BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY - ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

VOLUME II OF IV

PECO Statement No. 7:	**Direct Testimony of Ann E. Bulkley (and related exhibits)**
PECO Statement No. 8:	**Direct Testimony of Jiang Ding (and related exhibits)**
PECO Statement No. 9:	**Direct Testimony of Joseph A. Bisti (and related exhibits)**
PECO Statement No. 10:	**Direct Testimony of Megan A. McDevitt**
PECO Statement No. 11:	**Direct Testimony of Steven DeMott**
PECO Statement No. 12:	**Direct Testimony of Jacqueline F. Golden (and related exhibit)**

March 30, 2026

PECO Statement No. 7:
Direct Testimony of Ann E. Bulkley

PECO ENERGY COMPANY
STATEMENT NO. 7

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PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: ANN E. BULKLEY

SUBJECTS: OVERALL RATE OF RETURN, INCLUDING CAPITAL STRUCTURE RATIOS AND COST OF EQUITY, FOR PECO ENERGY – ELECTRIC DIVISION

DATED: MARCH 30, 2026

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Pennsylvania Public Utility Commission ("Commission") on behalf of PECO Energy Company – Electric Division ("PECO or the "Company"), a wholly-owned subsidiary of Exelon Corporation ("Exelon"). My testimony addresses the regulated electric utility operations of PECO within Pennsylvania.

Q. Please describe your education and experience.

A. I hold a Bachelor of Arts degree in Economics and Finance from Simmons College and a Master of Science degree in Economics from Boston University, with over 30 years of experience consulting to regulated utilities and the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings is attached as PECO Exhibit AEB-1 to this testimony.

Q. Please describe the purpose of your direct testimony.

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE") for the Company's electric operations in Pennsylvania to be used for ratemaking purposes, as well as assess the reasonableness of the Company's proposed capital structure.

Q. Are you sponsoring any exhibits in support of your direct testimony?

A. Yes. My analysis and recommendations are supported by the data presented in PECO Exhibit AEB-2 through PECO Exhibit AEB-13, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses supporting your ROE recommendation.

A. I estimate the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the business and regulatory risk of the Company relative to the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my recommended ROE for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section V explains my selection of a proxy group used to develop my analytical results.

- Section VI describes my analyses and the analytical basis for my recommended ROE in this proceeding.

- Section VII discusses the specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this proceeding.

- Section VIII assesses the reasonableness of the Company's proposed capital structure.

- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. The key factors that I have considered in developing my recommended ROE in this proceeding are:

- The United States Supreme Court's *Hope* and *Bluefield* decisions,[1] which established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.

- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).

- Company-specific considerations, since while the companies in my proxy group are generally comparable to PECO, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I consider the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall

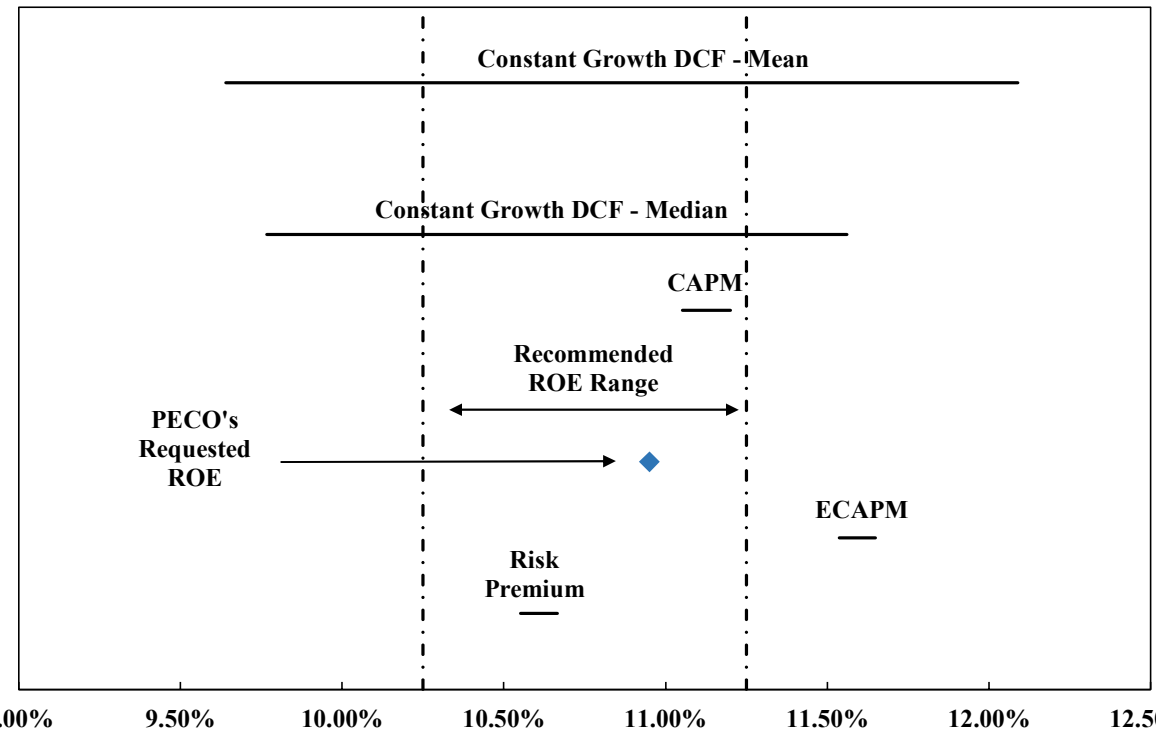
[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. What are the results of the models that you have used to estimate the cost of equity for the Company?

A. Figure 1 summarizes the range of results produced by the models that I have conducted based on data through the end of February 2026.

Figure 1: Summary of Cost of Equity Analytical Results



Q. What is your conclusion regarding the appropriate authorized ROE for the Company in this proceeding?

A. Considering the analytical results presented in Figure 1, current and prospective capital market conditions, as well as the level of regulatory, business, and financial risk faced by PECO's electric operations relative to the proxy group, a range for the Company's ROE

from 10.25 percent to 11.25 percent is reasonable, and within that range, the Company's requested ROE of 10.95 percent is reasonable.

Q. Is the Company's requested capital structure reasonable and appropriate?

A. Yes. The Company's proposed equity ratio of 53.40 percent is based on the company's projected financial statement. This equity ratio is well within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies.

III. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* decisions established the standards for determining the fairness or reasonableness of a utility's authorized ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.[2]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. The Commission follows the precedents of the *Hope* and *Bluefield* cases and acknowledges that utility investors are entitled to a fair and reasonable return. This position was set forth by the Commission as follows:

> In determining a fair rate of return, the Commission must adhere to the constitutional standards established by the United States Supreme Court in

[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

the seminal cases *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679, 692-93 (1923) (*Bluefield*) and *Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591*, 603 (1944) (*Hope Natural Gas*). In *Bluefield*, the Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield, 262 U.S. at 692-93. Twenty years later in *Hope Natural Gas*, the Supreme Court reiterated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.
>
> *Hope Natural Gas*, 320 U.S. at 603.[3]

This guidance is consistent with the principles that I employ to estimate the cost of equity and evaluate the reasonableness of the recommended ROE for the Company,

[3] Pennsylvania Public Utility Commission, Opinion and Order, Docket No. R-2024-3046932, *et al.*, PECO Energy Company – Gas Division, December 12, 2024, at 9-10.

including the principle that an allowed rate of return must be sufficient to enable regulated companies like PECO to attract capital on reasonable terms, and ultimately to continue to provide safe and reliable service to customers.

