last Name (Required) Age (Required)

Monthly Income

0.00 [Hide Income Details](#)

Salary (gross, before taxes) \$ per month

SSI or SSD \$ per month

Child Support \$ per month

Cash Assistance (DPW - not including food stamps) \$ per month

Unemployment \$ per month

Pension and/or Social Security \$ per month

Workers Compensation and/or Disability \$ per month

Other \$ per month

Total Income \$0.00 per month

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The Total Income will automatically populate when you have completed logging the income for that person.

Monthly Income

2000.00

Person 1

First Name (Required)

Last Name (Required)

Age (Required)

Monthly Income

2000.00

Hide Income Details

Salary (gross, before taxes)	\$	2000.00	per month
SSI or SSD	\$		per month
Child Support	\$		per month
Cash Assistance (DPW - not including food stamps)	\$		per month
Unemployment	\$		per month
Pension and/or Social Security	\$		per month
Workers Compensation and/or Disability	\$		per month
Other	\$		per month
Total Income		\$2000.00 per month	

Salary (gross, before taxes)	\$	2000.00	per month
SSI or SSD	\$		per month
Child Support	\$		per month
Cash Assistance (DPW - not including food stamps)	\$		per month
Unemployment	\$		per month
Pension and/or Social Security	\$		per month
Workers Compensation and/or Disability	\$		per month
Other	\$		per month
Total Income		\$2000.00 per month	

Income Documents

When you have captured the income for all household occupants, scroll down to the Income Documents section and read it to the customer.

- For over-the-phone applications, the customer can only mail in proof of income. (Notice the auto-default is to mail.)

Income Documents

In order to process your application, you must provide proof of all household income that was listed on the previous page.

☒ I will mail to agency later

Please mail your documents to the agency listed below. Write your bill account number, customer name and address on each page.

Agency Mailing Address

TREHAB, Inc.
100 4th Street Suite 20
Honesdale, PA 18431
Phone: 570-253-8941
Email: PPLOnTrack@trehab.org

☐ I have my proof of income ready to upload

Expenses

Category consists of two sections:

- Living Expenses
- Utilities

In both sections, populate all information provided by the caller. Even if customer states they pay zero rent or mortgage, you must enter the number zero (0). This cannot be left blank.

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Living Expenses

Do you Rent or Own? (Required)

☐ Mortgage
 ☐ Rent

Rent or Mortgage Payment

If you live in subsidized or Section 8 housing, please enter the amount that you pay per month.

\$

per month

Food	\$	0.00	per month
Phone	\$	0.00	per month
Medical	\$	0.00	per month
Home or Rental Insurance	\$	0.00	per month
Cable	\$	0.00	per month
Child Care	\$	0.00	per month

Electric field is auto-populated with current budget amount. Total expenses will display.

Utilities

What type of installed heating does your home have ? (Required)

☒ Fuel Oil/Kerosene
☐ Utility Gas
☐ Bottled Gas/Propane
☐ Electric
☐ Coal
☐ Wood
☐ Other

Electric	\$	82.00	per month
Coal	\$	0.00	per month
Gas	\$	0.00	per month
Oil	\$	600	per month
Propane	\$	0.00	per month
Wood	\$	0.00	per month
Water/Sewer	\$	0.00	per month
Other Fuel	\$	0.00	per month

Total Expenses

Total Expenses: \$2952.00 per month

Property Information

The screenshot shows the 'Property Information' section of a form. It includes a dropdown menu for 'Type of Home' with a callout showing options: Select Home Type, Single, Mobile Home, Row Home, Apartment, and Town Home. Below this is a text input for 'Year Home Built'. Another dropdown menu for 'Does your home have an electric water heater?' has a callout showing options: Select One, Yes, No, and Don't Know.

Property Information

Type of Home
Select Home Type

Year Home Built

Does your home have an electric water heater?
Select One

Type of Home
Select Home Type
Single
Mobile Home
Row Home
Apartment
Town Home

Does your home have an electric water heater?
Select One
Yes
No
Don't Know

Landlord Information

LL information is not mandatory to submit an application, but please do not skip. Instead, encourage customer to provide the information, which may be used to help determine the customer's eligibility for WRAP.

The screenshot shows the 'Landlord Information' section of a form. It includes text input fields for Landlord Name, Landlord Address, City, State, and Zip Code. Below these is a section titled 'Please provide at least one of the following contact methods for your landlord' with input fields for Landlord Phone Number and Landlord Email Address.

Landlord Information

Landlord Name

Landlord Address

City

State

Zip Code

Please provide at least one of the following contact methods for your landlord

Landlord Phone Number

Landlord Email Address

Bill Due Date

This question may be in the application, as it can be turned off/on depending on the business needs. If the question is displayed say: DO NOT OFFER A DUE DATE CHANGE AT THIS TIME.

Supplier Information

If a customer is approved for OnTrack and has an Electric Generation Supplier on the account, PPL will automatically remove the supplier. There are to be no early cancellation or termination fees charged by the supplier if the removal reason is for OnTrack enrollment.

The new process will be as follows:

- Customer applies for OnTrack.
- Agency reviews and approves application.
- If there is a supplier on the account, the application goes into a “Pre-Enroll Initiated” status.
- A grace extension is added to the account, along with an account contact: “PPL will submit supplier removal to allow completion of pending OT enrollment.”
- Automated process is initiated to drop supplier (return to default service) in CSS
- Customer is mailed a letter: “OnTrack Enroll – PPL Drop Supplier” which advises customer PPL will automatically request the supplier drop and that supplier will not charge any early cancellation or termination fees.
- Once the supplier drop is completed, the OnTrack application status changes to Enrolled and the customer is enrolled in the program.

Consent

All three of the consent questions must be answered, according to the caller's response.

Consent

If you are enrolled in OnTrack, PPL Electric Utilities will provide you with a reduced bill and debt forgiveness (you don't have to pay back any overdue money you owe PPL). It will be your responsibility to pay your bill on-time each month, control your usage to the best of your ability, and contact us if anything changes in your life that affects your financial situation or the number of people in your home.

Do you agree? (Required) ☐ Yes ☐ No

You are aware that you could be penalized for lying or withholding information.

Do you agree? (Required) ☐ Yes ☐ No

All the information you entered above is true and accurate to the best of your ability.

Do you agree? (Required) ☐ Yes ☐ No

Submit Application

Once the application is completed, clicking on Submit Application in upper right corner of web page.

Account Search

OnTrack Applications

Save Application

Submit Application

Status: Draft

Submit Application

Customer Service Educational Services

Clicking Submit Application will produce a notation in the upper right that shows the application is Pending Review.

The screenshot shows the 'OnTrack Applications' section of a web interface. At the top, there are three buttons: 'Account Search', 'OnTrack Applications', and 'Save Application'. Below these, a 'Tag:' dropdown menu is set to a power icon. Below the tag, the 'Status:' is displayed as 'Pending Review'. A blue box highlights the 'Tag:' and 'Status:' area, and a blue arrow points from this box to a larger, more detailed view of the same area on the right. The detailed view shows the 'Tag:' dropdown with the power icon and the 'Status:' as 'Pending Review' in a dark grey box.

DO NOT Save the application – ALWAYS SUBMIT!

Document the account appropriately.

Customer Claims Zero Income

If a customer claims zero income, you will need to fill out this form while on the phone. Agency will ask for proof of what the customer is receiving to meet their basic necessities.

Income Documents

☐ Mail Zero Income Form

Zero Income

We notice that you did not specify any income. In order to be enrolled in the OnTrack program, we need to know how you are meeting your living expenses. Tell us as much as possible about your situation and why you have zero income. Please explain and answer the following questions in the text box below.

How long have you been without income? (Required)

When do you expect to have some sort of income? (Required)

How are you meeting your basic necessities like food, shelter and utilities? (Required)

Are there any other adults in your home receiving income? (Required)

If so, what type of income are they receiving, and how much? (Required)

Please provide information that is true and accurate. Providing false information to PPL Electric Utilities is grounds for denial and dismissal of your application and participation in the OnTrack program.

☐ I have my proof of income ready to upload

Customer Service Educational Services

WITNESS: Lisa Norden

PPL Electric Utilities Corporation
Response to the Set VII Data Requests of the
Office of Consumer Advocate (OCA)
Dated October 27, 2025
Docket No. R-2025-3057164

OCA VII-19 Provide the monthly number for each type of payment plans negotiated with Pennsylvania residential customers from January 2023 to the present month.

PPL Electric See OCA VII-19 Attachment 1.
Response

19. Provide the monthly number for each type of payment plans negotiated with Pennsylvania residential customers from January 2023 to the present month.

Sum of Agreements_Negotiated	Column Labels							
Row Labels	Catch-Up	Non_Catch-Up	PUC Catch-Up	PUC Non-Catch-Up	Reconnection	Reconnection Two	Transfer Agreement	Grand Total
2023-01	14,501	7,079	76	333	222	25	35	22,271
2023-02	10,157	5,445	40	248	67	0	11	15,968
2023-03	12,200	6,998	22	277	93	0	13	19,603
2023-04	9,299	5,734	29	225	64	0	22	15,373
2023-05	10,087	5,898	32	287	68	0	24	16,396
2023-06	9,621	5,453	51	247	41	0	27	15,440
2023-07	18,027	17,803	78	462	300	33	26	36,729
2023-08	21,242	13,586	106	894	1,475	539	25	37,867
2023-09	24,552	11,686	112	3,020	1,214	486	24	41,094
2023-10	25,946	10,485	114	3,206	1,812	796	44	42,403
2023-11	22,962	9,121	133	2,595	1,497	751	37	37,096
2023-12	15,533	6,432	74	876	177	29	36	23,157
2024-01	17,461	7,489	114	980	259	26	46	26,375
2024-02	16,875	8,128	161	992	214	17	37	26,424
2024-03	21,676	11,279	214	1,751	250	23	40	35,233
2024-04	31,402	14,128	159	967	2,965	1,401	50	51,072
2024-05	27,589	8,919	109	860	2,783	1,555	58	41,873
2024-06	27,474	7,226	84	706	1,807	1,606	50	38,953
2024-07	31,806	8,668	87	789	1,845	1,525	78	44,798
2024-08	29,642	8,897	92	676	1,957	1,649	60	42,973
2024-09	27,313	9,418	67	506	2,194	1,676	54	41,228
2024-10	28,619	9,626	82	917	2,161	1,856	68	43,329
2024-11	22,456	6,655	64	617	1,082	1,103	58	32,035
2024-12	17,288	5,654	61	455	260	60	48	23,826
2025-01	16,429	7,082	73	506	195	12	39	24,336
2025-02	15,465	8,412	68	417	263	27	33	24,685
2025-03	21,664	14,103	103	564	411	13	32	36,890
2025-04	27,442	14,945	73	716	2,840	1,595	19	47,630
2025-05	26,475	9,107	39	891	2,532	1,568	35	40,647
2025-06	28,901	8,349	17	528	1,871	1,535	44	41,245
2025-07	30,625	9,446	27	433	1,724	1,430	47	43,732
2025-08	28,962	10,138	28	411	1,956	1,680	61	43,236
2025-09	32,153	11,362	31	429	1,996	1,625	65	47,661
Grand Total	721,844	304,751	2,620	27,781	38,595	24,641	1,346	1,121,578

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Year_Month	AGREEMENT_TYPE	Agreements_Negotiated
2023-01	Catch-Up	14501
2023-01	Non_Catch-Up	7079
2023-01	PUC Catch-Up	76
2023-01	PUC Non-Catch-Up	333
2023-01	Reconnection	222
2023-01	Reconnection Two	25
2023-01	Transfer Agreement	35
2023-02	Catch-Up	10157
2023-02	Non_Catch-Up	5445
2023-02	PUC Catch-Up	40
2023-02	PUC Non-Catch-Up	248
2023-02	Reconnection	67
2023-02	Transfer Agreement	11
2023-03	Catch-Up	12200
2023-03	Non_Catch-Up	6998
2023-03	PUC Catch-Up	22
2023-03	PUC Non-Catch-Up	277
2023-03	Reconnection	93
2023-03	Transfer Agreement	13
2023-04	Catch-Up	9299
2023-04	Non_Catch-Up	5734
2023-04	PUC Catch-Up	29
2023-04	PUC Non-Catch-Up	225
2023-04	Reconnection	64
2023-04	Transfer Agreement	22
2023-05	Catch-Up	10087
2023-05	Non_Catch-Up	5898
2023-05	PUC Catch-Up	32
2023-05	PUC Non-Catch-Up	287
2023-05	Reconnection	68
2023-05	Transfer Agreement	24
2023-06	Catch-Up	9621
2023-06	Non_Catch-Up	5453
2023-06	PUC Catch-Up	51
2023-06	PUC Non-Catch-Up	247
2023-06	Reconnection	41
2023-06	Transfer Agreement	27
2023-07	Catch-Up	18027
2023-07	Non_Catch-Up	17803
2023-07	PUC Catch-Up	78
2023-07	PUC Non-Catch-Up	462

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2023-07	Reconnection	300
2023-07	Reconnection Two	33
2023-07	Transfer Agreement	26
2023-08	Catch-Up	21242
2023-08	Non_Catch-Up	13586
2023-08	PUC Catch-Up	106
2023-08	PUC Non-Catch-Up	894
2023-08	Reconnection	1475
2023-08	Reconnection Two	539
2023-08	Transfer Agreement	25
2023-09	Catch-Up	24552
2023-09	Non_Catch-Up	11686
2023-09	PUC Catch-Up	112
2023-09	PUC Non-Catch-Up	3020
2023-09	Reconnection	1214
2023-09	Reconnection Two	486
2023-09	Transfer Agreement	24
2023-10	Catch-Up	25946
2023-10	Non_Catch-Up	10485
2023-10	PUC Catch-Up	114
2023-10	PUC Non-Catch-Up	3206
2023-10	Reconnection	1812
2023-10	Reconnection Two	796
2023-10	Transfer Agreement	44
2023-11	Catch-Up	22962
2023-11	Non_Catch-Up	9121
2023-11	PUC Catch-Up	133
2023-11	PUC Non-Catch-Up	2595
2023-11	Reconnection	1497
2023-11	Reconnection Two	751
2023-11	Transfer Agreement	37
2023-12	Catch-Up	15533
2023-12	Non_Catch-Up	6432
2023-12	PUC Catch-Up	74
2023-12	PUC Non-Catch-Up	876
2023-12	Reconnection	177
2023-12	Reconnection Two	29
2023-12	Transfer Agreement	36
2024-01	Catch-Up	17461
2024-01	Non_Catch-Up	7489
2024-01	PUC Catch-Up	114
2024-01	PUC Non-Catch-Up	980

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2024-01	Reconnection	259
2024-01	Reconnection Two	26
2024-01	Transfer Agreement	46
2024-02	Catch-Up	16875
2024-02	Non_Catch-Up	8128
2024-02	PUC Catch-Up	161
2024-02	PUC Non-Catch-Up	992
2024-02	Reconnection	214
2024-02	Reconnection Two	17
2024-02	Transfer Agreement	37
2024-03	Catch-Up	21676
2024-03	Non_Catch-Up	11279
2024-03	PUC Catch-Up	214
2024-03	PUC Non-Catch-Up	1751
2024-03	Reconnection	250
2024-03	Reconnection Two	23
2024-03	Transfer Agreement	40
2024-04	Catch-Up	31402
2024-04	Non_Catch-Up	14128
2024-04	PUC Catch-Up	159
2024-04	PUC Non-Catch-Up	967
2024-04	Reconnection	2965
2024-04	Reconnection Two	1401
2024-04	Transfer Agreement	50
2024-05	Catch-Up	27589
2024-05	Non_Catch-Up	8919
2024-05	PUC Catch-Up	109
2024-05	PUC Non-Catch-Up	860
2024-05	Reconnection	2783
2024-05	Reconnection Two	1555
2024-05	Transfer Agreement	58
2024-06	Catch-Up	27474
2024-06	Non_Catch-Up	7226
2024-06	PUC Catch-Up	84
2024-06	PUC Non-Catch-Up	706
2024-06	Reconnection	1807
2024-06	Reconnection Two	1606
2024-06	Transfer Agreement	50
2024-07	Catch-Up	31806
2024-07	Non_Catch-Up	8668
2024-07	PUC Catch-Up	87
2024-07	PUC Non-Catch-Up	789

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2024-07	Reconnection	1845
2024-07	Reconnection Two	1525
2024-07	Transfer Agreement	78
2024-08	Catch-Up	29642
2024-08	Non_Catch-Up	8897
2024-08	PUC Catch-Up	92
2024-08	PUC Non-Catch-Up	676
2024-08	Reconnection	1957
2024-08	Reconnection Two	1649
2024-08	Transfer Agreement	60
2024-09	Catch-Up	27313
2024-09	Non_Catch-Up	9418
2024-09	PUC Catch-Up	67
2024-09	PUC Non-Catch-Up	506
2024-09	Reconnection	2194
2024-09	Reconnection Two	1676
2024-09	Transfer Agreement	54
2024-10	Catch-Up	28619
2024-10	Non_Catch-Up	9626
2024-10	PUC Catch-Up	82
2024-10	PUC Non-Catch-Up	917
2024-10	Reconnection	2161
2024-10	Reconnection Two	1856
2024-10	Transfer Agreement	68
2024-11	Catch-Up	22456
2024-11	Non_Catch-Up	6655
2024-11	PUC Catch-Up	64
2024-11	PUC Non-Catch-Up	617
2024-11	Reconnection	1082
2024-11	Reconnection Two	1103
2024-11	Transfer Agreement	58
2024-12	Catch-Up	17288
2024-12	Non_Catch-Up	5654
2024-12	PUC Catch-Up	61
2024-12	PUC Non-Catch-Up	455
2024-12	Reconnection	260
2024-12	Reconnection Two	60
2024-12	Transfer Agreement	48
2025-01	Catch-Up	16429
2025-01	Non_Catch-Up	7082
2025-01	PUC Catch-Up	73
2025-01	PUC Non-Catch-Up	506

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2025-01	Reconnection	195
2025-01	Reconnection Two	12
2025-01	Transfer Agreement	39
2025-02	Catch-Up	15465
2025-02	Non_Catch-Up	8412
2025-02	PUC Catch-Up	68
2025-02	PUC Non-Catch-Up	417
2025-02	Reconnection	263
2025-02	Reconnection Two	27
2025-02	Transfer Agreement	33
2025-03	Catch-Up	21664
2025-03	Non_Catch-Up	14103
2025-03	PUC Catch-Up	103
2025-03	PUC Non-Catch-Up	564
2025-03	Reconnection	411
2025-03	Reconnection Two	13
2025-03	Transfer Agreement	32
2025-04	Catch-Up	27442
2025-04	Non_Catch-Up	14945
2025-04	PUC Catch-Up	73
2025-04	PUC Non-Catch-Up	716
2025-04	Reconnection	2840
2025-04	Reconnection Two	1595
2025-04	Transfer Agreement	19
2025-05	Catch-Up	26475
2025-05	Non_Catch-Up	9107
2025-05	PUC Catch-Up	39
2025-05	PUC Non-Catch-Up	891
2025-05	Reconnection	2532
2025-05	Reconnection Two	1568
2025-05	Transfer Agreement	35
2025-06	Catch-Up	28901
2025-06	Non_Catch-Up	8349
2025-06	PUC Catch-Up	17
2025-06	PUC Non-Catch-Up	528
2025-06	Reconnection	1871
2025-06	Reconnection Two	1535
2025-06	Transfer Agreement	44
2025-07	Catch-Up	30625
2025-07	Non_Catch-Up	9446
2025-07	PUC Catch-Up	27
2025-07	PUC Non-Catch-Up	433

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OCA VII-19 Attachment 1- Payment Agreement Counts

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2025-07	Reconnection	1724
2025-07	Reconnection Two	1430
2025-07	Transfer Agreement	47
2025-08	Catch-Up	28962
2025-08	Non_Catch-Up	10138
2025-08	PUC Catch-Up	28
2025-08	PUC Non-Catch-Up	411
2025-08	Reconnection	1956
2025-08	Reconnection Two	1680
2025-08	Transfer Agreement	61
2025-09	Catch-Up	32153
2025-09	Non_Catch-Up	11362
2025-09	PUC Catch-Up	31
2025-09	PUC Non-Catch-Up	429
2025-09	Reconnection	1996
2025-09	Reconnection Two	1625
2025-09	Transfer Agreement	65

WITNESS: Lisa Norden

PPL Electric Utilities Corporation
Response to the Set VII Data Requests of the
Office of Consumer Advocate (OCA)
Dated October 27, 2025
Docket No. R-2025-3057164

OCA VII-20	Provide any analysis of the success or failure associated with each or any of the payment plans offered to residential customers.