Q. How did the Court connect achieving a fair rate of return to providing utility service to customers?

A. The Court stated in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4]

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An authorized ROE that is adequate to attract capital at reasonable terms enables a utility to continue to provide safe, reliable service while maintaining its financial integrity. That return should be commensurate with returns required by investors elsewhere in the market for investments of comparable risk. It is important to recognize that equity investors have a choice of where to invest capital. It is reasonable to expect that equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract necessary new equity capital at reasonable cost.

[4] *Bluefield*, 262 U.S. at 679, 693.

Q. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, over the same period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q. What is the standard for setting the ROE in any jurisdiction?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking, requiring that the rates that are charged in any operating jurisdiction are incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. To maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for PECO's electric operations in Pennsylvania.

Q. Does the fact that the Company is owned by Exelon, a publicly traded company, affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for PECO, not its publicly traded parent, Exelon. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provides PECO the ability to attract capital on reasonable terms, both on a stand-alone basis and within Exelon.

Q. Is the regulatory framework, including the authorized ROE and equity ratio, important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for a utility's credit quality and financial stability in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the utility operates.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services to customers, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital on reasonable terms; (2) sufficient to ensure its financial

integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. Capital market conditions influence cost of equity models by affecting inputs in the model at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the models to estimate the required return for the subject company.

Analysts and regulatory commissions recognize the importance of considering how these conditions affect the results of the cost of equity estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is important to consider projected market data to estimate the return for the forward-looking period.

Q. What has the level of inflation been over the past several years?

A. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.40 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[5] While core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.00 percent.

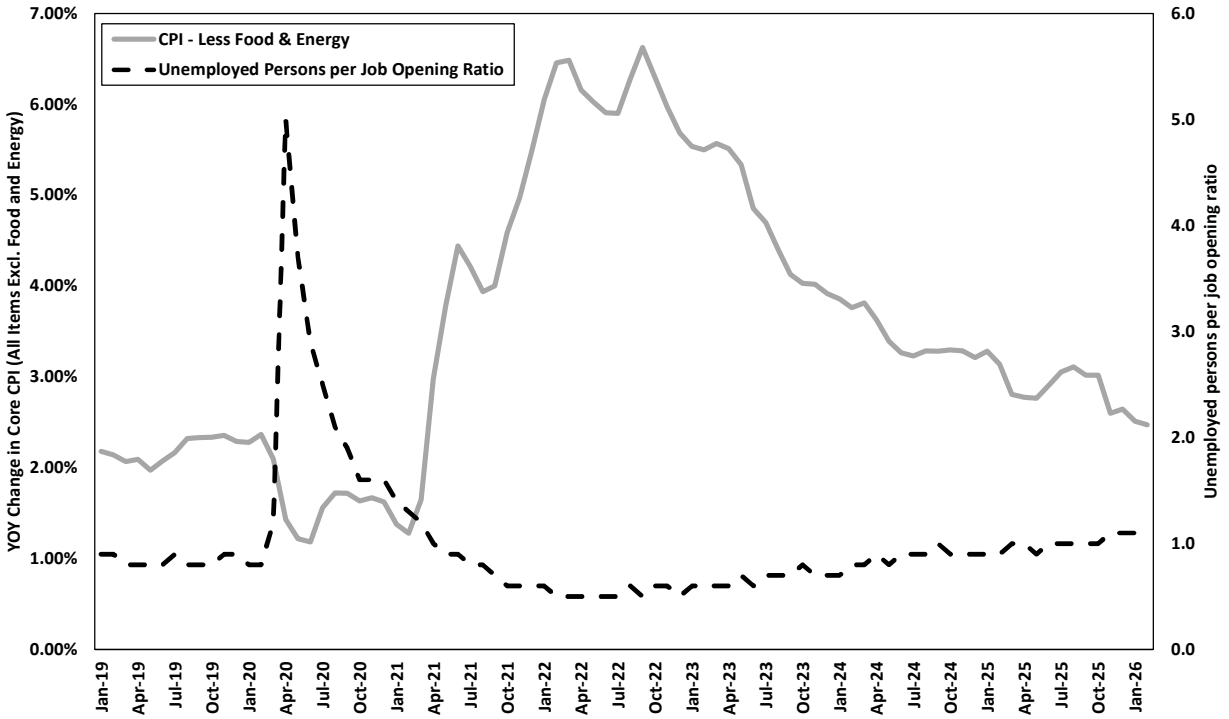
Because the Federal Reserve's dual mandate is to promote stable prices and employment, it is important to consider employment data in addition to inflation. The ratio of unemployed persons per job opening was 1.10 in January 2026.[6] While the ratio of unemployed persons per job opening increased slightly in recent months, it had been consistently at or below 1.00 between April 2021 and October 2025, which suggested a tighter labor market. The strength in the labor market allowed the Federal Reserve to prioritize reducing inflation by pursuing the restrictive monetary policy needed to achieve its 2.00 percent target benchmark.

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[5] Reade Pickert, "Core US Inflation Rises to 40-Year High, Securing Big Fed Hike," *Bloomberg,* October 13, 2022.

[6] The most recent data available at the time of this testimony; also January 2026 noted as "preliminary."

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to February 2026[7]



Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Between the March 2022 Federal Open Market Committee ("FOMC") meeting and the July 2023 FOMC meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 – 5.50 percent.

[7] Bureau of Labor Statistics; reflects data available as of March 13, 2026.

Q. How did yields on long-term government bonds respond to the Federal Reserve's normalization of monetary policy?

A. Since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has increased by over 350 basis points, increasing from 1.47 percent on December 15, 2021, to a peak of 4.98 percent on October 19, 2023. It currently remains well above 2021 levels (*i.e.*, 4.21 percent as of March 11, 2026).[8]

Q. Did the Federal Reserve recently reduce the federal funds rate?

A. Yes. The Federal Reserve reduced the federal funds rate by 50 basis points in September 2024, by 25 basis points in November and December 2024, and most recently by 25 basis points in September, October, and December 2025. While the Federal Reserve kept rates unchanged through the first five meetings in 2025, its decision to reduce the federal funds rate at the final three meetings in 2025 was due to an increase in the downside risk to employment in recent months.[9]

Q. What is the expected path of monetary policy over the near term?

A. At the January 2026 FOMC meeting, Chairman Powell noted that inflation remains "somewhat elevated" and that "while job gains have remain low, the unemployment rate has shown signs of stabilization."[10] As a result, the FOMC decided to maintain the federal funds rate range of 3.50 percent to 3.75 percent.[11] In March 2026, the FOMC indicated that "economic activity has been expanding at a solid pace" but also noted that uncertainty

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8 *S&P Capital IQ Pro*.