PPL Electric Response	See OCA VII-20 Attachment 1 related to December 2024 Payment Agreement (PAG) offerings.

PA PUC Docket No. R-2025-3057164

Question:
PPL-EJA-III-I

Date of Response:
01/15/2026

Response Provided By:
Karl R. Rábago

Question

Reference EJA St. No. 1, p. 64. Mr. Rábago states that his “assumption is that 17% of the customer service call volume is related to turning on service and connecting customers to the grid, but in [his] experience the amount is probably less, especially with the low growth rates PPL Electric is experiencing.”

- a) Please provide all documents, analyses, and calculations relied upon by Mr. Rábago to develop his “assumption.”
- b) Please provide explain in detail why the “amount is probably less” based on his experience and provide all documents, analyses, and calculations relied upon by Mr. Rábago in reaching that conclusion and in responding to this discovery request.

Answer

a) Mr. Rábago has more than 35 years of experience in the utility regulatory field, as detailed in his resume submitted with his direct testimony. Exh. KRR-1. His experience includes leadership in a board and employee capacity of non-governmental organizations focused on utility consumer issues, including engagement with consumer advocates on the issues that face customers in securing and maintaining utility service. Mr. Rábago has also served as a utility executive with specific duties relating to engagement with consumers. Mr. Rábago’s experience is that customer enrollment processes today are largely automated and require less customer service engagement effort and time than do processes and services related to their level of demand, their ability to pay utility bills, and quality of service. *See* Jim Lazar, *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs*, Regulatory Assistance Project (Nov. 13, 2014), <https://www.raponline.org/knowledge-center/electric-utility-residential-customer-charges-and-minimum-bills-alternative-approaches-for-recovering-basic-distribution-costs/>.

PPL Electric reported that it does not track customer-related expenses so as to confirm or refute Mr. Rábago’s testimony, and so expert judgment is required. *See* PPL Electric Response to EJA-PPL-I-37. As noted in Mr. Rábago’s direct testimony, PPL Electric anticipates only marginal customer growth for customers taking distribution service, at a rate of less than one-half of one percent per year for the years between 2025-27. Based on his experience and these facts, Mr.

Rábago asserts that an assumption that 17% of customer service call volume is related to activities involving turning on service and connecting customers to the grid is reasonably assumed to be a high estimate.

b) Please see Mr. Rábago's response to PPL-EJA-III-1(a).

Pa. P.U.C. v. PPL Electric Utilities Corporation
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OCA Response to Interrogatories of PPL Electric Utilities Corporation
Set III to OCA

4. Reference OCA St. 8, pp. 81-82.
- a. Please explain in detail how Mr. Colton developed his proposed first outcome metric, apart from the New Jersey Board of Public Utilities (“NJBPU”) “recently adopt[ing]” these metrics.
 - b. Provide all documents and analyses relied upon by Mr. Colton in developing his proposed second outcome metric.
 - c. To the extent not already provided, please provide all documents issued by the NJBPU relied upon by Mr. Colton to determine that these improvement metrics were “recently adopted” by the NJBPU.
 - d. To Mr. Colton’s knowledge, did the NJBPU adopt any performance-base rates tied to the public utilities’ achievement of or failure to achieve these metrics? If so, please explain in detail what those performance-based rates are, and provide all documents relied upon by Mr. Colton in reaching that conclusion and in responding to this discovery request.
 - e. Please provide all information and materials in Mr. Colton’s or the OCA’s possession as to whether public utilities in New Jersey are on track to achieve these improvement metrics.
 - f. Please provide all analyses performed by Mr. Colton as to whether his proposed first outcome metric is actually achievable by PPL Electric.

RESPONSE DATE: January 12, 2026

RESPONDING WITNESS: Roger Colton

RESPONSE:

- a. The “First Outcome Metric” referenced in the question was identified by Mr. Colton as follows: “I recommend that the first outcome metric to be used should be an increase in the average monthly enrollment of PPL low-income customers in OnTrack.” (OCA Statement 8, at page 80). Data for electric utilities reported by BCS in the annual BCS report on Universal Service Programs and Collections Performance indicates that the outcome is reasonably achievable.
- b. The annual BCS reports on Universal Service Programs and Collections Performance can be accessed at https://www.puc.pa.gov/media/3433/2023_universal_service_report-final_rev041525.pdf
- c. The New Jersey BPU Order Modifying USF Program, in Docket No. QO24110853, IN THE MATTER OF A RATE DESIGN AND POLICY STUDY

REGARDING DRIVING EQUITY IN THE CLEAN ENERGY TRANSITION,
is publicly available on the web site of the New Jersey Board of Public Utilities.

- d. The New Jersey BPU Order Adopting Initial Decision and Stipulation, in Docket No. ER24110854 (November 21, 2025) is publicly available on the web site of the New Jersey Board of Public Utilities.
- e. The New Jersey order was adopted in June 2025 and no reporting on compliance with identified outcomes has yet occurred.
- f. See , Response to Question 4(b).

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OCA Response to Interrogatories of PPL Electric Utilities Corporation
Set III to OCA

5. Reference OCA St. 8, pp. 82-83.
- a. Please explain in detail how Mr. Colton developed his proposed second outcome metric.
 - b. Provide all documents and analyses relied upon by Mr. Colton in developing his proposed second outcome metric.
 - c. Please provide all analyses performed by Mr. Colton as to whether his proposed second outcome metric is actually achievable by PPL Electric.

RESPONSE DATE: January 12, 2026

RESPONDING WITNESS: Roger Colton

RESPONSE:

- a. The “Second Outcome Metric” referenced in the question was identified by Mr. Colton as follows: “. . .the following outcome metrics are recommended by which to measure PPL collections performance:
- A reduction by 10% each year for three years in the absolute number of defaulted residential deferred payment arrangements. For purposes of this outcome, a “defaulted payment arrangement” is a payment arrangement from which the customer has been removed for nonpayment prior to completion of all of the payments required under the payment arrangement to retire the arrears made subject to the arrangement;
 - A reduction by 10% each year for three years in the absolute number of residential nonpayment disconnections;
 - A reduction by 10% each year for three years in the number of residential customers who have, since April 1 of a given year, had their service disconnected for nonpayment and who, as of December 1 of that year, remain in their home with service not yet reconnected.
 - A reduction by 10% each year for three 1 years in the money at-risk to the Company. The total money owed and at-risk is the sum of money owed by customers in arrears and the money owed by customers on deferred payment agreements.” (OCA Statement 8, at 82 – 83).

Data for electric utilities reported by BCS in the annual BCS report on Universal Service Programs and Collections Performance, as well as data reported in the Commission’s Cold Weather Survey, indicates that the outcome is reasonably achievable. Mr. Colton’s experience and expertise in this field inform him when developing this second outcome metric.

- b. The annual BCS reports on Universal Service Programs and Collections Performance can be accessed at:

https://www.puc.pa.gov/media/3433/2023_universal_service_report-

[final_rev041525.pdf](#) The annual Cold Weather Survey reports by the Pennsylvania PUC can be accessed at: <https://www.puc.pa.gov/filing-resources/reports/electric-gas-water-cold-weather-survey-results/>

- c. See, Response to Question 5(b).

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OCA Response to Interrogatories of PPL Electric Utilities Corporation
Set III to OCA

6. Reference OCA St. 8, pp. 81-87.
 - a. Please provide all calculations performed by Mr. Colton as to the increased operation and maintenance (“O&M”) expenditures that would be required for PPL Electric to achieve his proposed outcome metrics.
 - b. Please provide all calculations performed by Mr. Colton as to the decreased operation and maintenance (“O&M”) expenditures that would accrue to PPL Electric for achieving his proposed outcome metrics.

RESPONSE DATE: January 12, 2026

RESPONDING WITNESS: Roger Colton

RESPONSE:

- a. Mr. Colton has not performed such a calculation.
- b. Mr. Colton has not performed such a calculation.

Pa. P.U.C. v. PPL Electric Utilities Corporation
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OCA Response to Interrogatories of PPL Electric Utilities Corporation
Set III to OCA

7. Reference OCA St. 8, p. 85.
- a. Can Mr. Colton guarantee that if the Company were to do “an exemplary job of achieving the outcomes [he] ha[s] identified” in his testimony, that he would not oppose the Company seeking an “upward adjustment” to its return on equity in the next base rate case?
 - b. To Mr. Colton’s knowledge, has the OCA ever supported an upward adjustment to a public utility’s return on equity due to exemplary management performance? If so, please identify the cases of which he is aware, including the case name, docket number, and order entry date.

RESPONSE DATE: January 12, 2026

RESPONDING WITNESS: Roger Colton

RESPONSE:

- a. No.
- b. Mr. Colton does not have knowledge of whether or not “OCA ever supported an upward adjustment to a public utility’s return on equity due to exemplary management performance.”

Colton: Appendix 2

Summary of Colton Pennsylvania Recommended Outcome Metrics

In order to fully understand many of the outcome metrics proposed in the dockets listed below, it is necessary to understand some of the specialized terminology. The following three terms, in particular, are defined by regulations of the Pennsylvania Public Utility Commission and are described by the PUC's Bureau of Consumer Services (BCS) in the BCS "Annual Report on Universal Service Programs and Collections Performance."¹⁷

- Customer Assistance Program (CAP): "*Customer assistance program*—A plan or program sponsored by a public utility for the purpose of providing universal service and energy conservation, as defined in 66 Pa.C.S. § 2202 or § 2803 (relating to definitions), in which customers make monthly payments based on household income and household size and under which customers shall comply with certain responsibilities and restrictions to remain eligible for the program."
- Confirmed Low-Income Customer: "A low-income customer is defined as one whose household income is at or below 150% of the federal poverty income guidelines (FPIG). A low-income customer is classified as confirmed low-income after their utility has obtained information that would reasonably place them within this FPIG level. Most confirmed low-income households are verified through the customer's receipt of a Low Income Home Energy Assistance Program (LIHEAP) grant, enrollment in a Universal Service program, or determined during the course of making a payment arrangement."
- Estimated Low-Income Customers: "The number of estimated low-income customers represents the public utility's approximation of its total (maximum) population of low-income customers in its service territory and is based on the latest census data available at the time of reporting. Census data is compiled by Pennsylvania State University annually and sent to the Commission for distribution to the EDCs and NGDCs for use in determining the estimated number of low-income customers."

¹⁷ Available at <https://www.puc.pa.gov/filing-resources/reports/universal-service-reports/>

Given this terminology, metrics recommended by Mr. Colton for measuring low-income outcomes performance by Pennsylvania utilities have included as follows:

1. Docket No. R-2022-3031211¹⁸ (Columbia Gas of Pennsylvania):

In this base rate case proceeding before the Pennsylvania Public Utility Commission (“PA PUC”) involving Columbia Gas, Mr. Colton proposed the following metrics by which to measure Columbia’s actions with respect to low-income customers, as well as credit and collection activities affecting low-income customers.

- The percentage of residential customers disconnected for nonpayment that are subsequently reconnected. (Of all PA natural gas distribution utilities, Columbia Gas has lowest percentage of disconnected customers reconnected.)
- Average residential arrears (in dollars) of customers in arrears.

In that same base rate case proceeding, Mr. Colton proposed the following outcome metrics specifically by which to measure Columbia’s performance with respect to its low-income customers. He distinguished between “activities” and “outcomes.” “Measuring “outcomes” is to be distinguished from measuring “activities” and measuring “outputs.” An “activity” is defined as the work performed that directly produces products or services. . .The “outcome” of a program is the accomplishment of program objectives attributable to program outputs.”

He then recommended the establishment of “goals” or “objectives” as the first step toward measuring outcomes. “The first step in measuring outcomes is to establish measurable objectives or goals (i.e., outcomes) that Columbia Gas should seek to achieve. Subsequent to establishing these measurable outcomes, Columbia Gas can engage in an ongoing process to determine whether those objectives have, in fact, been achieved and, if not, what needs to be modified in order to improve performance.” He thus recommended:

- **Outcome Objective #1:** Columbia Gas should achieve a Confirmed Low-Income identification rate, as a percentage of estimated low-income customers, for the utilities as a whole, no less than the Confirmed Low-Income identification rate of the top quartile of Pennsylvania natural gas utilities as a whole (excluding Columbia Gas).
- **Outcome Objective #2:** Columbia Gas should achieve a CAP participation rate, as a percentage of Confirmed Low-Income customers, no less than the CAP

¹⁸ Docket information available at <https://www.puc.pa.gov/docket/R-2022-3031211>

participation rate of the top quartile of Pennsylvania natural gas utilities as a whole (excluding Columbia Gas).

- **Outcome Objective #3:** Columbia Gas should achieve a CAP participation rate, as a percentage of its Confirmed Low-Income customers, in the lowest poverty level range that is no less than the proportion of households in that poverty level range for the Columbia Gas service territory as a whole.

Mr. Colton stated: “Through the first Outcome Objective, Columbia Gas will seek to ensure that it is adequately identifying its low-income customers. Through the second and third Outcome objectives, Columbia Gas will seek to ensure that, having identified its low-income population, it is then enrolling its known low-income customers into its primary low-income assistance program.”

2. Docket No. R-2022-3031172¹⁹ (Pennsylvania American Water Company):

In this base rate case proceeding before the PA PUC involving PAWC, Mr. Colton proposed the following metrics by which to measure PAWC’s actions with respect to credit and collection activities affecting low-income customers.

- The percentage of residential billings (in dollars) in debt compared to other Class A water utilities in Pennsylvania.
- The percentage of residential accounts in debt compared to other Class A water utilities in Pennsylvania.
- The percentage of residential customers in debt on payment arrangements compared to other Class A water utilities in Pennsylvania.
- PAWC’s percentage of gross residential write-offs compared to other Class A water utilities in Pennsylvania
- The percentage of Class A water utility shutoffs in Pennsylvania compared to the percentage of Class A water utility customers. (PAWC had nearly three-quarters of all Class A water utility shutoffs in Pennsylvania, despite having only somewhat over half of residential customers.)
- The degree to which the payment difficulties of residential accounts in arrears are resolved prior to nonpayment service disconnection. (While PAWC issues only

¹⁹ Docket information available at <https://www.puc.pa.gov/docket/R-2022-3031672>

55% of the state's water disconnection notices, it performs 73% of the state's water disconnections.)

- The rate of nonpayment disconnections per 100 customers. (PAWC disconnects its residential customers at a rate that is more than two times higher than the next highest water utility.

Using these metrics, Mr. Colton concluded with respect to PAWC's requested return on equity: "A water utility that has such poor collections performance, both in absolute terms and in terms relative to other Pennsylvania Class A water utilities, does not merit an equity enhancement for superior management performance."

3. **Docket No. R-2022-3031113²⁰ (PECO Energy (gas division)):**

In this base rate case proceeding before the PA PUC involving PECO Energy (gas), Mr. Colton proposed the following metrics by which to measure PECO's actions with respect to PECO's Customer Assistance Program (CAP) directed toward low-income customers.

- **Outcome Objective #1:** PECO Gas should achieve a Confirmed Low-Income identification rate, as a percentage of estimated low-income customers, no less than the Confirmed Low-Income identification rate of the top two Pennsylvania natural gas utilities (excluding PECO Gas).
- **Outcome Objective #2:** PECO Gas should achieve a CAP participation rate, as a percentage of Confirmed Low-Income customers, no less than the CAP participation rate of the top two Pennsylvania natural gas utilities (excluding PECO Gas).
- **Outcome Objective #3:** PECO Gas should achieve a CAP default rate as a percentage of participants in the lowest poverty level range that is no less than the CAP default rate in that poverty level range for the top two Pennsylvania gas utilities (excluding PECO Gas).

Mr. Colton stated: "Through the first Outcome objective, PECO Gas will seek to ensure that it is adequately identifying its low-income customers. Through the second and third Outcome objectives, PECO Gas will seek to ensure that, having identified its low-income population, it is then enrolling its known low-income customers into its primary low-income assistance program and maintaining that participation."

²⁰ Docket information available at <https://www.puc.pa.gov/docket/R-2022-3031113>

4. Docket No.R-2021-3030218²¹ (UGI Utilities (gas)):

In this base rate proceeding before the PA PUC involving UGI Utilities (gas), Mr. Colton proposed the following metrics by which to measure UGI (gas) actions with respect to low-income customers, as well as credit and collection activities affecting low-income customers.

- The percentage of Confirmed Low-Income customers in debt relative to statewide average of Pennsylvania natural gas distribution utilities and relative to individual performance of other natural gas distribution utilities.
- The percentage of billings (in dollars) in debt for Confirmed Low-Income customers relative to statewide average of Pennsylvania natural gas distribution utilities and relative to individual performance of other natural gas distribution utilities.
- Collections performance achieved through its universal service programs taking into account the total residential collection costs relative to other Pennsylvania natural gas distribution utilities (e.g., despite poor collection results, UGI Gas collection expenditures are higher than the next highest utility). In addition to spending more on total residential collections, UGI spends a higher percentage of its residential collection costs on its Confirmed Low-Income customers, a percentage which is 50% higher than the statewide average percentage of total collection costs devoted to Confirmed Low-Income customers, and far higher than the utility that has the next highest percentage.
- The percentage of its Confirmed Low-Income customers enrolled in CAP relative to statewide average and relative to enrollment figures of other Pennsylvania natural gas distribution utilities. (The UGI Gas percentage of CAP enrollees of Confirmed Low-Income customers is roughly half that of the Pennsylvania natural gas utilities statewide and noticeably lower than the gas utility with the next highest percentage.)

Then, specifically with respect to UGI's CAP (gas), Mr. Colton recommended:

- **Outcome Objective #1:** UGI Gas should achieve a Confirmed Low-Income identification rate, as a percentage of estimated low-income customers, no less than the Confirmed Low-Income identification rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

²¹ Docket information available at <https://www.puc.pa.gov/docket/R-2021-3030218>

- **Outcome Objective #2:** UGI Gas should achieve a CAP participation rate, as a percentage of Confirmed Low-Income customers, no less than the CAP participation rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).
- **Outcome Objective #3:** UGI Gas should achieve a CAP default rate as a percentage of participants in the lowest poverty level range that is no less than the CAP default rate in that poverty level range for Pennsylvania gas utilities as a whole.