9 Federal Reserve, "Federal Reserve issues FOMC statement," Press Release, September 17, 2025, October 29, 2025, and December 10, 2025.

10 Federal Reserve, "Transcript of Jerome Powell's Press Conference," January 28, 2026.

11 *Id*.

about the economic outlook for the U.S. economy, referencing the implications of developments in the Middle East.[12]

Regarding the possible path of monetary policy, Chairman Powell indicated that the reductions since September have brought the federal funds rate "within a range of plausible estimates of [the] neutral" rate and therefore, the Federal Reserve is well positioned to rely on incoming economic data to determine the extent and timing of any additional changes in the federal funds rates.[13] The FOMC published a forecast of the federal funds rate at the March 2026 meeting that was unchanged from December 2025 projections of one reduction in December 2026 and potentially one reduction in 2027.[14]

Q. What has happened to the yields on long-term government bonds since the FOMC first reduced the federal funds rate in September 2024?

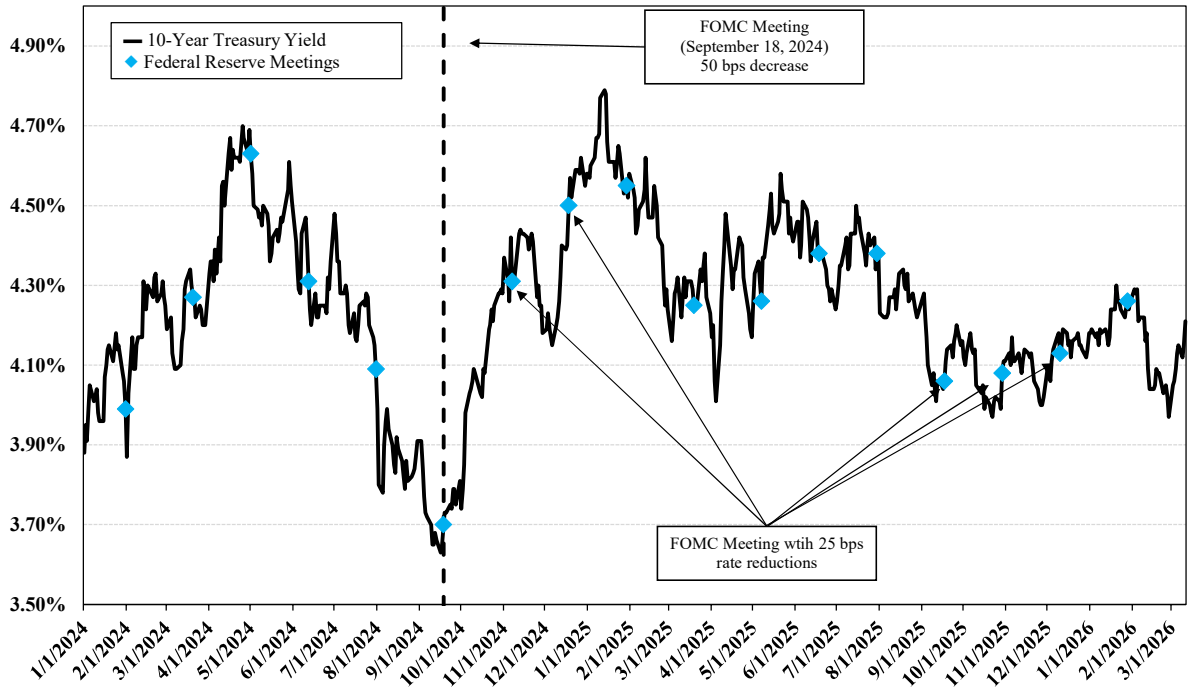
A. As shown in Figure 3, while the yield on the 10-year Treasury bond declined prior to the time of the first federal funds rate cut, the yield has generally increased since the September 2024 FOMC meeting. Further, while the yield on the 10-year Treasury bond has been volatile recently, as of March 11, 2026, the 10-year Treasury bond yield was 4.21 percent, which is generally consistent with levels seen in July 2024, two months prior to the first reduction in the federal funds rate.

[12] Federal Reserve, "Federal Reserve issues FOMC statement," Press Release, March 18, 2026.

[13] *Id.*

[14] Federal Reserve, "Transcript of Chair Powell's Press Conference", March 18, 2026.

Figure 3: 10-Year Treasury Bond Yield, January 2024 through March 11, 2026[15]



Q. Why have long-term interest rates remained above the levels at the time the Federal Reserve first reduced the federal funds rate in September 2024?

A. Ongoing policies of the current administration's economic plans have resulted in higher deficits, and persistent inflation. For example, since January 2025, the administration announced several sets of tariffs on each of the U.S.'s trading partners.[16] The implemented tariffs are largely viewed as inflationary. Inflation affects bonds, in particular long-term government bonds, because it erodes the value of future bonds payments. Therefore, in an inflationary environment, investors will demand higher returns on bonds to compensate for the added risk of inflation thus bond prices decline and the yields on bonds increase. The longer the duration of the bond, the greater the effect of inflation which is why inflation

[15] S&P Capital IQ Pro.

[16] Jennifer Clarke, "What Are Tariffs, How Do They Work and Why Is Trump Using Them?" *BBC News*, August 27, 2025.

risk is greater for long-term government bonds. The significant tariff increases implemented by the current administration increase the risk that inflation will remain elevated, which is why the yields on long-term bonds have not decreased and in fact have increased since the Federal Reserve first reduced the federal funds rate in September 2024. Further, the use of tariffs strains the relationship with trading partners, which could result in a reduction in the foreign demand for long-term U.S. government bonds resulting in additional upward pressure on long-term government bond yields.[17]

Q. What effect does the recent Supreme Court ruling have on the tariffs implemented by the administration in 2025?

A. On February 20, 2026, the Supreme Court ruled that the tariffs implemented in 2025 under the International Emergency Economic Powers Act were illegal. However, the administration responded to the ruling by imposing a 15 percent tariff on all goods imported into the U.S. under Section 122 of the 1974 Trade Act,[18] which allows a President to implement global tariffs up to 15 percent for a period of five months after which the approval of Congress is needed for continuation of the tariffs. Therefore, the administration is still able to at least temporarily impose global tariffs, which, as noted, will continue to place upward pressure on prices.

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[17] Karishma Vanjani, "U.S. Treasury Bonds Sell Off as 30-Year Yield Rises Most Since 1982," *Barron's*, April 9, 2025.

[18] Dearbail Jordan, "Trump says he will increase his new global tariffs to 15%," *BBC*, February 22, 2026.

Q. Have there been any other recent developments that may affect inflation and long-term government bond yields?

A. Yes. The war in Iran and the resulting increase in underlying oil prices will likely put upward pressure on inflation as increased oil prices not only increase gasoline prices for consumers, but also the prices of other products as well given that nearly all goods need to be transported from the place of production. The likelihood of continued elevated inflation suggests interest rates will remain higher in the near term.

Q. What are expectations for the yields on long-term government bonds?

A. While the Federal Reserve is forecasting additional cuts to the federal funds rate in 2026 and 2027, economists are still expecting elevated long-term interest rates. In the most recently published report by *Blue Chip Financial Forecasts*, the consensus estimate of economists is that the 30-year treasury bond yield will remain relatively stable and decrease only slightly from 4.80 percent in Q2/2026 to 4.70 percent in Q2/2027.[19] Additionally, the consensus estimate over the longer-term (*i.e.*, 2027–2031) is 4.60 percent.[20] Further, *Reuters* published the results of a survey of 75 bond strategists which suggests that aggressive tax and spending reforms could add over $3 trillion to the debt over the next decade. Bond strategists expect long-term bond yields to remain elevated even with the expectation that the Fed will decrease the federal funds rate because of inflation and a "resilient" economy.[21] This is important because it means that long-term interest rates are expected to remain elevated during the period that the Company's rates will be in effect.

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[19] *Blue Chip Financial Forecasts*, Vol. 45, No. 3, February 27, 2026, at 2.

[20] *Blue Chip Financial Forecasts*, Vol. 44, No. 12, December 1, 2025, at 14.

[21] Reuters, "Long Treasury yields to stay elevated as inflation, debt pressures blunt Fed easing: Reuters poll", October 14, 2025.

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A. It is important to consider current and projected market conditions in setting the forward-looking ROE due to its effect on the estimated cost of equity. Although the FOMC reduced the federal funds rate several times in late 2025, Chairman Powell has indicated that the Federal Reserve will continue to rely on incoming data to determine future adjustments to the federal funds rate. Further, long-term interest rates remain elevated and are expected to continue to remain elevated due to inflationary policies such as tariffs and tax cuts and the uncertainty regarding the Iran conflict and the increase in underlying energy costs. With long-term interest rates expected to remain relatively high, borrowing also remains relatively more expensive, and thus investors also demand a relatively high cost of capital, which means the cost of capital also remains relatively high.

V. PROXY GROUP SELECTION

Q. Please provide a brief profile of PECO.

A. PECO is a wholly-owned subsidiary of Exelon that provides electric transmission and distribution service to approximately 1.7 million customers in southeastern Pennsylvania.[22] Additionally, PECO also provides natural gas service to approximately 554,000 customers in southeastern Pennsylvania.[23] PECO is currently rated A- by Standard & Poor's ("S&P") and A2 by Moody's Ratings ("Moody's).[24]

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[22] PECO Energy website.

[23] PECO Energy – Gas Division, 2024 Annual Gas Report, April 9, 2025, at 63.

[24] S&P Global Ratings, "Exelon Corp. And Utility Subsidiary PECO Energy Upgraded to 'A-'; Outlook Stable," February 7, 2025; Moody's Ratings, Credit Opinion, PECO Energy Company, October 28, 2025.

Q. Why have you used a proxy group of publicly traded companies to estimate the cost of equity for PECO?

A. In this proceeding, I am estimating the cost of equity for PECO, a rate-regulated subsidiary of Exelon. Because the cost of equity is a market-based concept and PECO does not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if the Company was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. Using a proxy group moderates the effects of unusual events that may be associated with any one company. The companies included in the proxy group all possess a set of operating and risk characteristics that are substantially comparable to PECO's and thus provide a reasonable basis to derive and estimate the appropriate cost of equity for the Company.

Q. How do you select the companies included in your proxy group?

A. I have begun with the universe of companies that *Value Line Investment Survey* ("*Value Line*") classifies as Electric Utilities and applied the following screening criteria to select publicly traded companies that:

- pay consistent quarterly cash dividends because companies that do not pay dividends cannot be analyzed using the DCF model;
- have an investment grade long-term issuer rating;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- derive more than 70.00 percent of their total operating income from regulated electric operations; and,

- were not parties to a merger or transformative transaction during the analytical period relied on.

Q. What is the composition of your proxy group?

A. The screening criteria discussed results in a proxy group consisting of the companies shown in Figure 4 below and detailed in PECO Exhibit AEB-3.

Figure 4: Proxy Group

Company	Ticker
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Dominion Resources, Inc.	D
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
FirstEnergy Corporation	FE
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
PPL Corporation	PPL
Southern Company	SO
Xcel Energy Inc.	XEL

VI. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the overall rate of return for ratemaking purposes. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required cost of equity determined?

A. The required cost of equity is estimated using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group) in particular.

Q. What methods do you use to establish your recommendation regarding the Company's ROE in this proceeding?

A. As noted, I consider the results of the constant growth DCF, CAPM, ECAPM, and BYRP analyses.

Q. Is it important to use more than one analytical approach to estimate the cost of equity?

A. Yes. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded

finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[25] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[26] recommend the CAPM, DCF, and BYRP approaches.

Q. Has the Commission previously recognized the importance of considering the results of multiple cost of equity estimation models?

A. Yes, the Commission has recognized the benefits of using multiple models. For example, in Pennsylvania-American Water Company's most recent rate proceeding, the Commission rejected the recommendation of the Pennsylvania Bureau of Investigation & Enforcement ("I&E") recommendation to ignore the CAPM results and gave equal weight to I&E's DCF and CAPM results in determining an appropriate ROE for the utility. In doing so, the Commission concurred with the Administrative Law Judge's conclusion that the utility had "convincingly argued" that higher inflation, higher interest rates and capital costs exist and are likely to continue.[27]

Similarly, in a PPL Electric Utilities rate proceeding, the Commission noted that while it has traditionally relied primarily on the DCF method to estimate the cost of equity for regulated utilities, it recognized that market conditions were causing the DCF model to produce results that were much lower than other models such as the CAPM and Risk Premium:

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[25] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[26] Eugene Brigham, Louis Gapenski, *Financial Management: Theory and Practice*, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

[27] Pennsylvania Public Utility Commission, Pennsylvania-American Water Company, R-2023-3043189 and R-2023-3043190, July 11, 2024, at 194.

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[28]

The Commission ultimately concluded:

> As such, where evidence based on the CAPM and RP methods suggest that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[29]

A. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required cost of equity. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

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[28] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held Dec. 5, 2012, at 80.

[29] *Id*., at 81.

Q. What assumptions are required for the constant growth DCF model?

A. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are not objectively valid, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data do you use to calculate the dividend yield in your constant growth DCF model?

A. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annualized dividend and average closing stock prices over the 30-day, 90-day, and 180-day trading day periods ended February 28, 2026.

Q. Why do you use these averaging periods?

A. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q. Have you made any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected

first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share ("EPS"), dividends per share, and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate estimate of a company's long-term projected growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. As such, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects.[30] Accordingly, I have incorporated several sources of long-term EPS growth rates into the constant growth DCF model.