Mr. Colton stated: “Through the first Outcome objective, UGI Gas will seek to ensure that it is adequately identifying its low-income customers. Through the second and third Outcome objectives, UGI Gas will seek to ensure that, having identified its low-income population, it is then enrolling its known low-income customers into its primary low-income assistance program.”

**5. Docket No. M-2016-2542415 and Docket No. P-2020-3018867 (consolidated)²²
(Philadelphia Gas Works, PGW):**

In this periodic review of PGW’s Universal Service and Energy Conservation Plan (USECP) by the PA PUC, Mr. Colton proposed the following outcome metrics by which to measure the performance of PGW’s CAP (called its Customer Responsibility Program, or CRP).

- PGW’s program objective should be to achieve a CRP participation rate of no less than 40% of its estimated low-income population.
- As a means of measuring an improvement in the ability of PGW CRP participants to pay their bills, PGW should be directed to adopt the following outcome objectives:
 - 1) The “percentage of CAP dollars paid” of CRP participants should place PGW’s performance in the top quartile of Pennsylvania natural gas utilities. According to BCS, “the percentage of CAP bills paid by CAP customers is calculated by dividing the total annual CAP payments (\$) by the total annual CAP amount billed (\$).”
 - 2) The “CAP payment rate” of CRP participants should place PGW’s performance in the top quartile of Pennsylvania natural gas utilities. According to BCS, “the CAP payment rate is calculated by dividing the

²² Docket information available at <https://www.puc.pa.gov/docket/M-2016-2542415>

total number of full monthly CAP payments by the total number of monthly CAP bills rendered. The CAP payment rate reflects overall program totals and is not a household average or broken out by poverty level.”

- 3) The percentage of CRP participants with in-program arrears should not exceed the percentage of residential customers with arrears.
- As a means of measuring the extent to which it is providing its CRP participants a fresh start regarding arrears that have accrued on their accounts during the time before they begin to receive an affordable bill, PGW should adopt the following outcome objective: arrearages eligible for forgiveness in each year (in dollars) should be actually forgiven at a rate that equals or approaches 100%.

6. Docket No. R-2021-3027385²³ (Aqua PA):

In this base rate proceeding before the PA PUC involving Aqua PA, Mr. Colton proposed the following metrics by which to measure management effectiveness with respect to credit and collection activities affecting low-income customers.

- The percentage of residential customers in debt relative to other Pennsylvania water utilities.
- The average dollars of arrears for active residential customers relative to other Class A Pennsylvania water utilities.
- The direction of the Bills Behind statistic for Aqua PA over a seven year period should not degrade.
- The direction of the average annual dollars of arrears for active residential customers over seven years should not degrade.
- The direction of the rate of residential nonpayment disconnections per 100 residential customers over seven years should not degrade.

In addition, Mr. Colton proposed that the effectiveness of Aqua PA actions responding to low-income needs should be measured by the following metrics relating to: (1) the completeness of payment, (2) the timeliness of payments, and (3) the regularity of payments. More specifically, the metrics proposed to measure completeness, timeliness, and regularity of payments, included:

²³ Docket information available at <https://www.puc.pa.gov/docket/R-2021-3027385>

- The rate at which disconnect notices were issued to low-income customers (“rate” being the number of disconnect notices per 100 bills rendered) compared to the rate which disconnect notices were issued to residential customers as a whole.
- The rate at which low-income customers were subject to nonpayment disconnections compared to the rate at which residential customers as a whole were subject to nonpayment disconnections (“rate” being ratio of disconnect notices to actual nonpayment disconnections).
- The payment regularity ratio (calculated by placing the number of payments in the numerator and the number of bills in the denominator). The metric measured for every 100 residential monthly bills rendered, how many payments were received. Performance for low-income customers was compared to performance for residential customers as a whole.
- The average monthly arrears (of accounts in arrears) for identified low-income customers compared to the average monthly arrears (of accounts in arrears) for residential customers as a whole.
- The degree to which bill payment was untimely, as measured by Bills Behind, for identified low-income customers compared to the Bills Behind for residential customers as a whole.
- The percentage of identified low-income customers in arrears compared to the percentage of residential customers as a whole in arrears;
- The average arrearage balance at the time of a nonpayment service disconnection for identified low-income customers (measured by Bills Behind) compared to the average arrearage balance at the time of a nonpayment service disconnection for residential customers as a whole (measured by Bills Behind).
- (Data on payment arrangements, and the success or lack thereof, was not tracked by Aqua PA and thus no outcome metric was proposed.)

7. Docket No. R-2021-3024750²⁴ (Duquesne Light Company):

²⁴ Docket information available at <https://www.puc.pa.gov/docket/R-2021-3024750>

In this base rate proceeding before the PA PUC involving Duquesne Light Company, Mr. Colton proposed the following metrics by which to measure how well Duquesne Light responds to the needs of its low-income customers:

- The percentage of estimated low-income customers that are identified as Confirmed Low-Income customers for Duquesne Light relative to the percentage identified as Confirmed Low-Income customers by all Pennsylvania electric distribution utilities (number of Confirmed Low-Income customers in numerator; number of estimated low-income customers in denominator).
- The percentage of Confirmed Low-Income customers in debt that are (are not) on deferred payment arrangements compared to the percentage of Confirmed Low-Income customers in debt that are (are not) on deferred payment arrangements for all Pennsylvania electric distribution utilities.
- The rate of residential nonpayment disconnections (number per 100 customers) as compared to the rate of residential nonpayment disconnections for all Pennsylvania electric distribution utilities. Supplemental: consider the rate of nonpayment disconnections taking into account the rate at which residential customers are in arrears (i.e., Duquesne had one of highest termination rates in the state despite having the second lowest percentage of residential customers in arrears.)

8. Docket No. R-2021-3024601²⁵ (PECO Energy (electric division)):

In this base rate proceeding before the PA PUC involving PECO Energy (electric), Mr. Colton proposed that the following metrics be employed to examine PECO's responsiveness to the needs of its low-income customers.

- The percentage of estimated low-income customers identified as Confirmed Low-Income customers compared to Pennsylvania's other electric distribution utilities.
- The ratio of the number of deferred payment arrangements to the number of nonpayment disconnections compared to that ratio for Pennsylvania's other electric distribution utilities.
- The direction, over time, of the ratio of the number of deferred payment arrangements to the number of nonpayment disconnections (e.g., "while in 2016, PECO performed 1.17 disconnections for every payment agreement it entered into, by 2019, that ratio had increased to 1.46 (an increase of 25%.")

²⁵ Docket information available at <https://www.puc.pa.gov/docket/R-2021-3024601>

- The percentage of residential billings in debt that are subject to a deferred payment agreement, relative to that percentage for Pennsylvania's other electric distribution utilities (i.e., "the percentage of PECO residential dollars in debt but not on agreement was higher than every other Pennsylvania electric utility. The next highest utility was PPL, full ten percent better than PECO.")
- The rate of residential deferred payment agreements resulting in a default compared to Pennsylvania's other electric distribution utilities (i.e., "PECO has a rate of. . .customers who failed to maintain one or more payment arrangement that is far higher than any other Pennsylvania electric utility.")
 - Proposing to measure "the ratio of the number of residential customers who 'fail to maintain' a payment arrangement to the number of residential customers who entered into a payment arrangement. The ratio of customers who "fail to maintain" their payment arrangements is two times higher for PECO than it is for the next highest utility."

WITNESS: Lisa Norden

PPL Electric Utilities Corporation
Response to the Set XXV Data Requests of the
Office of Consumer Advocate (OCA)
Dated December 4, 2025
Docket No. R-2025-3057164

OCA XXV-18	According to Ms. Norden, at page 9, line 14 of her testimony, the annual expense of the Company's proposal to include transaction fees in base rates is \$4.98 million. Please explain the difference between the \$4.98 million and the \$5.2 million transaction fees identified in the response to I&E-RE-I-12-D (C).
PPL Electric Response	Refer to I&E-RE-II-19 Tab(B) The fees used for the analysis were for the twelve months ending June 2025 (July 2024 through June 2025), which totaled approximately \$4 million. PPL Electric used the above-referenced number and the 30% increase anticipated in the elimination of the fee to arrive at the \$5.2 million included in the FPFTY. To clarify, the expense amount included in the FPFTY is approximately \$5.2 million. The \$4.98 million referenced in Ms. Norden's direct testimony was based on PPL Electric's original analysis around payment transactions fees was completed using the period November 2023 through October 2024 and resulted in approximately \$4.98 million. Further revision to that analysis using data for the twelve months ending June 2025 resulted in the \$5.2 million used in the FPFTY.

PA PUC Docket No. R-2025-3057164

Question:
PPL-EJA-II-6

Date of Response:
01/09/2026

Response Provided By:
Karl R. Rábago

Question

Reference EJA St. No.1, p. 17. Please explain in detail why Mr. Rábago believes that the Company's proposal to recover Universal Service and Energy Conservation Plan ("USECP") employee salaries and wages through the Universal Service Rider ("USR") would "dilute[]" the "USR funds available."

Answer

Mr. Rábago's testimony on the issue should be read as a whole. *See* EJA St. No. 1, p. 15-18. If the fund pays for new costs and the fund budget is not increased, the funds available for other program spending would be reduced.

WITNESS: Lisa Norden

**PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania
(CAUSE-PA)
Dated October 16, 2025
Docket No. R-2025-3057164**

CAUSE-PA I-20 For each month from July 1, 2023, to date, please provide:

- a) Mean and Median usage for residential customers separated by rate class (heating vs non-heating);
- b) Mean and Median usage for Confirmed Low Income Customers, separated by rate class;
- c) Mean and Median usage for CAP customers, separated by rate class;
- d) Mean and Median usage for Confirmed Low Income customers not enrolled in CAP separated by rate class.

Please provide this data in a live Excel spreadsheet.

PPL Electric Response See CAUSE-PA I-20 Attachment 1.

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CAUSE-PA 1-20: a) Mean and Median usage for residential customers separated by rate class (heating vs non-heating)

year_mo	heat_type	cust_count	mean_usage	median_usage
2023-07	ELECTRIC	506,876	868.84	753.00
2023-07	NON-ELECTRIC	795,970	839.51	714.00
2023-08	ELECTRIC	509,022	921.37	813.00
2023-08	NON-ELECTRIC	796,921	928.57	812.00
2023-09	ELECTRIC	508,252	872.29	764.00
2023-09	NON-ELECTRIC	794,669	860.16	744.00
2023-10	ELECTRIC	508,960	740.54	653.00
2023-10	NON-ELECTRIC	794,420	651.31	550.00
2023-11	ELECTRIC	508,806	863.24	766.00
2023-11	NON-ELECTRIC	792,896	608.00	503.00
2023-12	ELECTRIC	508,953	1,426.53	1,259.00
2023-12	NON-ELECTRIC	791,597	802.69	624.00
2024-01	ELECTRIC	509,534	1,770.65	1,562.00
2024-01	NON-ELECTRIC	790,949	926.08	707.00
2024-02	ELECTRIC	509,645	1,613.77	1,419.00
2024-02	NON-ELECTRIC	790,036	790.14	585.00
2024-03	ELECTRIC	511,180	1,390.11	1,211.00
2024-03	NON-ELECTRIC	791,020	733.68	558.00
2024-04	ELECTRIC	514,151	1,153.79	1,012.00
2024-04	NON-ELECTRIC	792,844	677.06	534.00
2024-05	ELECTRIC	514,706	797.63	711.00
2024-05	NON-ELECTRIC	792,763	598.47	500.00
2024-06	ELECTRIC	515,299	802.82	705.00
2024-06	NON-ELECTRIC	792,183	743.32	630.00
2024-07	ELECTRIC	517,012	987.96	875.00
2024-07	NON-ELECTRIC	792,757	1,014.54	890.00
2024-08	ELECTRIC	517,403	954.06	846.00
2024-08	NON-ELECTRIC	791,854	980.55	861.00

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2024-09	ELECTRIC	517,084	820.14	718.00
2024-09	NON-ELECTRIC	790,646	796.74	683.00
2024-10	ELECTRIC	517,703	698.54	616.00
2024-10	NON-ELECTRIC	790,039	620.79	525.00
2024-11	ELECTRIC	517,591	794.90	708.00
2024-11	NON-ELECTRIC	788,397	586.25	486.00
2024-12	ELECTRIC	518,642	1,412.20	1,216.00
2024-12	NON-ELECTRIC	788,180	796.68	616.00
2025-01	ELECTRIC	518,962	1,982.21	1,743.00
2025-01	NON-ELECTRIC	786,649	963.85	711.00
2025-02	ELECTRIC	519,606	2,075.85	1,831.00
2025-02	NON-ELECTRIC	786,047	944.88	667.00
2025-03	ELECTRIC	521,548	1,512.65	1,295.00
2025-03	NON-ELECTRIC	786,793	756.30	553.00
2025-04	ELECTRIC	523,300	1,064.78	932.00
2025-04	NON-ELECTRIC	787,613	642.71	507.00
2025-05	ELECTRIC	525,159	799.94	702.00
2025-05	NON-ELECTRIC	788,004	604.99	501.00
2025-06	ELECTRIC	525,973	766.53	674.00
2025-06	NON-ELECTRIC	787,784	669.58	562.00
2025-07	ELECTRIC	526,393	975.14	862.00
2025-07	NON-ELECTRIC	787,119	997.27	875.00
2025-08	ELECTRIC	527,622	951.29	842.00
2025-08	NON-ELECTRIC	786,779	984.63	867.00
2025-09	ELECTRIC	527,241	787.96	684.00
2025-09	NON-ELECTRIC	785,378	763.26	649.00

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CAUSE-PA 1-20: b) Mean and Median usage for Confirmed Low Income Customers, separated by rate class

year_mo	heat_type	cust_count	mean_usage	median_usage
2023-07	ELECTRIC	101,554	937.86	816.00
2023-07	NON-ELEC	131,310	943.38	826.00
2023-08	ELECTRIC	101,051	985.70	869.00
2023-08	NON-ELEC	131,607	1,033.70	921.00
2023-09	ELECTRIC	100,740	930.88	821.00
2023-09	NON-ELEC	131,938	955.76	848.00
2023-10	ELECTRIC	101,263	829.74	733.00
2023-10	NON-ELEC	132,790	750.82	655.00
2023-11	ELECTRIC	101,618	1,027.15	898.00
2023-11	NON-ELEC	133,174	746.20	629.00
2023-12	ELECTRIC	102,706	1,730.45	1,512.00
2023-12	NON-ELEC	133,839	1,027.51	806.00
2024-01	ELECTRIC	104,572	2,127.68	1,865.00
2024-01	NON-ELEC	135,029	1,184.25	911.00
2024-02	ELECTRIC	105,720	1,954.29	1,716.00
2024-02	NON-ELEC	135,830	1,034.10	774.00
2024-03	ELECTRIC	106,879	1,700.84	1,473.00
2024-03	NON-ELEC	136,634	957.09	733.00
2024-04	ELECTRIC	108,112	1,405.80	1,220.00
2024-04	NON-ELEC	137,527	863.37	688.00
2024-05	ELECTRIC	107,435	930.95	823.00
2024-05	NON-ELEC	136,931	714.71	617.00
2024-06	ELECTRIC	106,917	879.77	780.00
2024-06	NON-ELEC	136,458	838.99	740.00
2024-07	ELECTRIC	106,893	1,059.41	939.00
2024-07	NON-ELEC	136,775	1,122.30	1,007.00
2024-08	ELECTRIC	106,367	1,032.12	916.00
2024-08	NON-ELEC	136,689	1,100.77	986.00

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2024-09	ELECTRIC	106,429	893.31	790.00
2024-09	NON-ELEC	136,967	902.92	801.00
2024-10	ELECTRIC	105,979	787.51	700.00
2024-10	NON-ELEC	136,890	719.00	632.00
2024-11	ELECTRIC	105,550	947.07	833.00
2024-11	NON-ELEC	136,427	721.84	616.00
2024-12	ELECTRIC	106,691	1,710.66	1,466.00
2024-12	NON-ELEC	136,757	1,023.85	802.00
2025-01	ELECTRIC	108,747	2,368.69	2,085.00
2025-01	NON-ELEC	137,541	1,251.27	937.00
2025-02	ELECTRIC	111,159	2,483.83	2,205.00
2025-02	NON-ELEC	138,691	1,250.16	907.00
2025-03	ELECTRIC	113,421	1,834.20	1,578.00
2025-03	NON-ELEC	140,087	997.30	743.00
2025-04	ELECTRIC	114,294	1,296.09	1,127.00
2025-04	NON-ELEC	140,552	820.72	660.00
2025-05	ELECTRIC	113,867	934.98	820.00
2025-05	NON-ELEC	139,948	725.46	621.00
2025-06	ELECTRIC	113,258	857.14	758.00
2025-06	NON-ELEC	139,425	768.49	672.00
2025-07	ELECTRIC	113,096	1,058.08	936.00
2025-07	NON-ELEC	139,528	1,117.72	1,000.00
2025-08	ELECTRIC	113,246	1,036.17	917.00
2025-08	NON-ELEC	139,960	1,110.43	995.00
2025-09	ELECTRIC	113,530	867.07	761.00
2025-09	NON-ELEC	140,302	869.60	765.00

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CAUSE-PA 1-20: c) Mean and Median usage for CAP customers, separated by rate class

year_mo	heat_type	cust_count	mean_usage	median_usage
2023-07	ELECTRIC	33,967	941.88	828.00
2023-07	NON-ELEC	34,930	960.49	852.00
2023-08	ELECTRIC	34,297	987.82	876.00
2023-08	NON-ELEC	35,923	1,051.81	946.00
2023-09	ELECTRIC	34,604	930.05	826.00
2023-09	NON-ELEC	37,051	965.63	871.00
2023-10	ELECTRIC	35,383	876.97	771.00
2023-10	NON-ELEC	38,516	790.72	698.00
2023-11	ELECTRIC	35,693	1,130.67	979.00
2023-11	NON-ELEC	39,343	800.43	679.00
2023-12	ELECTRIC	35,864	1,925.95	1,690.00
2023-12	NON-ELEC	39,624	1,105.11	869.00
2024-01	ELECTRIC	36,352	2,365.86	2,081.00
2024-01	NON-ELEC	39,873	1,266.33	977.00
2024-02	ELECTRIC	36,448	2,174.07	1,931.00
2024-02	NON-ELEC	39,734	1,111.37	840.00
2024-03	ELECTRIC	36,509	1,900.63	1,666.00
2024-03	NON-ELEC	39,501	1,033.75	796.00
2024-04	ELECTRIC	36,804	1,583.35	1,384.00
2024-04	NON-ELEC	39,631	936.00	752.00
2024-05	ELECTRIC	36,966	1,017.28	901.00
2024-05	NON-ELEC	39,792	764.83	669.00
2024-06	ELECTRIC	37,021	906.71	805.00
2024-06	NON-ELEC	40,011	872.18	783.00
2024-07	ELECTRIC	36,961	1,059.90	942.00
2024-07	NON-ELEC	40,394	1,144.30	1,036.50
2024-08	ELECTRIC	36,255	1,022.26	909.00
2024-08	NON-ELEC	39,891	1,111.41	1,007.00