[30] Consistent with the assumption used in my analysis, five-year projected earnings growth rates have been relied upon by I&E in the constant growth DCF model in prior cases. *See, e.g.,* Pennsylvania Public Utility Commission, Docket No: R-2020-3018929, Opinion and Order, June 17, 2021, at 152-153.

Q. Which sources of long-term earnings growth rates do you use?

A. My constant growth DCF model incorporates three sources of long-term earnings growth rates: (1) *Zacks Investment Research* ("*Zacks*"); (2) *S&P Capital IQ*; and (3) *Value Line*.

Q. Have you previously relied on projected EPS growth rates provided by *Yahoo! Finance*?

A. Yes, however, *Yahoo! Finance* no longer reports consensus projected 3- to 5-year EPS growth rates. As a result, I have replaced this source with the consensus projected 3- to 5-year EPS growth rates reported by *S&P Capital IQ*.

Q. Why are projected earnings growth rates the appropriate growth rates in the DCF model?

A. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.[31]

Q. How do you calculate the range of results for the constant growth DCF models?

A. I calculate results using the average EPS growth rate from all three sources for each proxy group company. In addition, I calculate a low-end result for the constant growth DCF

[31] Consistent with the assumption used in my analysis, five-year projected earnings growth rates have been relied upon by I&E in the constant growth DCF model in prior cases. *See, e.g.,* Pennsylvania Public Utility Commission, Docket No: R-2020-3018929, Opinion and Order, June 17, 2021, at 152-153.

models using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, *S&P Capital IQ*, and *Value Line* projected EPS growth rates) for each of the proxy group companies, and use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company.

Q. What are the results of your DCF analyses?

A. Figure 5 summarizes the results of my DCF analyses, which are also provided in PECO Exhibit AEB-4.

Figure 5: Discounted Cash Flow Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results			
30-Day Avg. Stock Price	9.51%	10.80%	11.95%
90-Day Avg. Stock Price	9.64%	10.94%	12.09%
180-Day Avg. Stock Price	9.77%	11.07%	12.22%
Average	9.64%	10.94%	12.09%
Median Results			
30-Day Avg. Stock Price	9.68%	10.53%	11.41%
90-Day Avg. Stock Price	9.78%	10.63%	11.55%
180-Day Avg. Stock Price	9.84%	10.72%	11.73%
Average	9.77%	10.62%	11.56%

B. CAPM and ECAPM Analyses

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-

diversifiable or "systematic" risk of that security.[32] The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required return of an individual security
β = the beta coefficient of an individual security
r_f = the risk-free rate of return
r_m = the required return on the market as a whole

In this specification, the term ($r_m - r_f$) represents the market risk premium, which measures the relative riskiness of the security being evaluated. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

[32] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

Q. What risk-free rate do you use in your CAPM analyses?

A. I use three estimates of the yield on Treasury bonds: (1) the current 30-day average yield on 30-year Treasury bonds;[33] (2) the projected 30-year Treasury yield for Q2/2026 through Q2/2027;[34] and (3) the projected 30-year Treasury yield for the period 2027-2031.[35]

Q. What beta coefficients do you use in your CAPM analyses?

A. As shown on PECO Exhibit AEB-5, I use the beta coefficients for the proxy group companies as reported by *Value Line*, which are based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown on PECO Exhibit AEB-5 and PECO Exhibit AEB-6, I also consider another CAPM analysis that relies on the long-term average beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2025.

Q. How do you estimate the market risk premium in the CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in PECO Exhibit AEB-7, the expected market return is calculated using the constant growth DCF model discussed previously in my testimony for the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.27 percent and a weighted long-term growth

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[33] *Bloomberg Professional*, as of February 28, 2026.

[34] *Blue Chip Financial Forecasts,* Vol. 45, No. 3, February 27, 2026, at 2.

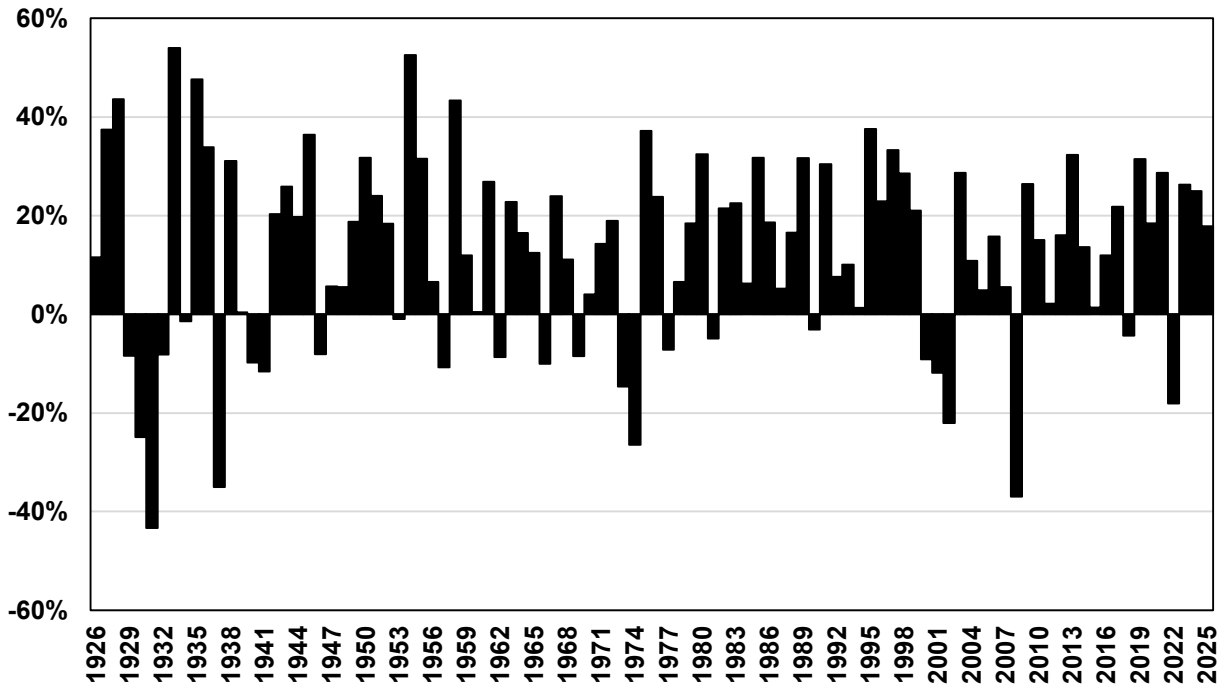
[35] *Blue Chip Financial Forecasts,* Vol. 44, No. 12, December 1, 2025, at 14.

rate of 11.65 percent, the estimated required market return for the S&P 500 Index as of February 28, 2026 is 12.99 percent.[36]

Q. How does the current expected market return compare to observed historical market returns?

A. As shown in Figure 6, given the range of annual equity returns that have been observed over the past century, the current expected market return is reasonable. In 53 out of the past 100 years (or 53.00 percent of observations), the realized equity market return was at least 12.99 percent or greater.