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2024-09	ELECTRIC	35,243	894.84	791.00
2024-09	NON-ELEC	38,619	917.59	826.00
2024-10	ELECTRIC	34,375	807.36	717.00
2024-10	NON-ELEC	37,494	743.15	662.00
2024-11	ELECTRIC	33,705	1,029.25	904.00
2024-11	NON-ELEC	36,590	765.64	656.00
2024-12	ELECTRIC	32,103	1,893.02	1,629.00
2024-12	NON-ELEC	33,699	1,085.65	850.00
2025-01	ELECTRIC	31,702	2,612.99	2,317.00
2025-01	NON-ELEC	32,679	1,315.00	993.00
2025-02	ELECTRIC	32,464	2,752.22	2,475.00
2025-02	NON-ELEC	33,089	1,318.18	968.00
2025-03	ELECTRIC	33,357	2,057.20	1,797.00
2025-03	NON-ELEC	33,711	1,063.60	800.00
2025-04	ELECTRIC	34,466	1,462.31	1,281.00
2025-04	NON-ELEC	34,485	881.12	712.00
2025-05	ELECTRIC	34,976	1,017.60	892.00
2025-05	NON-ELEC	34,928	766.59	660.00
2025-06	ELECTRIC	35,290	894.92	792.00
2025-06	NON-ELEC	35,340	795.89	705.00
2025-07	ELECTRIC	35,419	1,053.78	933.00
2025-07	NON-ELEC	35,737	1,125.24	1,017.00
2025-08	ELECTRIC	35,694	1,028.16	913.00
2025-08	NON-ELEC	36,174	1,116.30	1,007.00
2025-09	ELECTRIC	35,808	875.05	772.00
2025-09	NON-ELEC	36,619	884.69	788.00

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CAUSE-PA I-20d Attachment 1

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CAUSE-PA 1-20: d) Mean and Median usage for Confirmed Low Income customers not enrolled in CAP separated by rate class

year_mo	heat_type	cust_count	mean_usage	median_usage
2023-07	ELECTRIC	67,587	935.85	809.00
2023-07	NON-ELEC	96,380	937.17	816.00
2023-08	ELECTRIC	66,754	984.61	866.00
2023-08	NON-ELEC	95,684	1,026.91	911.00
2023-09	ELECTRIC	66,136	931.31	817.00
2023-09	NON-ELEC	94,887	951.91	838.00
2023-10	ELECTRIC	65,880	804.37	711.00
2023-10	NON-ELEC	94,274	734.52	637.00
2023-11	ELECTRIC	65,925	971.11	852.00
2023-11	NON-ELEC	93,831	723.45	609.00
2023-12	ELECTRIC	66,842	1,625.55	1,421.00
2023-12	NON-ELEC	94,215	994.88	782.00
2024-01	ELECTRIC	68,220	2,000.76	1,753.00
2024-01	NON-ELEC	95,156	1,149.86	885.00
2024-02	ELECTRIC	69,272	1,838.66	1,609.00
2024-02	NON-ELEC	96,096	1,002.15	749.00
2024-03	ELECTRIC	70,370	1,597.19	1,384.00
2024-03	NON-ELEC	97,133	925.91	708.00
2024-04	ELECTRIC	71,308	1,314.16	1,142.00
2024-04	NON-ELEC	97,896	833.97	666.00
2024-05	ELECTRIC	70,469	885.66	784.00
2024-05	NON-ELEC	97,139	694.18	596.00
2024-06	ELECTRIC	69,896	865.50	766.00
2024-06	NON-ELEC	96,447	825.23	722.00
2024-07	ELECTRIC	69,932	1,059.15	937.00
2024-07	NON-ELEC	96,381	1,113.08	994.00
2024-08	ELECTRIC	70,112	1,037.21	920.00
2024-08	NON-ELEC	96,798	1,096.39	977.00

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2024-09	ELECTRIC	71,186	892.56	789.00
2024-09	NON-ELEC	98,348	897.16	790.00
2024-10	ELECTRIC	71,604	777.98	690.00
2024-10	NON-ELEC	99,396	709.89	620.00
2024-11	ELECTRIC	71,845	908.51	800.00
2024-11	NON-ELEC	99,837	705.79	601.00
2024-12	ELECTRIC	74,588	1,632.18	1,399.00
2024-12	NON-ELEC	103,058	1,003.64	787.00
2025-01	ELECTRIC	77,045	2,268.16	1,995.00
2025-01	NON-ELEC	104,862	1,231.41	921.00
2025-02	ELECTRIC	78,695	2,373.11	2,100.00
2025-02	NON-ELEC	105,602	1,228.85	888.00
2025-03	ELECTRIC	80,064	1,741.29	1,491.00
2025-03	NON-ELEC	106,376	976.30	726.00
2025-04	ELECTRIC	79,828	1,224.32	1,064.00
2025-04	NON-ELEC	106,067	801.09	643.00
2025-05	ELECTRIC	78,891	898.35	789.00
2025-05	NON-ELEC	105,020	711.78	608.00
2025-06	ELECTRIC	77,968	840.04	741.00
2025-06	NON-ELEC	104,085	759.19	661.00
2025-07	ELECTRIC	77,677	1,060.04	938.00
2025-07	NON-ELEC	103,791	1,115.13	994.00
2025-08	ELECTRIC	77,552	1,039.86	919.00
2025-08	NON-ELEC	103,786	1,108.38	991.00
2025-09	ELECTRIC	77,722	863.39	757.00
2025-09	NON-ELEC	103,683	864.27	757.00

**Response of the Retail Energy Supply Association (“RESA”)
to the Interrogatories of PPL Electric Utilities Corporation (“PPL”), Set II
in Docket No. R-2025-3057164**

Request: PPL-II-3 Reference RESA Statement No. 1, p. 26. Mr. Lacey states that “[r]ejecting this change does not require an adjustment to base rates.” Please explain in detail how Mr. Lacey concluded that no *pro forma* adjustment would be required to put these costs back into base distribution rates if the Company’s proposal were rejected, when the Company’s base rate case filing took the costs out of base distribution rates due to those costs being directly to Electric Generation Suppliers (“EGSs”). Please also provide all documents, workpapers, calculations, and analyses relied upon in reaching that conclusion and in responding to this discovery request.

Response: This interrogatory request includes the answer in its own question. PPL states in this request that “the Company’s base rate case filing took the costs out of base distribution rates...” This was exactly the point of Mr. Lacey’s testimony. It is PPL’s proposal that requires an adjustment to base rates. If the Commission rejects this proposal, requiring PPL to continue the status quo, there is no adjustment to base rates. PPL is proposing a change that is wholly unsupported by any testimony. PPL has offered no facts, policy argument or common business practice that would justify having EGSs subsidize the market operations function that the utility is required to perform. PPL’s market operations benefit all customers in the service territory, not just shopping customers. As explained in Mr. Lacey’s testimony on page 26, PPL’s rates have included EDI and DUNs costs since the advent of retail choice. Therefore, continuing that method of cost recovery maintains the long-standing status quo of recovering them in rates and no adjustment to base rates is required. Rejecting this change does not require an adjustment to base rates.

Response provided by: Frank Lacey, Consultant for Retail Energy Supply Association
Dated: January 15, 2026

WITNESS: Lisa Norden

PPL Electric Utilities Corporation
Response to the Set I Data Requests of the
Retail Energy Supply Association (RESA)
Dated November 14, 2025
Docket No. R-2025-3057164

RESA I-23

Reference PPL St. No. 18, p. 17, lines 13-14.
Explain in detail how assessing EGS EDI charges will
“encourage EGS to more efficiently use company resources.”
Provide (on an anonymized basis) any examples, with
supporting documentation, of specific instances where PPL
determined an EGS was not “efficiently” using company
resources. Please explain how assessing EDI charges in these
specific examples would have resulted in a more efficient use of
company resources.

PPL Electric
Response

By assigning costs directly to EGSs based on their transaction
volume, PPL Electric:

- Creates Cost Accountability: EGSs that generate excessive or redundant transactions will bear the cost, thereby incentivizing them to streamline processes.
- Promotes System Efficiency: EGSs will reduce duplicate requests and improve data quality to avoid costly rejections.
- Aligns Costs: Instead of allocating costs across all ratepayers, charges are allocated to entities driving the expense.

Examples of Inefficient EGS Use of Resources

- High Volume of Rejected Transactions
 - EGSs failing to follow EDI standards often submit incorrect data, leading to multiple retries.
- Unnecessary Account Maintenance
 - Certain suppliers send frequent non-critical updates (name changes, address corrections) creating high volume transactions.

How charges would improve efficiency:

- Enrollment errors: If the EGS bears the cost of each failed enrollment, they can invest in better validation tools to reduce the number of entries.

WITNESS: Lisa Norden

- Rejected transactions: Financial impact motivates EGSs to comply with EDI standards, which should reduce error rates and manual intervention.

If EDI charges were assessed:

- EGSs would have financial incentives to eliminate unused DUNS numbers and consolidate identifiers.
- Charges for the set-up would discourage suppliers from creating redundant identifiers without operational need.
- Overall transaction costs would decrease.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
DANIEL JOHNSON
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: IT Upgrades

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Daniel Johnson. My business address is 280 Melrose Street, Providence, Rhode
4 Island 02907.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am Senior Vice President, Chief Information Officer for PPL Services Corporation (“PPL
8 Services”), a subsidiary of PPL Corporation and an affiliate of PPL Electric
9 Utilities Corporation (“PPL Electric” or the “Company”).

10
11 **Q. Have you previously filed testimony in this matter?**

12 A. Yes. I previously submitted direct testimony on behalf of the Company, PPL Electric
13 Statement No. 19.

14
15 **Q. What is the purpose of your rebuttal testimony?**

16 A. The purpose of my rebuttal testimony is to respond to the recommendations of Retail Energy
17 Supply Association (“RESA”) Witness Lacey. Specifically, I address testimony regarding
18 the recommendation to update PPL Electric’s Information Technology (“IT”) systems to
19 create an online portal where suppliers can access real-time data and self-serve. I also address
20 Mr. Lacey’s request to provide direct updates to suppliers and commission staff during any
21 IT upgrade.

22

1 **Q. Have you prepared any exhibits or schedules in support of your rebuttal testimony?**

2 A. No.

3
4 **II. IT UPGRADES**

5 **Q. What are RESA Witness Lacey's concerns with respect to the Company's proposed IT**
6 **upgrades?**

7 A. Mr. Lacey claims that the Company's upgrade of its IT infrastructure will impact operations
8 between suppliers and the Company, and that these impacts could be negative "if not managed
9 properly prior to implementation." (RESA St. No. 1, p. 5.) He further expresses concern that
10 while it may not be the Company's intent to allow its IT upgrades to have a direct impact on
11 supplier operations or shopping customers, it is the experience of multiple RESA members
12 that significant IT upgrades have major impacts on supplier operations and shopping
13 customers. (RESA St. No. 1, p. 12.)

14
15 **Q. Does Mr. Lacey make any recommendations with respect to the Company's proposed**
16 **IT upgrades?**

17 A. Yes. He recommends that the Commission direct the Company to "update its data
18 management systems to create an online portal where suppliers can access real-time data and
19 'self-serve' and find out at any point in time, the status of their accounts, if they are active or
20 inactive, dates of service, low income flags, move transactions, reinstatement transactions,
21 bill cycle calendar information, commercial meter flags, customer mailing address changes
22 and any other information relative to EDC/EGS shared customers." (RESA St. No. 1, p. 4.)

1
2 **Q. Do you agree with this recommendation?**

3 A. No. The Company has not proposed any functional changes to its current portal, and electric
4 generation suppliers (“EGSs”) have not provided any evidence in this proceeding that the
5 current systems are inadequate. Further, these requests would be intrusive and overly onerous
6 for the Company to comply with. Also, Mr. Lacey’s assumption that PPL Electric’s IT
7 upgrades have not begun is inaccurate. The project began planning and design at the
8 beginning of 2025. Significant rework would be required to accommodate the addition of the
9 requested new system, putting an undue cost burden on all customers to the sole benefit of
10 EGSs.

11
12 **Q. Does Mr. Lacey make any further recommendations with respect to the Company’s**
13 **proposed IT upgrades?**

14 A. Yes. He recommends that the Commission direct the Company to “provide daily updates to
15 competitive suppliers and weekly updates to Commission staff for at least the first 90 days of
16 any system upgrade/transition, including reporting on the number of issues identified by
17 suppliers, the estimated number of customers impacted, an explanation of PPL's effort to
18 resolve those issues without placing undue burden on suppliers, and an estimated timeline for
19 resolution.” (RESA St. No. 1, p. 15.)

20

1 **Q. Should this recommendation be adopted?**

2 A. No. As Mr. Lacey indicates, the Commission did not approve a similar request by RESA in
3 PECO Energy Company's Default Service Plan ("DSP") VI proceeding. Although Mr. Lacey
4 believes that the Commission should reach a different result here, his proposal would result
5 in EGSs micromanaging the daily operations of the Company, which is unwarranted and
6 unduly burdensome and presupposes a problem and lack of communication.

7
8 **Q. Is there another recommendation that Mr. Lacey makes with respect to the Company's**
9 **proposed IT upgrades?**

10 A. Yes. He proposes that the Commission direct the Company to "assign each supplier operating
11 in the market a consistent point of contact for addressing any customer system information
12 upgrade issues experienced by that supplier." (RESA St. No. 1, p. 15.)

13
14 **Q. Please respond to this recommendation.**

15 A. The Company already has an established Supplier Services team, which will remain the point
16 of contact throughout the IT upgrade implementations. No change is needed from the
17 Company's current practices regarding communication and having a point of contact for
18 suppliers with respect to proposed IT upgrades.

19
20 **Q. Does Mr. Lacey make any other proposals with respect to the Company's proposed IT**
21 **upgrades?**

1 A. Yes. He recommends that the Commission direct the Company to “exercise flexibility
2 regarding troubleshooting supplier-specific issues with the ultimate goal of offering realistic
3 workarounds and solutions that do not place unnecessary burdens on the supplier. (RESA
4 Statement No. 1, p. 15.)

5
6 **Q. Would you please respond to that recommendation?**

7 A. The Company consistently strives to identify and implement solutions that minimize impact
8 and avoid placing unnecessary burdens on our stakeholders, suppliers, or customers. This
9 approach reflects PPL Electric’s commitment to collaboration, efficiency, and fairness in all
10 aspects of the Company’s operations.

11
12 **Q. Does Mr. Lacey allege that there may be challenges in implementing the Company’s IT**
13 **upgrades?**

14 A. Yes. He contends that there is a possibility of challenges arising in the implementation of the
15 Company’s IT upgrades that may frustrate or inconvenience customers’ shopping abilities,
16 ability to pay or receive bills, and interact with EGSs. (RESA St. No. 1, p. 15.) He further
17 notes that it is “unreasonable” to place customers in this position, and that negative impacts
18 could leave consumers with negative impressions of suppliers. (*Id.*)

19
20 **Q. Please respond to these claims.**

21 A. Although I agree, in part, with Mr. Lacey’s premise that it is important to provide adequate
22 support during the Company’s IT upgrades, I do not agree that the planned IT upgrades will

1 result in an “unreasonable” position for customers. The Company has planned for significant
2 support to respond to and resolve any issues stemming from the implementation in a timely
3 manner.

4
5 **Q. What is Mr. Lacey’s final recommendation with respect to the Company’s proposed IT**
6 **upgrades?**

7 A. Mr. Lacey proposes that the Commission direct the Company to “include systems that support
8 retail choice as part of its infrastructure modernization and upgrade process.” (RESA St. No.
9 1, p. 17.)

10
11 **Q. Do you believe this recommendation should be adopted?**

12 A. No. The Customer Information System (“CIS”) is foundational to facilitating all customer
13 interactions, including retail choice. Modernizing and upgrading that system will introduce
14 changes and new capabilities not currently supported in existing systems. The Company will
15 be working directly with suppliers to implement and test these changes before they go-live.
16 In addition to CIS, as part of the Company’s normal planning processes, regular investments
17 are planned for ongoing enhancements. The existing Supplier Portal has enhancement
18 funding earmarked in the Company’s 5-year business plan.

19
20 **III. CONCLUSION**

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

22 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
JAMES CONRAD
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: **Affiliate Support-Engineering & Construction Expense**
 Electric Vehicles
 Distributed Energy Resource Management System

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is James Conrad, and my business address is 827 Hausman Road, Allentown, PA 18104.

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

A. I am employed by PPL Services Corporation, a subsidiary of PPL Corporation (“PPL Corp.”) and an affiliate of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”) as Senior Director of T&D Smart Grid & Automation.

Q. Have you previously filed testimony in this matter?

A. Yes, I filed my directed testimony, PPL Electric Statement No. 20.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to direct testimony submitted by other parties regarding: (1) the Engineering & Construction Group expenses; (2) electric vehicles (“EVs”), including the Company’s EV Time-of-Use (“TOU”) Charging Rebate Program; and (3) the Company’s Distributed Energy Resource Management System (“DERMS”) and related costs. In particular, I respond to the direct testimony of: Office of Consumer Advocate (“OCA”) Witnesses Morgan (OCA St. 1), Hoyt (OCA St. 5), and Alexander (OCA St. 7); Sustainable Energy Fund (“SEF”) Witness Costlow (SEF St. No. 1);

Environmental Intervenors (“EI”) Witness Nelson (EI St. No. 1); and Walmart Inc. (“Walmart”) Witness Lyon (Walmart St. No. 1).

Q. Have you prepared any exhibits in support of your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

- PPL Electric Exhibit JC-1R – Answer to OCA VII-74
- PPL Electric Exhibit JC-2R – Answer to OCA XVI-12
- PPL Electric Exhibit JC-3R – EI Answer to PPL to EI-I-15
- PPL Electric Exhibit JC-4R – EI Answer to PPL to EI-I-17
- PPL Electric Exhibit JC-5R – EI Answer to PPL to EI-I-18
- PPL Electric Exhibit JC-6R – EI Answer to PPL to EI-I-19

II. AFFILIATE SUPPORT-ENGINEERING & CONSTRUCTION EXPENSE

Q. Does OCA Witness Morgan raise any concerns about the Company’s Engineering & Construction Group?

A. Yes, Mr. Morgan argues that the Company must explain in its rebuttal testimony the purpose and justification for the new Engineering and Construction Group positions. (OCA St. 1, p. 19.) Without that information, he recommends a reduction in operation and maintenance (“O&M”) expenses of \$88,000 (see LKM-14). (OCA St. 1, pp. 19-20.)

1 **Q. Do you agree with Mr. Morgan’s recommendation?**

2 A. No. Mr. Morgan appears to be basing his recommendation on a misunderstanding about
3 the positions in the Engineering & Construction Group. In his testimony, he asserts that
4 “[a]s of the FPFTY,” there were “approximately 13 newly created positions not yet posted
5 for recruitment.” (OCA St. 1, p. 19.) He further asks that the Company “explain, in its
6 rebuttal testimony, the budget purpose and justification for the additional new positions.”
7 (OCA St. 1, p. 19.)

8 To clarify, these are not truly new positions. In Attachment II-D-8e of the
9 Company’s filing requirements, PPL Electric used the term “newly created” when
10 referencing the positions because the Engineering & Construction Group itself was created
11 through a company reorganization in 2024. This group includes personnel that were
12 previously PPL Electric employees and contractors prior to the group’s creation, and they
13 largely perform similar or the same functions. As such, the open positions listed are not
14 necessarily new positions.