Figure 6: Realized U.S. Equity Market Returns (1926-2025)[37]



[36] The use of a projected market return to estimate the market risk premium is an approach that has also been relied upon by I&E in prior cases. *See, e.g.* Pennsylvania Public Utility Commission, Docket No: R-2020-3018929, Opinion and Order, June 17, 2021 at 155.

[37] Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook for 1926-2022 and from *S&P Capital IQ Pro* for 2023-2025.

Q. Do you consider another form of the CAPM in your analysis?

A. Yes. I also consider the results of an ECAPM analysis in estimating the cost of equity.[38] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required return of an individual security
β = the adjusted beta coefficient of an individual security
r_f = the risk-free rate of return
r_m = the required return on the market as a whole

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the cost of equity for companies with a beta less than 1.0 and overestimates the cost of equity for companies with a beta greater than 1.0.[39]

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[38] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., 2006, at 189.

[39] *Id*., at 191.

Consistent with the CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bond as the risk-free rate, forward-looking market return, and beta coefficients.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized below in Figure 7 and presented in more detail on PECO Exhibit AEB-5.

Figure 7: CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg.	Near-Term Forecast	Longer-Term Forecast
CAPM			
Current *Value Line* Beta	11.10%	11.09%	11.05%
Long-term Avg. *Value Line* Beta	11.20%	11.19%	11.16%
ECAPM			
Current *Value Line* Beta	11.57%	11.56%	11.54%
Long-term Avg. *Value Line* Beta	11.65%	11.64%	11.62%

C. Bond Yield Plus Risk Premium Analysis

Q. Please describe the BYRP approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Thus, risk premium approaches estimate the expected cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use historical authorized returns for electric and natural gas utilities across

the United States as the measure of the expected cost of equity at that time to determine the risk premium at that time.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. Both academic literature and market evidence indicate that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis presented on PECO Exhibit AEB-8 establishes that relationship using a regression of the risk premium as a function of U.S. Treasury bond yields. When the authorized ROEs serve as the measure of expected equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[40]

Q. What does your BYRP analysis reveal?

A. As shown in Figure 8, there is a strong negative relationship between risk premia and interest rates. To estimate that relationship, I have conducted a regression analysis using the following equation:

$$RP = a + b(T) \qquad [6]$$

Where:

[40] *See e.g.*, S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholders' Required Rates of Return," *Financial Management*, Spring 1986, at 66.

RP = risk premium (difference between authorized ROEs and the yield on 30-year U.S. Treasury bonds)

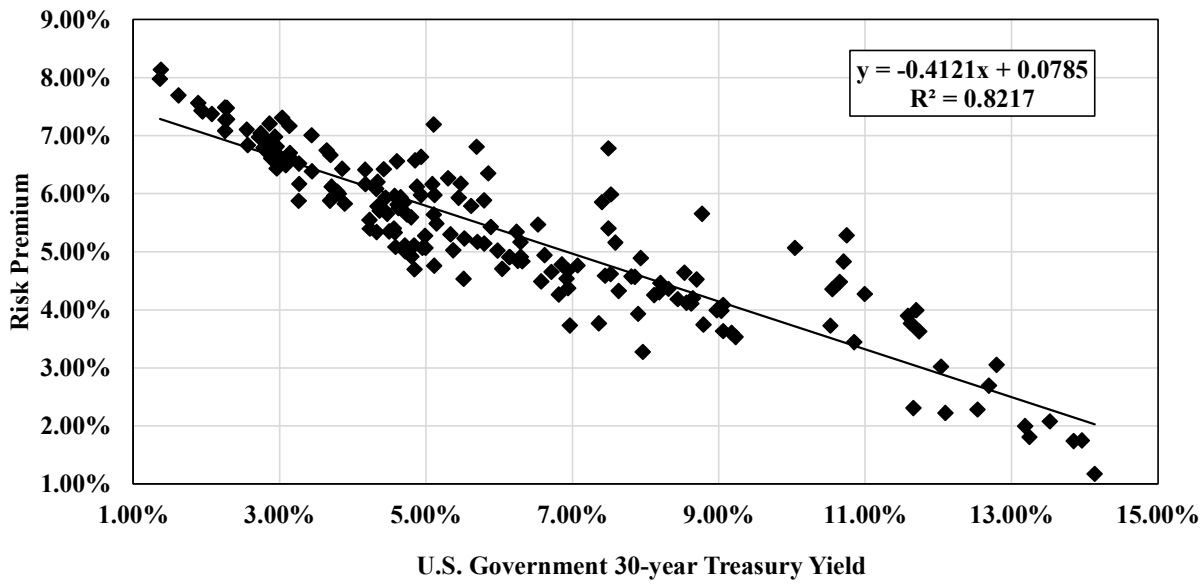
a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs is derived from all electric utility cases from January 1980 through February 2026 as reported by Regulatory Research Associates ("RRA"). The equation's coefficients are statistically significant at the 99.00 percent level.

Figure 8: Risk Premium Regression Analysis



Q. What are the results of your BYRP analysis?

A. The results of the BYRP analysis are shown in Figure 9, which are also presented in more detail on PECO Exhibit AEB-8.

Figure 9: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg.	Near-Term Forecast	Longer-Term Forecast
Bond Yield Risk Premium	10.66%	10.65%	10.55%

VII. REGULATORY AND BUSINESS RISKS

Q. Taken alone, do the results from the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A. No. These results provide only a range for the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Capital Expenditures

Q. Please summarize the Company's capital expenditure requirements.

A. As of December 31, 2025, the Company had net utility plant of approximately $11.13 billion, and the Company currently projects capital expenditures for 2026 through 2030 of approximately $9.8 billion.[41] Therefore, the Company's projected capital expenditures represent approximately 88 percent of its net utility plant as of December 31, 2025.

Q. How do the Company's projected capital expenditures compare to those of the proxy group companies?

A. As shown on PECO Exhibit AEB-9, I have calculated the ratio of projected capital expenditures to net utility plant for PECO and each of the companies in the proxy group. As shown therein, the Company's ratio of capital expenditures as a percentage of net utility plant is higher than the median of the proxy group companies (*i.e.*, 1.15 times), which, all else equal, indicates a risk level that is higher than that of the companies in the proxy group.

[41] Data provided by the Company.

Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[42]

[42] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through increasing capital expenditure requirements as a result of, among other things, the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure.[43]

Moody's views large capital programs as generally negative for credit because they create cost recovery risk and a drag on cash flow to debt metrics.[44] Moody's notes that the Company's capital spending will remain high over the next few years due to electric reliability investments.[45] Moody's states that because of the Company's large capital expenditure program for both its electric and natural gas operations that it expects PECO to produce negative cash flow.[46] Similar to Moody's, S&P also expects PECO's discretionary cash flow to remain negative due to its capital spending requirements, and lowered the Company's stand-alone credit profile to reflect the expected modest weakening of its forward-looking financial measures, noting that PECO will continue to depend on having consistent access to capital markets.[47]

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[43] S&P Global Ratings, "Industry Credit Outlook 2026, North American Regulated Utilities: Data center growth will support credit quality in 2026," January 14, 2026, at 3-4.

[44] Moody's Ratings, Credit Opinion, PECO Energy Company, October 28, 2025, at 5.

[45] *Id*.

[46] *Id*., at 7.

[47] S&P Global Ratings, "Exelon Corp. And Utility Subsidiary PECO Energy Upgraded to 'A-'; Outlook Stable," February 7, 2025, at 2.

Therefore, to the extent that the Company's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, it will face increased recovery risk and thus increased pressure on its credit metrics.

Q. Does the Company have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. Yes, PECO has a Distribution System Improvement Charge ("DSIC") that allows the utility to recover, on a quarterly basis, the costs associated with repair, replacement and improvement of its eligible infrastructure, up to five percent of its distribution revenue annually.[48] The presence of the DSIC is a positive aspect of Pennsylvania regulation, but such capital cost recovery mechanisms have become quite commonplace in utility regulation. As shown on PECO Exhibit AEB-10, 54 out of 77 (or approximately 70 percent) of the operating utility companies of the proxy group also have some form of capital cost recovery to address regulatory lag associated with capital expenditures between rate proceedings. Consequently, the presence of the DSIC, while a positive regulatory mechanism for the Company, does not reduce its risk vis-à-vis that of the proxy group.

Q. What is your conclusion regarding the regulatory environment in Pennsylvania as it relates to PECO's capital investment plan?

A. As noted, the Company's significant capital plan will require continued reasonable and cost-effective access to external capital for financing. Therefore, it is important that, as discussed in the following section, the constructive regulatory environment that has been

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[48] PECO Energy Company, Electric Service Tariff, Electric-Pa. P.U.C. No. 8, Effective January 1, 2026, Original Page No. 51, Section 4(A). Pursuant to the settlement in the Company's 2024 electric distribution rate proceeding, a new DSIC is not permitted to be filed until April 1, 2026. (Pennsylvania Public Utility Commission, Opinion and Order, Docket No. R-2024-3046931, *et al.*, PECO Energy Company – Electric Division, December 12, 2024, at 19.)

established by the Commission be maintained to ensure that the Company continues to be able to secure capital on favorable terms.

B. Regulatory Risk

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service to customers, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital on reasonable terms, and doing so balances the long-term interests of investors and customers. To achieve this balance, the Company must be able to finance its operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

In addition, equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Both Moody's and S&P consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[49]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "we assess regulatory advantage because the influence of the regulatory framework and regime is of critical importance. It defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[50] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2)

[49] Moody's Ratings, "Rating Methodology: Regulated Electric and Gas Utilities," August 6, 2024, at 2.

[50] S&P Global Ratings, "Sector-Specific Corporate Methodology," April 4, 2024, at 147.

tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[51]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[u]tility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the regulatory framework is a key determinant of the credit quality of a utility."[52] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[t]he regulatory framework is important because it provides the basis for decisions that affect utilities, including rate-setting as well as the consistency and predictability of regulatory decision-making."[53]

Q. Have you conducted any analysis of the risk associated with the regulatory framework in Pennsylvania relative to the jurisdictions in which the utility operating subsidiaries of the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Pennsylvania on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention for ratemaking (*i.e.,* forecast vs. historical test

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[51] *Id*.

[52] Moody's Ratings, "Rating Methodology: Regulated Electric and Gas Utilities," August 6, 2024, at 8.

[53] *Id*.

year); (2) use of rate design and/or other mechanisms that mitigate volumetric risk and stabilize revenue; (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown on PECO Exhibit AEB-10 and are summarized below:

Test Year Convention: The Company is proposing to use a fully forecast test year of calendar year 2027. Similarly, approximately half of the utility operating subsidiaries of the companies in the proxy group also use forecasted or partially forecasted test years. Forecasted test years have been relied on in many jurisdictions for years and produce cost estimates that are more reflective of future costs, which results in more accurate recovery of incurred costs and mitigates the regulatory lag associated with historical test years.

Revenue Stabilization/Volumetric Risk: The Company does not currently have protection against volumetric risk. Approximately 61 percent of the utility operating subsidiaries of the proxy group companies have some form of protection against volumetric risk either through revenue decoupling, formula-based rates, or straight fixed-variable rate design.

Capital Cost Recovery: As noted previously, PECO has quarterly capital cost recovery of a portion of its capital expenditures through the DSIC, and approximately 70 percent of the utility operating subsidiaries of the proxy group companies also have some form of capital cost recovery between rate cases in place.

Q. Have you developed any additional analyses to evaluate the regulatory environment in Pennsylvania as compared to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have conducted two additional analyses to compare the regulatory framework of Pennsylvania to the jurisdictions in which the companies in the proxy group operate. Specifically, I consider two different rankings: (1) the RRA ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q. How does RRA evaluate the regulatory environment in each jurisdiction?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies

that are regulated in each jurisdiction. RRA considers multiple factors that affect the regulatory process including state regulatory commission decisions, the impact of actions taken by the governor, the legislature, the courts, and consumer advocacy groups, and numerous factors regarding the ratemaking environment within the jurisdiction.[54]

Q. How do you use the RRA ratings to compare the regulatory jurisdictions of the proxy group companies with PECO's regulatory jurisdiction?

A. RRA assigns a ranking for each regulatory jurisdiction as "Above Average", "Average", or "Below Average", and then within each of those categories, a numeric ranking from 1 to 3. Thus, there are a total of nine RRA rankings, with the rankings for each jurisdiction ranging from "Above Average/1", which is considered the most supportive, to "Below Average/3," which is the least supportive. I have applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking (*i.e.*, a "1") and "Below Average/3" assigned the lowest ranking (*i.e.*, a "9").

Q. What are the results of this RRA jurisdictional ratings comparison?

A. As shown on PECO Exhibit AEB-11, the Pennsylvania jurisdictional ranking is "2.0" (*i.e.*, "Above Average/2") as compared to the proxy group average ranking of "4.85" (*i.e.*, between "Average/1" and "Average/2"), which means that Pennsylvania is considered by RRA to have a lower degree of regulatory risk as compared to the proxy group, on average.[55] S&P indicates that this ranking is based on a constructive regulatory climate that relies on forward test years and year end rate base that reduces regulatory lag.[56]

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[54] S&P Global Market Intelligence, "RRA State Regulatory Evaluations – Energy," July 2025.

[55] S&P Global Market Intelligence, "RRA State Regulatory Evaluations – Energy," December 29, 2025.

[56] S&P Global Market Intelligence, "RRA Regulatory Focus, State Regulatory Evaluations," December 9, 2019.

Q. How have you conducted your analysis of the S&P credit supportiveness rankings?

A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Most Credit Supportive" down to "Credit Supportive." My comparison of the credit supportiveness of PECO's regulatory jurisdiction to those in which the proxy companies operate is similar to the analysis of the RRA overall regulatory ranking just discussed. I assign a numerical ranking to each category, from "Most Credit Supportive" ("1") to "Credit Supportive" ("5").