15
16 **III. ELECTRIC VEHICLES**

17 **Q. As an initial matter, do you propose any adjustments to or have any clarifications**
18 **regarding PPL Electric’s proposed Residential EV TOU Charging Rebate Program**
19 **(the “Proposed EV Program”)?**

20 A. Yes. As explained in the response to discovery request OCA VII-74, attached as PPL
21 Electric Exhibit JC-1R, \$120,000 in rebate costs in the Fully Projected Future Test Year
22 (“FPFTY”) were mistakenly included in the claim for capital in the FPFTY. The rebate

1 costs should have been included in the Company's O&M claim as part of the initial filing.
2 This has been adjusted in the Company's updated revenue requirement calculation
3 discussed in PPL Electric Statement No. 6-R.

4 In addition, I want to clarify a statement in my direct testimony about the Proposed
5 EV Program's TOU parameters. On page 5, lines 6-8 of my direct testimony, I had a
6 typographical error where I used "off-peak" instead of "on-peak" when describing the on-
7 peak hours under the Proposed EV Program. To clarify, the hours I listed in those lines of
8 testimony were meant to indicate PPL Electric's system on-peak hours, which occur from
9 4:00 PM to 7:00 PM in the summer months of June, July, and August, and two daily periods
10 in the winter months of December, January, and February - 6:00 AM to 9:00 AM and again
11 6:00 PM to 8:00 PM. All other hours would be considered off-peak hours. The Company
12 clarified this statement in discovery and committed to clarifying it in rebuttal testimony as
13 well.

14
15 **Q. At a high level, what categories of comments are raised in the other parties' testimony**
16 **regarding the Company's Proposed EV Program?**

17 A. The other parties' testimony generally reflects support for the concept of encouraging off-
18 peak charging through a limited, opt-in program, with suggested refinements that fall into
19 several common themes. At a high level, those themes are:

- 20 1. Alignment of time periods – whether and how the EV Program's peak/off-peak
21 (and any shoulder) definitions should align with existing time-varying rate periods.

2. Evaluation, metrics, and reporting – confirming the EV Program’s learning objectives and describing how the Company will measure results, including what will be reported and when.
3. Targeting and cost discipline – ensuring program design and marketing reasonably prioritize locations and customers where managed charging is most likely to provide operational value, while keeping costs proportional to a limited program.
4. Customer communications and implementation materials – developing and deploying customer-facing materials (e.g., program rules, enrollment communications, etc.) prior to launch.
5. Program duration and review – confirming the EV Program is time-limited and describing the process by which the Company and the Commission will consider continuation, modification, or termination based on results.

Q. How do the other parties’ witnesses address these themes?

A. The witnesses’ comments can be summarized by theme, as follows. This summary is intended to describe points of emphasis at a high level and not to restate the record in detail.

1. Alignment of time periods and minimizing customer confusion
 - o SEF Witness Costlow supports the Proposed EV Program to the extent that the program’s on-peak/off-peak times are synchronized with the Company’s existing Default Service TOU, citing customer confusion if the time periods differ and recommending approval with Default Service TOU times. (SEF St. No. 1, pp. 25-26.)

1 o OCA Witness Hoyt recommends revising the TOU design so it at least includes the
2 full on-peak period applied under the Generation TOU Rate during non-shoulder
3 months and provides discussion/illustration comparing the on-peak periods. (OCA
4 St. 5, pp. 101-02, 109).

5 o EI Witness Nelson alleges that mismatched peak/off-peak definitions versus the
6 currently available supply TOU rate are his primary concern and recommends
7 aligning any time-varying approach to the supply TOU periods. (EI St. No. 1, pp.
8 57-61.)

9 2. Evaluation, metrics, and reporting

10 o OCA Witness Hoyt places primary emphasis on establishing a comprehensive
11 evaluation plan (including how results will be compared across participant/non-
12 participant populations), data sharing with stakeholders, and an end-of-pilot review
13 process. (OCA St. 5, p. 101.)

14 3. Targeted marketing and cost discipline (including distribution value)

15 o OCA Witness Hoyt recommends targeted marketing to constrained areas from the
16 onset and proposes additional structure around customer enrollment based on
17 localized system constraints, while also discussing the system need/constraints
18 premise. (OCA St. 5, pp. 101-03.)

19 o OCA Witness Hoyt describes the total costs of the Proposed EV Program and
20 acknowledges the O&M expense in FPFTY generally aligns with year 1 projected
21 rebate costs but argues if the Company includes the whole cost of vendor services,
22 then it is overstated. (OCA St. 5, pp. 117-18.)

4. Customer communications and implementation materials

- o OCA Witness Alexander states that PPL Electric has not developed customer communications, application forms, or marketing materials identifying requirements/rules and, therefore, she cannot evaluate or endorse the customer-facing aspects of the proposal. (OCA St. 7, p. 9.)
- o OCA Witness Hoyt agrees with OCA Witness Alexander and recommends that, prior to approval, the Company produce customer communications and marketing materials for stakeholders to review. (OCA St. 5, p. 123.)

5. Program duration and review (pilot nature)

- o OCA Witness Hoyt recommends making the tariff language explicit that the program is temporary and will be reevaluated prior to continuation and also recommends Commission/stakeholder review at the conclusion of the program. (OCA St. 5, p. 101.)

Q. How does the Company address the key issues identified above regarding the Proposed EV Program?

A. The Company appreciates the generally supportive nature of the other parties' testimony regarding the Proposed EV Program and agrees that the record supports Commission approval of a limited, learning-oriented program with modest clarifications. The Company's responses are appropriately framed at a high level because most comments concern implementation details rather than the underlying premise of encouraging off-peak

charging and collecting data to inform future program design. Accordingly, the Company addresses the key issues as follows:

1. Alignment of time periods / minimizing customer confusion.

- o The Company agrees that time-period definitions should be clear and administrable and should minimize customer confusion but disagrees with OCA Witness Hoyt that “the TOU design should be revised to use a definition that at a minimum includes the entirety of the on-peak period applied to the Generation TOU Rate during the six non-shoulder months.” (OCA St. 5, p. 101.) The proposed program is a distribution-focused EV charging rebate program, not a generation-aligned program, and it is designed to produce learnings about customer responsiveness to incentives that are designed to help mitigate distribution constraints. Expanding the on-peak definition to mirror the generation TOU on-peak period (particularly in the six shoulder months) would require customers to avoid or shift additional charging during months when off-peak EV charging provides little to no distribution system value because local peak and equipment loading conditions are typically less stressed. As a result, expanding the defined on-peak period would risk rebate payments to customers for behavior changes that do not have the potential to materially defer or avoid distribution investments. Accordingly, PPL Electric supports maintaining the program’s on-peak definition as proposed, while using program metrics to monitor charging behavior (including any rebound or peak-edge

1 effects) and refine time periods in future iterations based on measured
2 distribution impacts and program results.

3 2. Evaluation, metrics, and reporting.

4 o The Company agrees that the Proposed EV Program should be evaluated and
5 that periodic reporting is appropriate. The Company will track participation,
6 charging behavior metrics, and customer satisfaction and provide summary
7 annual reporting consistent with the Proposed EV Program's learning
8 objectives as identified in the Company's response to OCA XVI-12, attached
9 as PPL Electric Exhibit JC-2R. However, PPL Electric disagrees that the
10 Commission should require the Company to develop a comprehensive
11 evaluation plan that establishes fixed, quantitative targets and milestones as a
12 condition of program approval. Requiring targets/milestones at the outset is not
13 appropriate for a learning-focused program intended to establish baseline
14 charging behavior and to inform future program and rate design.

15 o PPL Electric agrees that data collected from the proposed EV program should
16 be compared with data obtained from PPL Electric's proposed Act 129 Phase
17 V EE&C Plan's EV Program customers and from customers not participating
18 in either that program or the Proposed EV Program. However, PPL Electric
19 disagrees that the Commission should require the Company to specify data
20 collection techniques and comparison methodologies as a program pre-approval
21 condition. Those details are appropriately addressed in program
22 implementation, informed by data availability, privacy considerations, and the

1 final vendor approach. PPL Electric will develop and document a reasonable
2 methodology consistent with these constraints and report program data to
3 stakeholders, as noted previously.

4 3. Targeting and cost discipline.

5 o The Company agrees that marketing and enrollment strategies should be
6 designed to promote participation where managed charging is most likely to
7 provide operational value, while keeping program costs proportional to a
8 limited pilot. At the same time, the Company does not agree that participation
9 must be restricted solely to narrowly defined constrained areas or that separate
10 caps for non-constrained areas are necessary to achieve the Proposed EV
11 Program's objectives. Overly prescriptive restrictions could reduce program
12 participation and limit the representativeness of results needed to evaluate
13 charging behavior across the service territory.

14 o The Company can confirm that the full costs of the vendors' services are not
15 included for any year. Therefore, OCA Witness Hoyt's concern that the O&M
16 expenses are overstated is misplaced.

17 4. Customer communications and implementation materials.

18 o The Company agrees that customer-facing materials are important and will
19 finalize the necessary communications, program descriptions, and enrollment
20 materials in advance of program launch and share them with stakeholders.
21 These implementation artifacts are appropriately developed during
22 implementation and do not require tariff-level prescriptive detail.

1 5. Program duration and review.

- 2 o The Company agrees that the Proposed EV Program should have an initial term
3 of years and should be reevaluated based on results before any continuation
4 beyond that timeframe. The Company also supports appropriate Commission
5 oversight through reporting and, as needed, subsequent review informed by
6 program results.

7
8 **Q. Does the testimony of other parties' witnesses warrant additional, issue-specific**
9 **rebuttal beyond these high-level responses?**

10 A. Yes, but only in a limited respect. While most testimony supports approval with modest
11 refinements, EI Witness Nelson recommends rejecting the Proposed EV Program and
12 replacing it with a different delivery rate design. Because that recommendation would
13 expand the scope of issues to broader rate design and cost-of-service questions, the
14 Company provides targeted rebuttal.

15
16 **Q. Do you agree with EI Witness Nelson's recommendations?**

17 A. No. PPL Electric disagrees with Mr. Nelson's recommendation that the Commission reject
18 the proposed EV program and instead direct implementation of a time-varying residential
19 distribution delivery rate.

20

1 **Q. Why is that?**

2 A. PPL Electric’s proposed EV program is a capped, opt-in, distribution-focused learning
3 initiative designed to test customer responsiveness and generate actionable data while
4 limiting cost and bill impact risks. By contrast, implementing a new, broad residential
5 time-varying distribution delivery rate with a prescribed rate factor would be a major rate
6 design change with potentially significant bill impacts, equity considerations, operational
7 complexity, IT changes to the billing system, and would require a fully developed cost-of-
8 service and rate design record.

9 In discovery, Mr. Nelson has not performed any analysis on how his proposed TOU
10 rate would affect the Company’s proof of revenues, nor did he provide any calculations
11 about how his proposed TOU rate would affect the Company’s revenue allocation or rate
12 design. Mr. Nelson appears to simply make an assumption that his proposed TOU rate
13 would be “revenue neutral” within the existing residential rate class, as evidenced by his
14 discovery responses attached as PPL Electric Exhibits JC-4R through JC-6R.

15 The Company’s program approach is a prudent, lower-risk pathway to develop the
16 empirical evidence needed to inform whether broader rate design changes may be
17 appropriate in the future, and if so, how they should be structured to reflect cost causation,
18 minimize unintended consequences, and deliver measurable distribution value.

19
20 **Q. Does Walmart Witness Lyon make any claims about EV charging?**

21 A. Yes, he discusses Walmart’s experience with EV charging, with 1,200 public DC Fast
22 Chargers (“DCFCs”) at 285 locations in 43 states, with a base configuration of eight stalls

1 supplied by 400 kW units with two handles each, with additional units added depending
2 on the site. (Walmart St. No. 1, p. 23.) Mr. Lyon claims participation in public EV space
3 supports Walmart's clean energy and carbon reduction goals, the nation's overall EV
4 infrastructure, drivers in local communities and along travel corridors, and encourages
5 more people to choose an EV. (Walmart St. No. 1, p. 23.) He avers that Walmart considers
6 electric rates when installing or siting EV charging infrastructure, which is informed by the
7 tariff under which electricity is provided. (Walmart St. No. 1, p. 24.)
8

9 **Q. Do you have a response to these claims?**

10 A. Yes. PPL Electric acknowledges Walmart's experience with public EV charging and
11 agrees that rate design can influence the economics of EV charging infrastructure
12 investment. However, Walmart's testimony relates to third-party public DC fast charging
13 and associated commercial rate structures, which is distinct from the Company's proposed
14 residential, distribution-focused EV charging rebate program.

15 PPL Electric remains open to constructive stakeholder dialogue on how best to
16 support efficient public charging buildout through appropriate tariffs and rate design, but
17 those issues are separate from—and not a basis to deny—the Company's Proposed EV
18 Program.
19

20 **Q. What recommendations does Walmart Witness Lyon make?**

21 A. While he acknowledges that PPL Electric does not offer distribution rates specifically for
22 third-party-owned public DCFC EV stations, Mr. Lyon recommends DCFC EV charging

1 rates specifically designed for public charging at third-party locations. (Walmart Statement
2 No. 1, p. 22.) He claims that DCFC EV rate structure and other initiatives will help build a
3 strong public network of DC fast chargers, which will support the EV industry and encourage
4 transition by eliminating range anxiety and other challenges. (Walmart St. No. 1, p. 22.) He
5 also recommends a rate structure that encourages investment in public DCFC equipment and
6 EV stations, stating that rates should “be volumetric in nature and created in such a way to
7 recover the utility’s cost without cross subsidization while also providing the best use case for
8 the DCFC owner operator.” (Walmart St. No. 1, p. 24.) He further recommends that the
9 Commission require PPL Electric to work with interested stakeholders and develop an EV
10 charging-specific rate and tariff for third-party-owned public DCFC EV stations, and seek
11 approval of such no later than one year from the date of the final order in this case. (Walmart
12 St. No. 1, pp. 24-25.) He also claims that EV specific rates are needed to support third-party
13 investment. (Walmart St. No. 1, pp. 24-25)

14
15 **Q. Do you agree with these claims and recommendations?**

16 A. PPL Electric agrees in part and disagrees in part with Mr. Lyon’s recommendations
17 regarding development of EV charging-specific rates for third-party public DC fast
18 charging.

19
20 **Q. Please explain.**

21 A. PPL Electric agrees that it is appropriate to evaluate whether existing rate designs for high-
22 load-factor and low-load-factor public DCFCs are sending efficient price signals and

1 appropriately reflecting cost causation without cross-subsidization. The Company also
2 agrees that stakeholder engagement is important when considering new tariffs.

3 However, PPL Electric disagrees that this rate case is the appropriate vehicle to
4 mandate the development and filing of a specific DCFC tariff on an accelerated, one-year
5 timeline. Designing a DCFC-specific tariff requires careful cost-of-service evaluation,
6 consideration of operational and billing determinants (including demand characteristics),
7 coordination with broader rate design principles, and robust stakeholder input. PPL
8 Electric supports addressing these issues through the appropriate process and evidentiary
9 record, rather than through a prescriptive directive attached to approval of a separate
10 residential program.

11
12 **IV. DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM (DERMS)**

13 **Q. What claims does EI Witness Nelson make about PPL Electric's DERMS Capability**
14 **Costs?**

15 A. Mr. Nelson asserts that PPL Electric is proposing to include \$5 million DERMS Capability
16 in the FPFTY rate base. (EI St. No. 1, p. 51.) He notes that the Commission has already
17 addressed the Company's DERMS plan in its Order approving in part the Company's
18 Second DER Management Plan. (EI Statement No. 1, p. 52.) Further, he claims that the
19 results of the RFP and DER Orchestration Plan could significantly reduce the costs of the
20 Second DER Management Plan, and that the Company's Second DER Management Plan is
21 costly (at \$1,700 per device). (EI Statement No. 1, pp. 52-54.) Finally, he recommends that

1 the Commission reject the proposal to include the \$5 million in DERMS Capability costs in
2 rate base. (EI Statement No. 1, p. 54.)
3

4 **Q. Do you agree with these claims and recommendations?**

5 A. No.
6

7 **Q. Why do you disagree with Mr. Nelson?**

8 A. Mr. Nelson's positions are flawed for several reasons. First, the Company's \$5 million claim
9 for the FPFTY is actually understated due to the Commission's recent approval of the
10 Second DER Management Plan. *See Petition of PPL Elec. Utils. Corp. for Approval of its*
11 *Second Distributed Energy Resources Mgmt. Plan*, Docket No. P-2024-3049223 (Order
12 entered Dec. 3, 2025) ("*DER 2 Order*"). PPL Electric's original claim was based on the
13 parameters of its DER Management Pilot Program, which, among other things, placed an
14 annual cap of 3,000 on the number of DER Management devices that could be installed.
15 However, on December 3, 2025, the Commission approved PPL Electric's Second DER
16 Management Plan at Docket No. P-2024-3049223, and that Plan went into effect on January
17 3, 2026. *See DER 2 Order*, pp. 63-64. The Second DER Management Plan eliminates the
18 3,000 annual cap on DER Management device installations, meaning that every new DER
19 installed in the FPFTY will have a DER Management device installed. This is critical
20 because PPL Electric hit the annual cap in December 2024 and October 2025. Moreover,
21 PPL Electric's projected DER growth, which was in the cost-benefit analysis that the
22 Commission relied upon in approving the Second DER Management Plan, shows an

1 estimated 11,000 DERs installed in 2026 and 12,100 DERs installed in 2027. Using the
2 weighted average cost of the DER Management devices of \$959 utilized in the Second DER
3 Management Plan proceeding (which I discussed further below), the Company would incur
4 capital costs of approximately \$10,549,000 in 2026 and \$11,603,900 in 2027. By comparison,
5 PPL Electric has claimed \$5 million for the FTY ending June 30, 2026, and \$5 million for the
6 FPFTY ending June 30, 2027. More importantly, as I discuss below, the \$5 million claims
7 for the FTY and FPFTY include IT infrastructure costs needed to support monitoring and
8 active management of DERs, not only the DER Management devices. Thus, PPL Electric's
9 FPFTY claim of \$5 million that Mr. Nelson disputes is actually substantially understated.

10 Second, the Commission has determined that PPL Electric's Second DER
11 Management Plan will produce significant benefits well in excess of its costs. In fact, the
12 Commission relied upon cost-benefit analysis prepared by PPL Electric Witness Steven
13 Wishart, which showed that the Company's proposal would produce net benefits of
14 approximately \$65.5 million on a net present value basis over the 2025-2030 period. *See id.*,
15 p. 59. Additionally, the Commission noted that after accounting for the reduced capital costs
16 and expenses from the Plan, the estimated revenue requirement impact would be
17 approximately \$4.5 million lower than it would be without the Plan. *See id.* Despite these
18 net benefits, Mr. Nelson proposes to deny PPL Electric rate recovery of capital costs that will
19 be incurred to achieve those benefits. From my perspective, that is an unreasonable position
20 and essentially penalizes the Company for pursuing these investments that have actually put
21 downward pressure on base rates.

1 Third, Mr. Nelson mischaracterizes the cost of the Company's DER Management
2 devices. He presents a per-device cost of approximately \$1,700 (see EI St. No. 1, p. 53.).
3 To develop that figure, Mr. Nelson appears to have merely taken the \$5 million in DERMS
4 Capability costs and divided it by 3,000 (i.e., the current annual cap on DER Management
5 device installations) to reach his claimed \$1,700 per-device cost (i.e., $\$5 \text{ million} / 3,000 =$
6 $\$1,666.67$). In actuality, the Company's two DER Management devices cost less than that,
7 i.e., approximately \$934 for the ConnectDER Bridge Device and \$1,440 for the Cellular
8 Gateway Device. Therefore, the DER Management device costs do not make up the
9 entirety of the \$5 million claim. In fact, using the weighted cost of \$959 per unit in PPL
10 Electric Witness Wishart's rebuttal testimony in the Second DER Management Plan
11 proceeding, which was used as part of his cost-benefit analysis adopted by the Commission
12 and should be in Mr. Nelson's possession, the costs of the DER Management devices only
13 made up approximately \$2.88 million of the Company's \$5 million claim for the FPFTY
14 (i.e., $\$959 \times 3,000 = \$2,877,000$). The other costs comprising the DERMS Capability costs
15 are the IT infrastructure needed to support the Second DER Management Plan, particularly
16 servers, as well as costs for installation, programming, and the DER Lab that reviews and
17 approves the inverters and DER Management devices. (

18 Fourth, Mr. Nelson's argument that the Request for Proposal ("RFP") and DER
19 Orchestration Plan could reduce the DERMS Capability costs in the FPFTY completely
20 lacks merit. Under the Commission's December 3, 2025 Order, the Commission approved
21 PPL Electric's Second DER Management Plan with two minor modifications: (1) within
22 12 months of the Order's entry date, PPL Electric shall file a DER Orchestration Plan with

1 the Commission and provide an evaluation of 3 different flexible interconnection
2 approaches; and (2) within 12 months of the Order's entry date, PPL Electric must conduct
3 an RFP from third-party aggregators and original equipment manufacturers ("OEMs")
4 about providing DER aggregation services to the Company. *See Petition of PPL Elec.*
5 *Utils. Corp. for Approval of its Second Distributed Energy Resources Mgmt. Plan*, Docket
6 No. P-2024-3049223, pp. 58, 60, 63-64 (Order entered Dec. 3, 2025). Although Mr.
7 Nelson cites the RFP and DER Orchestration Plan as reasons why the Company's actual
8 capital expenditures may be less than \$5 million, Mr. Nelson fails to acknowledge that the
9 Company will complete the RFP, provide the flexible interconnection evaluation, and file
10 its DER Orchestration Plan by December 3, 2026, which is approximately halfway through
11 the FPFTY.

12 Due to this timing, I do not see how any of those three requirements could reduce
13 the Company's DERMS Capability costs in the FPFTY. Indeed, after the RFP is
14 conducted, PPL Electric will need time to evaluate the bids, secure contract(s) with the
15 winning bidder(s), and stand up their services for implementation. Likewise, the Company
16 would need time to implement any of the flexible interconnection approaches that it
17 evaluates. Furthermore, the DER Orchestration Plan would be subject to litigation before
18 the Commission. The Second DER Management Plan took approximately 19 months to
19 litigate. Given the lengthy litigation over the Second DER Management Plan, I fail to see
20 how the Company could fully litigate the DER Orchestration Plan before the end of the
21 FPFTY, let alone implement it in sufficient time to have any impact on the Company's
22 capital costs in the FPFTY. Lastly, even assuming that the RFP, flexible interconnection

1 evaluation, and DER Orchestration Plan filing could somehow affect the Company's
2 capital costs, it certainly would not stand to reason that the Company would incur \$0 of
3 capital costs in the FPFTY. In fact, up until the time those various items could be
4 implemented, PPL Electric would continue incurring capital costs associated with the
5 Second DER Management Plan, including the installation of DER Management devices.
6 Yet, Mr. Nelson recommends that the entire \$5 million in capital costs for the FPFTY be
7 disallowed.

8 Finally, Mr. Nelson only disputes the Company's FPFTY capital claim of \$5
9 million. He does not dispute any capital costs or accumulated depreciation for: (1) the FTY
10 ending June 30, 2026, under which the Company incurred costs under the DER
11 Management Pilot Program from July 1, 2025, to January 2, 2026, and has been incurring
12 costs under the Second DER Management Plan since January 3, 2026; and (2) the HTY
13 ending June 30, 2025, or any other prior periods. (See PPL Electric Exhibit JC-3R [EI
14 Answer to PPL to EI-I-15].) These capital expenditures under the Company's
15 Commission-approved DER Management Pilot Program and the Second DER
16 Management Plan are reasonable and prudent, and by the same logic, PPL Electric's capital
17 expenditures in the FPFTY should be recoverable.

18
19 **V. CONCLUSION**

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

21 **A.** Yes, it does.

WITNESS: James Conrad
Daniel Johnson

PPL Electric Utilities Corporation
Response to the Set VII Data Requests of the
Office of Consumer Advocate (OCA)
Dated October 27, 2025
Docket No. R-2025-3057164

OCA VII-74

Identify the marketing and billing costs associated with the proposed EV charging rebate program and state whether those costs are included in the filing and where they are reflected in the proposed revenue requirement.

PPL Electric
Response

The EV TOU Rebate Program (“EV Proposal”) will be provided by a third-party vendor as a Software as a Service (“SaaS”) product. The costs include:

- \$125,000/year - Includes setup, program management, vendor management and fees, EV TOU rebate platform access. Includes 1,250 EV/EVSE devices (“Included Devices”) for rebate processing, and TOU enrollment and reporting.
- \$36/year – for each EV/EVSE device beyond the Included Devices.
- \$5,000 one-time setup fee - Includes setup and management of incentive processing for all customers.

Included in the \$125,000/year costs are marketing services which consist of setting up a website and sending an email blast to potentially interested customers. The marketing costs are de minimis to the \$125,000/year costs which is primarily the SaaS cost for the EV TOU rebate platform. The above-described costs are included in the IT Capital Plan – Grid & Pipeline Value stream represented in the Company’s plant in service claim in the Fully Projected Future Test Year (“FPFTY”).

There is an additional \$120,000 of O&M expenses in the FPFTY representing the cost of providing the rebates for the EV Proposal. The rebate costs were mistakenly included in the claim for capital in the FPFTY. The rebate costs should have

WITNESS: James Conrad
Daniel Johnson

been included in the Company's O&M claim as part of the initial filing. This matter will be addressed in rebuttal testimony.

WITNESS: James Conrad

PPL Electric Utilities Corporation
Response to the Set XVI Data Requests of the
Office of Consumer Advocate (OCA)
Dated November 25, 2025
Docket No. R-2025-3057164

OCA XVI-12

The following questions refer to the Direct Testimony of James Conrad and the Residential EV TOU Charging Rebate Program (“Program”) unless otherwise specified.

Reference page 6 of the Direct Testimony of James Conrad as well as PPL’s response to OCA’s DR VII-75. Please outline the specific objectives of the Program. For each objective, please describe the specific performance metrics and evaluation criteria the Company will use to determine whether the Program is achieving each stated objective. Please describe all relevant data, metrics, and/or evaluation methods necessary to assess performance as proposed

PPL Electric
Response

The EV TOU Charging Rebate Program’s overall objectives are: 1) alleviate potential constraints on the distribution system caused by residential EV charging; and 2) determine the capability to shift EV charging load through offering customer incentives.

To evaluate performance against the first objective, PPL Electric will assess whether program participation results in measurable reductions or shifts in EV charging load during peak periods. Using data collected through approved EVSE and telematics platforms, the Company will analyze load shapes, evaluate the percentage of charging occurring during defined off-peak hours, and analyze feeder and substation loading to identify any reductions in peak demand or deferred capacity needs.

To evaluate performance against the second objective, PPL Electric will measure enrollment, participation persistence, and behavioral response to incentive periods. Metrics will include the percentage of participants aligning charging with off-peak hours, kWh shifted off-peak, and the persistence of these behaviors over time. Results will inform future program design and planning assumptions related to EV load flexibility and grid reliability improvements.

15. Reference EI St. No. 1, p. 54. Mr. Nelson claims that “[i]t is premature to include these costs within the Company’s rates, given the uncertainty around the magnitude of these costs, the third-party aggregators’ RFP, and the development of the DER Orchestration Plan.”
- a. Does Mr. Nelson dispute that the DER Management devices that are already installed are used and useful and in the public service? If so, please explain in detail how he reached that conclusion and provide all documents relied upon by him in reaching that conclusion and in responding to this discovery request.
 - b. Does Mr. Nelson dispute the amount of DERMS Capability costs that have already been incurred through the end of the Historic Test Year (“HTY”) or to date in the Future Test Year (“FTY”)? If so, please quantify the amount of those costs which he disputes, explain how he reached that conclusion, provide all supporting calculations, and provide all documents relied upon by Mr. Nelson in reaching that conclusion and in responding to this discovery request.
 - c. Please explain in detail how these capital investments could not be considered used and useful and in the public service if installed in the FPFTY.
 - d. Please provide all analyses performed by Mr. Nelson on the amount of DERMS Capability costs that would be reduced through the third-party aggregators’ RFP and the development of the DER Orchestration Plan.
 - e. Does Mr. Nelson agree that the Commission’s Final Order in the Second DER Management Plan proceeding directs PPL Electric to conduct the third-party aggregator Request for Proposal (“RFP”) within 12 months of the Final Order’s entry, i.e., by December 3, 2026? If so, please explain in detail how a potential third-party aggregator would be selected and utilized in sufficient time before the end of the FPFTY to have any impact on the DERMS Capability costs incurred in the FPFTY.
 - f. Does Mr. Nelson agree that the Commission’s Final Order in the Second DER Management Plan proceeding directs PPL Electric to file the DER Orchestration Plan within 12 months of the Final Order’s entry date, i.e., by December 3, 2026, and that such DER Orchestration Plan would be subject to litigation and approved by the Commission? If so, please explain in detail how the DER Orchestration Plan would be litigated and approved in sufficient time before the end of the FPFTY to have any impact on the DERMS Capability costs incurred in the FPFTY.

EI Response:

- a. It is Mr. Nelson’s understanding that a determination of cost recovery is being made in this proceeding and has not yet been made. See also EI St. No. 1, p. 52, footnote 106 and p. 53, footnote 109.
- b. Mr. Nelson does not dispute the magnitude of costs the Company has incurred to date.
- c. As Mr. Nelson is not an attorney, he cannot render a legal opinion on when a given asset is deemed “used and useful” under Pennsylvania law, nor can he speculate on the

application of the law to hypothetical future events. It is Mr. Nelson's understanding that the prudence of a cost also bears on whether it is recoverable in this proceeding. See CAUSE-PA St. No. 1, p. 5, line 7 – p. 6, line 9.

- d. Mr. Nelson did not conduct the requested analysis. However, Mr. Nelson is aware that autonomous smart inverter settings are used in other jurisdiction to address local distribution system disturbances from small DERs and that autonomous setting would clearly be more cost effective than what PPL is doing with its DERMS for small DERs. See Mr. Nelson's Direct and Surrebuttal testimonies in Docket No. R-2024-3049223.

In Mr. Nelson's opinion, the DER Orchestration Plan should seek to determine the most reasonable investment pathway for monitoring and, potentially controlling, DERs. PPL has predetermined the most appropriate pathway for monitoring and controlling small DERs prior to the study. It is Mr. Nelson opinion that PPL's approach is imprudent as it is not cost effective.

- e. Mr. Nelson agrees that the Commission's Final Order in the Second DER Management Plan proceeding directs PPL Electric to conduct the third-party aggregator Request for Proposal ("RFP") within 12 months of the Final Order's entry. To the best of Mr. Nelson's awareness, that Order did not dictate a specific time period in which the Company must incur costs associated with the RFP. See also PPL-EI I-15(d).
- f. See PPL-EI I-15(e).

17. Reference EI St. No. 1, p. 61. How many customers does Mr. Nelson project would receive service under his TOU rate proposal in the FPFTY? Please provide all supporting calculations, workpapers, and documents relied upon by Mr. Nelson in developing that projection.

EI Response:

Mr. Nelson has not conducted such analysis. Many factors may inform the number of customers that take service under any voluntary rate, including how well PPL markets the rate to prospective customers.

18. Reference EI St. No. 1, p. 61. Please provide all analyses performed by Mr. Nelson on how his proposed TOU rate would affect the Company's proof of revenues in this proceeding.

EI Response:

Mr. Nelson did not conduct the requested analysis. PPL would be best positioned to conduct the requested analysis, which could be done as part of a compliance filing or in rebuttal.

19. Reference EI St. No. 1, p. 61. Please provide all analyses performed by Mr. Nelson on how his proposed TOU rate would affect the Company's revenue allocation in this proceeding.

EI Response:

The Company would simply make the rate revenue neutral with the default residential tariff and no adjustment would be required as the EV rate could be treated as a sub-class.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
JASON HUNT
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: Economic Development

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Jason Hunt. My business address is 320 Market Street, 4th Floor,
4 Strawberry Square, Harrisburg, Pennsylvania 17101.

5

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

7 A. I am employed by PPL Services Corporation as Manager of Business and Economic
8 Development, supporting PPL Electric Utilities Corporation (“PPL Electric” or the
9 “Company”).

10

11 **Q. Have you previously filed testimony in this matter?**

12 A. Yes. I previously submitted direct testimony on behalf of the Company, PPL
13 Electric Statement No. 21.

14

15 **Q. What is the purpose of your rebuttal testimony?**

16 A. I will respond to recommendations concerning PPL Electric’s Economic
17 Development proposal, i.e., the Opportunity Pennsylvania Program. I organize the
18 opposing testimony into shared themes and explain why the Opportunity
19 Pennsylvania Program is reasonable, aligned with PPL Electric’s core obligations,
20 and designed to benefit customers by helping communities prepare competitive
21 sites and attract investment.

22

23

1 **II. SUMMARY OF OPPOSING POSITIONS AND THEMES**

2 **Q. How do you summarize the opposing testimony?**

3 A. The witnesses raise four recurring themes: (1) that rate recovery for the Opportunity
4 Pennsylvania Program is inappropriate because benefits to customers are not
5 demonstrated (see, e.g., I&E St. No. 2, pp. 30–32; CAUSE-PA St. No. 1, p. 112);
6 (2) that the activities are governmental in nature or outside a utility’s core function
7 (see OCA St. 1, p. 24); (3) that prior Pennsylvania Public Utility Commission
8 (“Commission”) precedent or past PPL Electric proposals counsel against approval
9 (see I&E St. No. 2, p. 32); and (4) that programs of this kind risk mission drift or
10 permanence and lack coordination with government policy (see OSBA St. No. 1,
11 p. 5).

12
13 **III. THEMATIC RESPONSES**

14 **Q. Why does the Opportunity Pennsylvania Program benefit customers?**

15 A. PPL Electric’s system is capital-intensive, with many fixed delivery costs. When
16 communities attract new or expanding businesses, the additional load helps to
17 further optimize infrastructure utilization. Over time, spreading fixed costs across
18 a broader base can place downward pressure on unit delivery costs and improve
19 overall system efficiency for all customers. The Opportunity Pennsylvania
20 Program is a modest, structured way—\$400,000 annually—to help communities
21 complete essential site-readiness steps and compete for larger state and federal
22 awards. The program focuses on community preparedness, rather than subsidizing
23 any individual company, and employs reimbursement-based support and simple

1 accountability mechanisms to protect customers. Concerns that the Company has
2 not specifically “quantified” the benefits of this proposal (See I&E St. No. 2, p. 32.)
3 reflect an overly narrow conception of ratepayer benefit. From my perspective, the
4 Company’s proposal should be viewed through a broader lens: is it a reasonable
5 and prudent way for the Company to assist its communities to prepare for future
6 growth and reduce the risk of declining system utilization? A range of utilities in
7 other deregulated states operate similar programs approved by their commissions,
8 including Duke Energy’s Site Readiness Program;¹ American Electric Power’s
9 Quality Sites Program;² and National Grid’s ShovelReady Infrastructure and
10 Brownfields Redevelopment programs.³ Given the modest cost and broad potential
11 benefits, I believe, the Company’s economic development proposal meets that
12 standard.

13
14 **Q. Is the Opportunity Pennsylvania Program a governmental function or beyond**
15 **the utility’s role?**

16 A. The Opportunity Pennsylvania Program complements, rather than replaces,
17 governmental efforts. Economic development today requires coordinated planning
18 around energy availability, timing, and reliability—factors that are central to an

¹ Duke Energy’s Business & Economic Development Website: <https://www.duke-energy.com/partner-with-us/economic-development/site-readiness-program>

² American Electric Power’s Business & Economic Development Website: <https://www.aepnationalcustomers.com/business/industry-solutions/ebd>

³ National Grid’s Business & Economic Development Website: <https://www.shovelready.com/programs.asp>

1 electric utility's responsibilities. By engaging early with communities and their
2 partners, PPL Electric helps identify infrastructure needs, clarify timelines, and
3 reduce uncertainty. This is prudent system planning that aligns with PPL Electric's
4 obligation to serve present and future load safely, reliably, and cost-effectively.

5

6 **Q. How do you respond to concerns about precedent?**

7 A. References to prior proposals do not reflect the Opportunity Pennsylvania
8 Program's targeted design. The Program focuses on site readiness, infrastructure-
9 related due diligence, and alignment with public programs such as Pennsylvania
10 SITES ("PA SITES"), which differ meaningfully from broader community
11 initiatives cited by opposing testimony (see I&E St. No. 2, p. 32). The question
12 before the Commission is whether this specific proposal is reasonable and in
13 customers' interests based on today's circumstances and the program's safeguards.

14

15 **Q. What safeguards protect customers?**

16 A. The Opportunity Pennsylvania Program is intentionally small, focused, and
17 reviewable. Funds are awarded through a competitive community application and
18 are primarily provided on a reimbursement basis for eligible, documented site-
19 readiness work. Support prioritizes planning, due diligence, and gap-filling steps
20 that help communities qualify for outside funding.

21 Importantly, the Company's proposal is not experimental or untested. It is
22 modeled on a successful program administered by the Company's regulated
23 affiliate utilities in Kentucky. As detailed in my direct testimony, the Opportunity

1 Kentucky Program has driven significant job creation and private capital
2 investment, while leveraging substantial additional state funding. The
3 Pennsylvania proposal adapts those proven best practices to address the specific
4 needs of and funding opportunities available to communities within PPL Electric's
5 service territory.

6 Furthermore, the program is subject to Commission oversight in future
7 proceedings, ensuring it can be adjusted or discontinued if it does not deliver value
8 (see OSBA St. No. 1, p. 5).

9

10 **Q. How does the Opportunity Pennsylvania Program coordinate with**
11 **Commonwealth initiatives?**

12 A. The Opportunity Pennsylvania Program is designed to complement
13 Commonwealth initiatives, including PA SITES. Program support helps
14 communities complete early-stage work—such as engineering due diligence or
15 preliminary site preparation—that is often necessary to compete successfully for
16 PA SITES grants and other programs. In this way, a small utility investment can
17 help unlock larger public and private dollars for projects within PPL Electric's
18 service territory.

19

20 **Q. Why is the Opportunity Pennsylvania Program timely and necessary?**

21 A. Energy availability, reliability, and speed-to-service increasingly shape site
22 selection decisions for manufacturing and other energy-intensive projects. Absent
23 a program like the Opportunity Pennsylvania Program, communities must navigate

1 these requirements on their own, and success can depend on hope rather than
2 preparation. With the Opportunity Pennsylvania Program, PPL Electric serves as
3 a catalyst—helping communities be bold, close readiness gaps, and compete
4 effectively so that families, small businesses, and all customers benefit from new
5 jobs and opportunities.⁴ The technical assistance portion of this program is
6 especially timely, as it is intended to help ensure that communities in the
7 Company’s service territory with land available are able to take full advantage of
8 the PA SITES funding, regardless of their community’s capacity to compile grant
9 applications on their own. A meaningful portion of the Company’s service territory
10 consists of small, rural communities, and many communities in PPL Electric’s
11 service territory do not have the level of site preparation experience needed to
12 prepare successful applications. The Company believes that the proposed program
13 with the provided technical assistance will help fill this gap and encourage the
14 communities that PPL Electric serves to utilize resources that are available to them.

⁴ Southern Economic Development Council, “The Growing Role of Power Requirements in Economic Development Site Selection,” Feb. 16, 2025, <https://www.sedc.org/news/the-growing-role-of-power-requirements-in-economic-development-site-selection>; Greg Ip, “Economic Growth Now Depends on Electricity, Not Oil,” The Wall Street Journal, Mar. 27–28, 2025 (online/print). See article page: <https://www.wsj.com/business/energy-oil/economic-growth-now-depends-on-electricity-not-oil-40250941>; Site Selectors Guild & Development Counsellors International, “The State of Site Selection 2024/2025,” highlighting power constraints eliminating sites early. See overview pages: <https://siteselectorsguild.com/research/state-of-site-selection-2025/> and International Economic Development Council summary (Apr. 22, 2024): <https://www.iedonline.org/news/2024/04/22/community-updates/new-site-selection-research-from-dci-and-site-selectors-guild/>.

1 **IV. SPECIFIC RESPONSES TO OTHER PARTIES' DIRECT TESTIMONY**

2 **Q. How do you respond to the claim that the Opportunity Pennsylvania**
3 **Program's ratepayer benefits have not been demonstrated (I&E St. No. 2, pp.**
4 **30–32; CAUSE-PA St. No. 1, p. 112)?**

5 A. I disagree with their claims. Customer benefits flow from improved system
6 utilization and prudent planning that positions communities to attract load. The
7 Company proposes a modest annual investment of \$400,000 to help communities
8 prepare development-ready sites, leverage state and federal funds, and attract new
9 and expanding businesses into PPL Electric's service territory. As new load
10 connects to the system, fixed delivery costs are spread over a broader customer
11 base, placing downward pressure on rates and improving long-term affordability
12 for all customers. At the same time, grid upgrades associated with serving new
13 load enhance reliability and resiliency for existing customers across the network.
14 The Opportunity Pennsylvania Program's modest scale, focus on community site
15 readiness, and reimbursement structure address concerns about speculative
16 spending.

17

18 **Q. Do you agree that economic development is a governmental function and**
19 **outside of a utility's role (OCA St. 1, p. 24)?**

20 A. No. The Opportunity Pennsylvania Program supports, rather than supplants, public
21 programs. Across the country, regulated electric utilities routinely collaborate with
22 state and local governments to support site readiness, infrastructure planning, and
23 grant coordination. These partnerships reflect the reality that no single entity can

1 independently address the increasingly complex requirements of modern business
2 attraction and expansion. The Opportunity Pennsylvania Program is structured
3 squarely within this model: it leverages public funding, complements government-
4 led initiatives such as PA SITES, and helps communities more effectively access
5 external resources. Early utility involvement in site readiness is prudent system
6 planning and part of serving future load reliably and cost-effectively.

7

8 **Q. Do you believe that prior Commission precedent requires rejection of this**
9 **proposal (I&E St. No. 2, p. 32)?**

10 A. No. The Company's Opportunity Pennsylvania Program differs materially from
11 earlier concepts. The Community Betterment Initiative was focused on funding
12 social and humanitarian community needs. By contrast, the Opportunity
13 Pennsylvania Program is narrowly tailored to site readiness and infrastructure-
14 related due diligence and incorporates safeguards. The regulatory landscape has
15 also changed significantly since 2004. Since that time, numerous restructured states
16 have recognized that utility economic development—particularly when focused on
17 site readiness and infrastructure planning—is integral to efficient grid utilization
18 and long-term rate stability.

19

20 **Q. Are concerns about permanence and coordination valid (OSBA St. No. 1, p.**
21 **5)?**

22 A. No. The Opportunity Pennsylvania Program is modest in cost, coordinated with
23 Commonwealth priorities like PA SITES, and subject to future Commission

1 review. These features directly address concerns about mission drift or
2 permanence.

3

4 **V. RECOMMENDATION AND CONCLUSION**

5 **Q. What is your recommendation?**

6 A. I recommend that the Commission approve PPL Electric's Opportunity
7 Pennsylvania Program and associated cost recovery as filed. The proposal is
8 reasonable in scale, aligned with core utility responsibilities, coordinated with
9 Commonwealth initiatives, and designed to catalyze community-led economic
10 development that benefits customers across PPL Electric's service territory.

11

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

13 A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
SHARON LESKOWSKY
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

PUBLIC VERSION

**Topics: Adjustment to Depreciation Expense
 Infrastructure Investment & Jobs Act (IIJA) Cost Amortization
 Capitalization of Certain Vegetation Management Costs**

Dated: January 23, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sharon Leskowsky, and my business address is 645 Hamilton Street, Suite 9, Allentown, PA 18101.

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

A. I am employed as Assistant Controller by PPL Corporation, which is the parent company of PPL Electric Utilities Corporation (“PPL Electric” or the “Company”).

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted direct testimony, PPL Electric Statement No. 22.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to: (1) address an adjustment to the Company’s depreciation expense to incorporate the annual amortization of negative net salvage; (2) respond to adjustments and recommendations regarding the Company’s Infrastructure Investment & Jobs Act (“IIJA”) cost amortization; and (3) respond to testimony regarding the Company’s proposal to capitalize certain vegetation management costs. Specific to the last two points, I explain that it is appropriate for the Company to recover its deferred costs associated with pursuing IIJA funds over a three-year period and that Federal Energy Regulatory Commission (“FERC”) Electric Plant Instructions permit capitalization of the

clearing and grading of land and rights-of-way in the cost of construction and installation of plant.

Q. Please summarize the key issues and recommendations offered by the opposing witnesses that you address in your rebuttal testimony.

A. I&E Witness Keller and OCA Witness Morgan both recommend disallowance of the Company's claim for amortization of IIJA deferred costs. Mr. Keller further recommends that if the IIJA cost amortization claim is allowed, recovery of these expenses should be over 61 months as opposed to the Company's proposed period of three years. In addition, OCA Witness Morgan recommends that the Commission deny the Company's proposal to capitalize the vegetation management costs of first clearing and grading of land and ROW.

Q. Have you prepared any schedules in support of your rebuttal testimony?

A. Yes. Attached to my rebuttal testimony is PPL Electric Exhibit SL-1R [Answer to OCA III-18 SUPPLEMENTAL]. I am also co-sponsoring Schedule D-15 of PPL Electric Rebuttal Exhibit No. 1.

II. ADJUSTMENT TO DEPRECIATION EXPENSE

Q. Did the Company make any adjustment to its claim for depreciation expense during the discovery process?

A. Yes. As explained in the discovery response to OCA III-18 SUPPLEMENTAL, attached as PPL Electric Exhibit SL-1R, and as further explained in PPL Electric Witness Spanos's

1 rebuttal testimony (PPL Electric St. No. 11-R), PPL Electric has adjusted its depreciation
2 expense provided in PPL Electric Exhibit Fully Projected Future 1, Schedule D-15 to include
3 the annual amortization of negative net salvage that was not included in the initial rate case
4 filing. As Mr. Spanos explains in his rebuttal, PPL Electric's claim for annual amortization
5 of negative net salvage is \$34,583,774. That annual amortization amount consists of
6 \$34,649,552 for Distribution Plant and (\$65,777) of General Plant that has been allocated to
7 Distribution.

8
9 **III. INFRASTRUCTURE INVESTMENT & JOBS ACT (IIJA) COST AMORTIZATION**

10 **Q. How does I&E Witness Keller summarize the Company's claim for an IIJA cost**
11 **amortization?**

12 A. He states that the Commission "granted utilities the ability to defer costs associated with
13 pursuing funds via the IIJA provided the utility files a notice with the Commission at the
14 corresponding docket, and that the request for recovery of any such cost be made at the earliest
15 possible time." (I&E St. No. 2, p. 22.) He further states that the Company has spent a total
16 of \$633,000 in 2022 and 2023 and is requesting a three-year amortization of that amount.
17 (I&E St. No. 2, p. 23.)

18
19 **Q. Does Mr. Keller agree with the Company's claim?**

20 A. No.

21
22 **Q. What does Mr. Keller recommend?**

1 A. He recommends disallowance of the Company's entire claim; however, if the Commission
2 decides to allow recovery of these expenses over an amortized period, he recommends that
3 the 2022 and 2023 expense total of \$633,000 be amortized over 61 months as opposed to three
4 years, which he believes is in line with the Company's actual historic filing frequency as
5 discussed by I&E witness Zachari Walker. (I&E St. No. 2, pp. 23-24.) This would result in a
6 recommended allowance of \$124,525 ($\$633,000 \div 61 \text{ months} \times 12 \text{ months}$), which he rounded
7 to \$125,000, or a reduction of \$86,000 ($\$211,000 - \$125,000$) to the Company's claim. (I&E
8 St. No. 2, p. 24.)
9

10 **Q. What is the basis for this recommendation?**

11 A. According to Mr. Keller, he "disagree[s] with the concept of a deferral for such cost as allowed
12 by the Commission in general, because a regulatory asset should be used for items that are:
13 (1) extraordinary; (2) unanticipated; (3) nonrecurring; and (4) substantial." (I&E St. No. 2,
14 pp. 23-24.) While he appreciates "the pursuit of regulated utilities applying for such grant
15 funding," Mr. Keller asserts that companies should be required and expected to apply for such
16 funding in all possible scenarios, which is not limited to the IIJA. (I&E St. No. 2, p. 24.) He
17 further states that "these costs are not extraordinary for PPL, were not necessarily
18 unanticipated, [and] are most certainly recurring expenses." (*Id.*) Lastly, he "do[es] not view
19 these expenses as substantial as far as PPL is concerned (\$633,000 spent over a two-year
20 period)." (I&E St. No. 2, p. 24.)
21

22 **Q. Do you agree with this recommendation?**

1 A. No.

2
3 **Q. Why not?**

4 A. I am advised by counsel that the Company meets all the applicable requirements, including
5 under the Commission's July 13, 2023 Order at Docket No. P-2022-3032929 ("*July 2023*
6 *Order*"), to recover these deferred expenses. In particular, the *July 2023 Order* authorized
7 utilities choosing to pursue federal funding for projects under IIJA to defer and record as an
8 IIJA-specific regulatory asset those costs incurred in preparing, applying for, administering,
9 and executing IIJA funding. In this case, the Company meets all the requirements of that
10 order. The Company incurred third party consultant expenses totaling approximately
11 \$633,000 to prepare and apply for one grant under the IIJA, and these incurred expenses were
12 not capitalizable costs. PPL Electric also submitted notice, on December 13, 2023, that the
13 Company established a regulatory asset for the IIJA-related incremental expenditures
14 incurred. Further, the Company maintains the required detailed accounting records of the
15 incremental expenditures and has a process established to track any and all funding once
16 received.

17 In addition, the Company has applied for and received one grant under the IIJA over
18 the past five years. The U.S. Department of Energy ("DOE") awarded the Company a "Smart
19 Grid" grant in support of its Grid of the Future Project and related smart grid initiatives. The
20 Company submitted its grant application on March 16, 2023. The third-party consultant costs
21 were incurred to support the preparation of the application, including drafting portions of the
22 submission and coordinating the required inputs with internal stakeholders. The Company

1 was selected by the DOE for the grant on October 18, 2023. The \$633,000 committed by PPL
2 Electric to this effort was a substantial expenditure by the Company, along with the limited
3 incurrence of this expense over the past five years, demonstrates that these expenditures were
4 substantial, extraordinary, and nonrecurring and, therefore, appropriate for deferred recovery
5 in this proceeding. The Company proposed a three-year amortization period to align with its
6 expected more frequent rate filings in the future as compared to its historical filing frequency.
7 Therefore, for the same reasons that the Company disagrees with Mr. Keller's adjustment to
8 the rate case expense normalization period (see PPL Electric St. Nos. 5-R and 6-R), PPL
9 Electric disagrees with I&E's proposed amortization period for the IIJA expenses that have
10 been deferred for recovery pursuant to the Commission's *July 2023 Order*.
11

12 **Q. Does OCA Witness Morgan make any recommendations regarding the IIJA cost**
13 **amortization?**

14 A. Yes, Mr. Morgan recommends "an adjustment that removes the amortization of the IIJA cost
15 of \$211,000 from the cost of service," citing OCA Exhibit LKM-8. (OCA St. 1, p. 16.) He
16 argues that "it is not reasonable to allow recovery of the deferred IIJA costs" because: (1) PPL
17 Electric "has not provided a Commission Order that authorizes the deferral"; (2) "the amount
18 for which recovery is sought is not extraordinary and substantial"; and (3) "the costs were not
19 unanticipated." (OCA St. 1, pp. 15-16.) Further, regarding the IIJA regulatory asset, he
20 argues that the Commission's *July 2023 Order* "gives the Company neither the explicit
21 authority to defer the costs nor assurance that the costs would be recovered." (OCA St. 1, p.
22 14.)

1

2 **Q. Do you agree with this recommendation?**

3 A. No.

4

5 **Q. Why not?**

6 A. As an initial matter, I am advised by counsel that Mr. Morgan misinterprets the *July 2023*
7 *Order*. The Commission clearly authorized utilities to establish an IIJA-specific regulatory
8 asset and to record the costs incurred in preparing, applying for, administering, and executing
9 IIJA funding to such regulatory asset. Specifically, Ordering Paragraphs 2 and 3 of the *July*
10 *2023 Order* provide the following:

11 2. That jurisdictional utilities choosing to pursue federal funding for
12 infrastructure projects under the Infrastructure Investment and Jobs Act,
13 Pub. L. No. 117-58, 135 Stat. 429 (2021), are authorized, subject to the
14 following conditions, to defer and record as an IIJA-specific regulatory
15 asset for accounting purposes those costs incurred in order to prepare,
16 apply, administer, and otherwise execute on federal funding
17 opportunities made available by the Infrastructure Investment and Jobs
18 Act, Pub. L. No. 117-58, 135 Stat. 429 (2021):

19 a. That the authorization granted for deferred accounting treatment
20 carries no assurance of future rate recovery;

21 b. That the utility shall make a claim of the deferred expenses at
22 the first available opportunity;

23 c. That the authorization for deferred accounting treatment be
24 limited to actual operations and maintenance costs and not include
25 capitalized costs; and,

26 d. That this Opinion and Order will in no way limit the ability of
27 any party to a future rate case to contest recovery of any of the
28 costs deferred pursuant to the limited authorization therein.

29

30 3. That a utility shall file a notice with the Commission at Docket No. P-
31 2022-3032929 upon establishing an IIJA-specific regulatory asset as

1 described in this Opinion and Order. Such notification shall be served
2 on the Commission's Bureau of 14 Investigation and Enforcement, the
3 Office of Consumer Advocate, and the Office of Small Business
4 Advocate.
5

6 Notably, the Commission expressly incorporated the OCA's recommended
7 conditions to the establishment of these regulatory assets, which were set forth in OCA's April
8 17, 2023 Answer to UGI Utilities, Inc.'s Petition for Clarification in that proceeding. These
9 conditions were that: (1) "the authorization for deferred accounting treatment carries with it
10 no assurance of future rate recovery"; (2) "the utility make the claim for the deferred expenses
11 at the first opportunity"; (3) "the authorization for deferral treatment be limited to actual
12 operations and maintenance expenses and not include capitalized costs"; and (4) "any Opinion
13 and Order in the instant matter not limit the ability of a party in a future case to contest the
14 recovery of any of the costs deferred pursuant to the limited authority by the allowance to
15 defer." (OCA's April 17, 2023 Answer, p. 3.)

16 As I explained previously, the Company meets all the applicable requirements for the
17 establishment of the IIJA regulatory asset and for deferred recovery of these costs, including
18 the requirements under the Commission's *July 2023 Order* that incorporated OCA's
19 recommended conditions. Further, if the OCA now believes those conditions are insufficient
20 to determine whether a regulatory asset could be established or whether these costs are
21 appropriate for deferred recovery, the OCA should have argued such in that proceeding.
22 Instead, the OCA stated that it "d[id] not disagree that the utilities' costs in this area may
23 satisfy the exception to the rule against retroactive recovery of past expenses" and asserted
24 that the Commission's approval of the regulatory assets' establishment "can only authorize

1 how the expenses are accounted for on the utilities' books pending that rate case." (OCA's
2 April 17, 2023 Answer, p. 3.) Yet, OCA witness Morgan now argues that the Company's
3 compliance with the Commission's *July 2023 Order* was insufficient to establish the
4 regulatory asset. If the OCA disagreed that the Commission's process for establishing the
5 regulatory assets was deficient, the OCA could have sought reconsideration of the
6 Commission's *July 2023 Order* or have objected to PPL Electric's and other utilities' letters
7 that were filed and served at the docket when those regulatory assets were established.
8 Instead, the OCA asserts for the first time in this proceeding that PPL Electric needed to avail
9 itself of a different process than the one set forth in the *July 2023 Order* to permissibly
10 establish the IIJA regulatory asset. Such a position flatly contravenes the *July 2023 Order*.
11 Furthermore, the Company agrees that the *July 2023 Order* gives no assurance of future
12 recovery of these deferred expenses. That determination was reserved for this proceeding,
13 which is PPL Electric's first opportunity to seek recovery of these costs. For the reasons I
14 have provided already, the Company meets all applicable requirements to recover these
15 deferred costs as proposed by PPL Electric in this proceeding.

16
17 **Q. Do you have any final observations about the IIJA-related expenditures?**

18 A. Yes. [BEGIN CONFIDENTIAL] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

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[END CONFIDENTIAL]

13

14 **IV. VEGETATION MANAGEMENT**

15 **Q. Does OCA Witness Morgan make a recommendation regarding the Company's**
16 **capitalization of the cost of first clearing and grading of land and ROW?**

17 **A.** Yes. Mr. Morgan recommends that the Commission deny the Company's proposal to
18 capitalize the cost of first clearing and grading of land and ROW. (OCA St. 1, pp. 28-29.) As
19 alleged support, he points to Section 7, *Land and Land Rights*, Paragraph A, of the FERC
20 Uniform System of Accounts ("USOA") and contends that "[t]he Commission would create
21 a very bad precedent by allowing the Company to capitalize these costs especially given that

there is no extenuating circumstance that necessitates the capitalization.” (OCA St. 1, pp. 28-29.)

Q. Do you agree with this recommendation?

A. No.

Q. Why not?

A. Mr. Morgan incorrectly asserts that FERC prohibits the capitalization of the first clearing and grading of land and rights-of-way, indicating it should be recorded as expense. In his direct testimony, he references FERC Electric Plant Instructions, Section 7, *Land and Land Rights*, Paragraph A, of the FERC Uniform System of Accounts, which states:

The accounts for land and land rights shall include the cost of land owned in fee by the utility and rights. Interests, and privileges held by the utility in land owned by others, such as leaseholds, easements, water and water power rights, diversion rights, submersion rights, rights-of-way, and other like interests in land. **Do not include in the accounts for land and land rights and rights-of-way costs incurred in connection with first clearing and grading of land and rights-of-way and the damage costs associated with the construction and installation of plant.** [Emphasis added]

(OCA St. 1, p. 28) (emphasis in original).

However, Mr. Morgan omits and overlooks key portions of FERC’s USOA that expressly authorize the Company to propose capital treatment of these expenses, subject to the Commission’s approval. Specifically, in the portion of Section 7, *Land and Land Rights*, Paragraph A, of the FERC Uniform System of Accounts quoted by Mr. Morgan, he fails to

1 include the next sentence, which provides greater clarity on its application to the Company's
2 proposal. Indeed, that passage from Section 7, with the omitted sentence included, provides
3 the following:

4 The accounts for land and land rights shall include the cost of
5 land owned in fee by the utility and rights. Interests, and
6 privileges held by the utility in land owned by others, such as
7 leaseholds, easements, water and water power rights, diversion
8 rights, submersion rights, rights-of-way, and other like
9 interests in land. Do not include in the accounts for land and
10 land rights and rights-of-way costs incurred in connection with
11 first clearing and grading of land and rights-of-way and the
12 damage costs associated with the construction and installation
13 of plant. **Such costs shall be included in the appropriate**
14 **plant accounts directly benefited.**

15 (emphasis added). If capitalized treatment were prohibited, FERC would not authorize
16 utilities to include those costs "in the appropriate plant accounts directly benefited." Further
17 guidance is found in FERC Electric Plant Instructions, Section 9, *Equipment*, Paragraph A, of
18 the FERC Uniform System of Accounts, which states:

19 The cost of equipment chargeable to the electric plant
20 accounts, unless otherwise indicated in the text of an
21 equipment account, includes the net purchase price thereof,
22 sales taxes, investigation and inspection expenses necessary to
23 such purchase, expenses of transportation when borne by the
24 utility, labor employed, materials and supplies consumed, and
25 expenses incurred by the utility in unloading and placing the
26 equipment in readiness to operate. **Also include those costs**
27 **incurred in connection with the first clearing and grading**
28 **of land and rights-of-way** and the damage costs associated
29 with construction and installation of plant. (emphasis added).

30 Thus, as indicated in the above references, FERC Electric Plant Instructions clearly
31 permit capitalization of the clearing and grading of land and rights-of-way in the cost of

1 construction and installation of plant. As explained in PPL Electric Witness Howell's rebuttal
2 testimony (PPL Electric St. No. 17-R), the proposed enhanced ROW work is substantially
3 similar to first clearing work associated with the construction of new facilities. Given that this
4 work supports a key reliability program to address one of the largest causes of system outages
5 and will support affordability by spreading out cost recovery of this work, the Commission
6 should approve PPL Electric's proposed accounting treatment.

7
8 **V. CONCLUSION**

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

10 **A.** Yes, it does.

WITNESS: John J. Spanos
Sharon Leskowsky

PPL Electric Utilities Corporation
Response to the Set III Data Requests of the
Office of Consumer Advocate (OCA)
Dated October 24, 2025
Docket No. R-2025-3057164

OCA III-18 Please state whether any historical retirement data has been adjusted or excluded from net salvage value calculations and analysis, and if so, please provide all details and support.

PPL Electric In Pennsylvania, there are no net salvage calculations or
Response analysis, just the five-year amortization of net salvage. In the last five years there have not been any adjustments or entries excluded from the net salvage amounts recorded.

Supplemental Response (12-16-2025)

In further response, the annual amortization of negative net salvage for distribution plant is \$34,649,552, as shown on I-7 of PPL Electric Exhibit JJS-3, which is the Depreciation Study for the Fully Projected Future Test Year ("FPFTY").

Due to a clerical error, PPL Electric's revenue requirement schedules failed to include the annual amortization of negative net salvage as part of the Company's annual depreciation expense (see, e.g., Schedules D-1, D-2, D-15, and D-17 of PPL Electric Exhibit Fully Projected Future 1). The Company's negative net salvage, which has been amortized over a five-year period, is recoverable in distribution rates under Pennsylvania law and Commission precedent as part of depreciation expense; therefore, the Company's revenue requirement was understated by the amount of the annual amortization of negative net salvage. See, e.g., *Penn Sheraton Hotel v. Pa. PUC*, 184 A.2d 324, 327-30 (Pa. Super. 1962); *Pa. PUC v. UGI Utils., Inc. – Elec. Div.*, 1994 Pa. PUC LEXIS 137, at *7-16 (Order entered July 27, 1994) (citations omitted).

The Company submitted revised schedules in its supplemental response to OCA I-1 reflecting this correction and the others described in that supplemental response (see OCA I-1 Attachment 231 SUPPLEMENTAL), along with updated cost of service and rate design exhibits and workpapers (OCA I-1 Attachment 232 SUPPLEMENTAL through OCA I-1 Attachment

WITNESS: John J. Spanos
Sharon Leskowsky

236 SUPPLEMENTAL), so that other parties do not inadvertently repeat these errors in their direct testimony.

As a result of the corrections identified in the supplemental response to OCA I-1, the Company's proposed increase in distribution base rate revenues should have been approximately \$389.32 million, i.e., approximately \$33.05 million more than the as-filed amount of approximately \$356.27 million. *Compare* OCA I-1 Attachment 231 SUPPLEMENTAL, Revised Schedule D-1, Col. 7, Line No. 1, *with* PPL Electric Exhibit Fully Projected Future 1, Schedule D-1, Col. 7, Line No. 1.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	Docket Nos. R-2025-3057164
Coalition for Affordable Utility Services and	:	C-2025-3057844
Energy Efficiency in Pennsylvania	:	
Office of Small Business Advocate	:	C-2025-3057889
Brad and Jennifer Woolley	:	C-2025-3057946
Office of Consumer Advocate	:	C-2025-3058130
Joint Solar Advocates	:	C-2025-3058251
PP&L Industrial Customer Alliance	:	C-2025-3058271
Convergent Energy and Power LP	:	C-2025-3058300
Rik Bhattacharyya	:	C-2025-3058846
Safiyah Junaid	:	C-2025-3058982
Stacey Kimmel-Smith	:	C-2025-3059151
John Gadomski	:	C-2025-3059330
	:	
v.	:	
	:	
PPL Electric Utilities Corporation	:	

**REBUTTAL TESTIMONY OF
VINCENT POPLASKI
ON BEHALF OF
PPL ELECTRIC UTILITIES CORPORATION**

Topics: Incentive Compensation

Dated: January 23, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Vincent Poplaski. My business address is Two City Center, 645 Hamilton
4 Street, 6th Floor, Allentown, PA 18101. A complete statement of my education and work
5 experience is attached to this testimony as **Appendix A**.

6
7 **Q. By whom are you employed and in what capacity?**

8 A. I am Vice President of Total Rewards for PPL Services Corporation, which provides
9 services to PPL Electric Utilities Corporation (“PPL Electric” or the “Company”).

10
11 **Q. Have you previously filed testimony in this matter?**

12 A. No.

13
14 **Q. What is the purpose of your rebuttal testimony?**

15 A. The purpose of my rebuttal testimony is to respond to the proposed adjustments to the
16 Company’s expense claim associated with its short-term and long-term incentive
17 compensation for eligible employees. Specifically, I will respond to portions of the direct
18 testimony of the Pennsylvania Public Utility Commission’s (“Commission”) Bureau of
19 Investigation and Enforcement (“I&E”) witness Christopher Keller (I&E St. No. 2) and
20 Office of Consumer Advocate (“OCA”) witness Lafayette Morgan (OCA St. No. 1) on
21 these subjects. As explained in my rebuttal testimony, their proposed adjustments to the
22 Company’s incentive compensation claim should be denied.

1
2 **Q. Are you sponsoring any exhibits or schedules with your rebuttal testimony?**

3 A. No.
4

5 **II. INCENTIVE COMPENSATION**

6 **Q. Before addressing the other parties' positions, could you please provide details about**
7 **the Company's short-term and long-term incentive compensation plans, including**
8 **who is eligible, what the incentive compensation is, and how the Company determines**
9 **whether to award the incentive compensation?**

10 A. Yes. The Company's short-term incentive plan is a cash award program that places a
11 portion of an eligible employee's pay at risk based on the Company's financial and
12 operational goals for the year and that individual's contributions toward achieving those
13 goals. The only employees eligible for the short-term incentive plan with an Earnings Per
14 Share ("EPS") metric are the PPL Corp. operating companies' presidents and executives.¹
15 For the operating companies' president, 55% of the short-term compensation is tied to
16 achieving PPL Corp. earnings per share from ongoing operations, while 45% is tied to
17 individual contributions and improvements in service and operational effectiveness, such
18 as meeting goals for electric reliability and customer satisfaction. For the operating
19 companies' executives, those respective percentages are 50% and 50%. All other

¹ To clarify, the employees must be in their roles as of as of December 31 *and the payment date of the short-term incentive* or must have died, became disabled, or retired during the plan year. Although the language in italics does not appear in the document shown on I&E Exhibit No. 2, Schedule 8, p. 4, the Company is in the process of updating that document to make that clarification.

1 employees eligible for the short-term incentive plan do not have an EPS metric plan payout.
2 Eligible non-executive employees' short-term incentives are tied to operational goals
3 (50%) such as reliability and customer satisfaction, annual strategic objectives (15%), and
4 individual performance (35%). Further details can be found in I&E-RE-II-11-D
5 Attachment 2a, which was attached to I&E witness Keller's direct testimony as I&E
6 Exhibit No. 2, Schedule 8, page 3.

7 The long-term incentive plan consists of two components: (1) restricted stock units
8 ("RSU"); and (2) performance units ("PU"). RSUs are PPL Corp. stock-equivalent units
9 representing a future delivery of a specified number of shares of PPL Corp. common stock
10 delivered over a three-year period contingent solely on an employee's continued service
11 with the Company. The value of the shares that may ultimately vest over the three-year
12 period may be greater than or less than the targeted value, depending on future increases or
13 decreases in PPL Corp.'s common stock share price. Employees in executive officer roles
14 and director roles are eligible for the RSU program. Additionally, employees in manager
15 level roles and a limited number of high-level individual contributor roles are in an eligibility
16 pool and may be selected for an RSU grant in a given year based on top performance. RSU
17 awards are a necessary component of the total compensation package to meet labor market
18 expectations for certain roles to attract and retain key talent necessary for long-term
19 operational success. RSU awards are not linked to operational or financial performance, and
20 vesting does not depend on the attainment of any financial metrics, a specific PPL stock price,
21 or any other individual or company performance goal. Again, the only criteria for an
22 individual to vest an RSU grant is continued employment with the Company. Thus, the

1 purpose of and reason for the long-term incentive plan is to retain employees. If an employee
2 ceases to be employed before the vesting period completes, the RSUs are forfeited. There are
3 no performance conditions (financial or other) upon which vesting of RSUs is contingent.

4 As for the PU grants, only employees in executive level roles are also eligible for
5 them. Executive officers receive a target number of PUs at the beginning of the performance
6 period. These PU grants are 100% “at risk” because total shares distributed at the end of
7 the performance period may vary from zero to the program maximum of 200% of the target
8 based on performance outcomes. They are also subject to the potential risk of forfeiture under
9 certain types of termination of employment. The performance period is three years, beginning
10 on January 1st of the first year, ending on December 31st of the third year. The actual number
11 of shares of common stock earned at the end of the performance period is determined based
12 on three types of performance criteria including PPL Corp.’s actual three-year total
13 shareowner return (“TSR”) compared to the TSR of companies in a particular industry index
14 or performance peer group, PPL Corp.’s three-year earnings growth compared to the projected
15 midpoint of ongoing earnings for the three-year performance period, and long-term
16 sustainability goals. For the 2025 grant, the PUs with long-term sustainability metrics aligned
17 executive compensation with PPL Corp.’s focus on leading indicators of service and
18 operational effectiveness, specifically employee and contractor safety and new generation
19 efforts, over the three-year performance period. The long-term sustainability metrics for the
20 2026 and 2027 awards are expected to be finalized by January 29, 2026.

21
22 **Q. What is the Company’s expense claim for incentive compensation?**

1 A. For the Fully Projected Future Test Year (“FPFTY”), the Company’s incentive
2 compensation expense claim is \$4.412 million. Of that amount, \$556,000 is tied to PPL
3 Electric officer cash awards under the short-term incentive compensation plan, and \$1.772
4 million is connected to the RSUs and PUs under the long-term incentive compensation
5 plan. The remainder is variable pay to non-union, non-officer PPL Electric employees that
6 is based on individual and operational performance.

7
8 **Q. What do I&E Witness Keller and OCA Witness Morgan recommend regarding the**
9 **Company’s expense claim for incentive compensation?**

10 A. I&E Witness Keller recommends “an allowance of \$2,362,000 for incentive compensation,
11 or a reduction of \$2,050,000 (\$4,412,000 - \$2,362,000) to the Company’s claim,” noting
12 that this proposal is based on “the removal of 50% of the Company’s claim related to cash
13 awards and 100% removal of the Company’s claim related to stock-based compensation.”
14 (I&E St. No. 2, pp. 18-19.) Mr. Keller’s position is that these amounts are based on goals
15 that are related to financial results, which he believes “do not provide any benefit to
16 ratepayers.” (I&E St. No. 2, p. 19.) He also points to the Commission’s recent decision in
17 Columbia Gas of Pennsylvania, Inc.’s (“Columbia”) 2025 Rate Case as alleged support,
18 averring that “the Commission removed 70% of Columbia Gas’ total incentive
19 compensation claim that was related to financial goals finding that it was not necessary in
20 providing safe and reliable service to ratepayers.” (I&E St. No. 2, p. 20.)

21 As for OCA Witness Morgan, he recommends that the portion of the claim
22 associated with the short-term and long-term incentive compensation plans be reduced by

1 50%, i.e., by \$955,000. (OCA St. 1, p. 11.) He says that there are two reasons for his
2 proposal: (1) “PPL has not adequately explained why the Company’s ability to meet
3 financial metrics is directly related to ratepayer benefits, such as safety, customer care,
4 customer satisfaction, or other benefits, and that this incentive compensation is necessary
5 to provide adequate service”; and (2) “if the financial targets are set properly, achieving
6 the financial targets would generate the funds needed to pay incentive compensation,” so,
7 “[i]n other words, the incentive plan should be self-funding.” (OCA St. 1, p. 10.)
8

9 **Q. Do you agree with these recommendations?**

10 A. No. I am advised by counsel that the Commission has allowed recovery of incentive
11 compensation in rates so long as the utility provides evidence linking the incentive
12 compensation plan with benefits to customers and improved operational efficiency.
13 Indeed, in PPL Electric’s last fully litigated base rate case, the Commission rejected
14 proposals to adjust the Company’s incentive compensation claim because it found that the
15 Company’s “incentive compensation plan is reasonable, prudently incurred, and is not
16 excessive in amount”; therefore, PPL Electric was “permitted full recovery of this
17 expense.” *Pa. PUC v. PPL Elec. Utils. Corp.*, Docket Nos. R-2012-2290597, p. 26 (Order
18 entered Dec. 28, 2012.) The Commission further declared that its “decision to allow this
19 incentive compensation expense is consistent with [its] prior decisions approving incentive
20 compensation programs that are focused on improving operational effectiveness.” *Id.*

21 Here, the Company’s short-term and long-term incentive compensation plans
22 benefit customers by driving improvements in operational effectiveness. As I explained

1 previously, the short-term incentive compensation plan has significant components (45%
2 for presidents, 50% for executives, and 100% for eligible non-executive employees) that
3 are specifically based on individual contributions to and general outcomes related to
4 service and operational effectiveness. Also, the PUs under the long-term incentive
5 compensation plan are based in part on the achievement of long-term sustainability goals,
6 which relate directly to service and operational effectiveness. Further, at the very least,
7 I&E and OCA fail to recognize that 100% of the RSUs are not dependent on financial
8 metrics, so any adjustment to the recovery of those amounts (which total \$813,000 of the
9 \$1.772 million of the long-term incentive compensation plan expense) should be rejected
10 even under their logic.

11
12 **Q. Do you agree that tying amounts of the incentive compensation to financial metrics**
13 **does not provide direct ratepayer benefits?**

14 A. Not at all. A strong financial profile allows the Company to attract the ongoing capital
15 required to make the necessary upgrades and improvements to its electric distribution
16 system to provide safe, reliable, adequate, efficient, and reasonable electric service. The
17 Company's strong financial profile also allows it to maintain strong credit ratings that
18 enable PPL Electric to attract debt financing at the lowest possible cost, which is passed
19 along to the ratepayers. Further, the Company achieves earnings goals by improving the
20 efficiency of its operation and maintenance ("O&M") expenditures. Those reduced
21 expenditures can be taken into account when evaluating the O&M expense claims in the

1 following base rate case, thereby helping put downward pressure on distribution rates.
2 Therefore, the Company's strong financial performance directly benefits ratepayers.
3

4 **Q. What are your thoughts on I&E Witness Keller's reliance on the Commission's**
5 **decision in the Columbia 2025 Rate Case?**

6 A. I am advised by counsel that the impact of that decision will be fully addressed in the
7 Company's Briefs. However, I will note that the Commission reasoned that Columbia
8 failed to explain how the incentive compensation tied to financial metrics would produce
9 direct ratepayer benefits. As I explained previously, it is incorrect for parties to conclude
10 that the achievement of financial metrics does not directly benefit ratepayers.
11

12 **III. CONCLUSION**

13 **Q. Please summarize your rebuttal testimony.**

14 A. As I stated throughout my testimony, I believe costs associated with both the short-term
15 and long-term incentive plans to be reasonable and necessary to ensure the attraction and
16 retention of talent, while encouraging successful performance across a portfolio of
17 performance metrics. While, for executives only, some performance metrics may be
18 financial in nature, they are in customers' best interest for the Company to have incentive
19 plans that encourage outcomes benefitting customers, including prudent management of
20 the Company's financial resources.
21

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

1 A. Yes, it does.

APPENDIX A

Vincent Poplaski

Vice President, Total Rewards
PPL Services Corporation
2 N. Ninth Street
Allentown, PA 18101-1179

Professional Experience

- 2022 – Current: PPL Services Corporation – Vice President, Total Rewards
- 2019 – 2022: Aramark – Vice President, Executive Compensation
- 2017 – 2019: JPMorgan Chase & Co – Vice President, Compensation
- 2015 – 2017: Willis Towers Watson – Senior Consultant (Talent & Rewards)
- 2012 – 2014: Mercer Consulting – Senior Associate (Total Rewards)
- 2010 – 2012: Goldman Sachs – Human Capital Management Associate
- 2005 – 2010: Mercer Consulting – Associate (Total Rewards)

Professional Memberships

- Society for Human Resource Management (SHRM)

Education

- Cornell University: B.A. in Economics and Sociology