Q. What are the results of this S&P credit supportiveness comparison?

A. As shown on PECO Exhibit AEB-12, similar to the RRA regulatory rankings, the Pennsylvania jurisdictional ranking is "2.00" (*i.e.*, "Highly Credit Supportive") as compared to the proxy group average ranking of "2.51" (*i.e.*, between "Highly Credit Supportive" and "Very Credit Supportive"), which means that Pennsylvania is considered to be moderately more credit supportive by S&P as compared to the proxy group, on average.

Q. What are your conclusions regarding the risks related to the Pennsylvania regulatory environment?

A. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the Company's significant projected capital expenditures relative to the proxy group, the RRA and S&P jurisdictional rankings for Pennsylvania, the Company's existing regulatory adjustment mechanisms relative to the proxy group, including not currently having some form of revenue stabilization to protect against

volumetric risk, it indicates that PECO's regulatory risk is approximately average when compared to the proxy group.

Q. Have you reviewed the Company's projected rate of return at current rates?

A. Yes. As discussed in Company witness Mr. Trzaska's direct testimony, and as shown on Exhibit MJT-1, the Company's return on common equity at present rates is 5.94 percent.

Q. Is a return on common equity of 5.94 percent reasonable?

A. No. A return on equity in this range is well below the equity returns authorized for regulated electric utilities, would be inadequate based on my cost of equity analyses and would not likely maintain the Company's credit metrics.

VIII. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as the Company. All else equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. What is PECO's proposed capital structure?

A. The Company proposes to establish a capital structure consisting of 53.40 percent common equity and 46.60 percent long-term debt.

Q. Have you analyzed whether this requested equity ratio was reasonable?

A. Yes. I have compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly traded to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is important to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company.

Specifically, I have calculated the average proportion of common equity, long-term debt, and preferred equity for the most recent eight quarters for each of the utility operating subsidiaries of the proxy group companies. As shown on PECO Exhibit AEB-13, the equity ratios for the utility operating subsidiaries of the proxy group range from 38.22 percent to 60.14 percent, with a mean of 52.46 percent and median of 53.29 percent. As such, PECO's proposed equity ratio of 53.40 percent is well within the range of equity ratios of the utility operating subsidiaries of the proxy group.

Q. Are there other factors to be considered in setting the Company's capital structure?

A. Yes, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, Moody's recently maintained its "stable" outlook for 2026 for the regulated gas and electric utilities sector based on the expectation of continued regulatory

support in "most states."[57] Moody's makes clear that constructive regulatory outcomes that promote timely cost recovery is the key factor in supporting utility credit quality as Moody's has identified that utilities could be exposed to a number of credit negative factors over the next 12 to 18 months. Specifically, Moody's noted the following factors: (1) macroeconomic factors are expected to be modestly credit negative due to upward pressure on natural gas prices and elevated inflation; and (2) increased power demand due to "the development of new data centers, electrification of transportation and buildings, manufacturing customers and underlying population growth" will increase power prices which when coupled with inflation and elevated capital spending increases utilities' exposure to affordability concerns.[58]

S&P states that after five years of downgrades outpacing upgrades, in 2025, upgrades outpaced downgrades and the percentage of companies with a negative outlook declined, which S&P noted pointed to a "more stable environment for credit quality in 2026".[59] However, S&P expects the industry to have increased cash flow deficits as a result of significant capital spending, which must be funded with both debt and equity to maintain credit quality.[60] Therefore, S&P notes that the utility industry will need ongoing access to capital markets to fund the significant capital expenditures. S&P also notes that credit quality will depend on the ability of utilities to manage regulatory risk and achieve fair rate case orders. Finally, while S&P's base case results in a stable outlook for the

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57 Moody's Ratings, Outlook, "Outlook Stable; supportive regulation to offset modestly negative macro factors," October 31, 2025.

58 *Id*.

59 S&P Global Ratings, Industry Credit Outlook 2026, "North American Regulated Utilities: Data center growth will support credit quality in 2026," January 14, 2026.

60 *Id*.

utility sector, S&P states that about 40 percent of the industry has "minimal financial cushion" from the downgrade threshold and therefore would have limited ability to absorb any unexpected events outside of what is assumed in S&P's base case.[61]

Fitch Ratings ("Fitch") maintains a "neutral" outlook for the utility industry in 2026 noting that the stable outlook was supported by growth in sales related to data centers and a "generally benign" regulatory environment for utilities.[62] However, while Fitch views load growth as a "positive development" because the growth is related to data centers, it raises longer-term uncertainty related to "rate design, customer concentration, and technology risks."[63] Further, Fitch states that capital expenditures for the industry will continue to "set records" in order to meet the growing demand and to enhance reliability and modernize. The record capital expenditures will require a balanced regulatory environment to facilitate cost recovery in a credit supportive manner. Fitch also noted that extreme weather events such as wildfires and hurricanes continue to present significant event risk for electric utilities.[64]

The continued concerns of the credit rating agencies over increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the Company in the context of this proceeding. A reasonable capital structure is key to maintaining supportive cash flow.

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61 *Id.*

62 Fitch Ratings, "North American Utilities & Power Outlook 2026," December 9, 2025, at 1.

63 *Id.*

64 *Id.*

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. Because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. Consequently, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously.

IX. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for PECO?

A. Figure 10 summarizes the results of the analyses that I have conducted and described herein. Based on these results, the qualitative analyses presented in my direct testimony, the business and financial risks of PECO as compared to the proxy group, and current and prospective conditions in capital markets, the Company's requested ROE of 10.95 percent is appropriate.

Figure 10: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results			
30-Day Avg. Stock Price	9.51%	10.80%	11.95%
90-Day Avg. Stock Price	9.64%	10.94%	12.09%
180-Day Avg. Stock Price	9.77%	11.07%	12.22%
Average	9.64%	10.94%	12.09%
Median Results			
30-Day Avg. Stock Price	9.68%	10.53%	11.41%
90-Day Avg. Stock Price	9.78%	10.63%	11.55%
180-Day Avg. Stock Price	9.84%	10.72%	11.73%
Average	9.77%	10.62%	11.56%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg.	Near-Term Forecast	Longer-Term Forecast
CAPM			
Current *Value Line* Beta	11.10%	11.09%	11.05%
Long-term Avg. *Value Line* Beta	11.20%	11.19%	11.16%
ECAPM			
Current *Value Line* Beta	11.57%	11.56%	11.54%
Long-term Avg. *Value Line* Beta	11.65%	11.64%	11.62%
Bond Yield Risk Premium	10.66%	10.65%	10.55%

Q. What is your conclusion with respect to PECO's proposed capital structure?

A. PECO's proposal to establish a capital structure consisting of 53.40 percent common equity is reasonable when compared to the actual capital structures of the operating utility subsidiaries of the proxy group companies.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Ann E. Bulkley, hereby state that I am a Principal at The Brattle Group; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 7 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.



Dated: March 30, 2026

Ann E. Bulkley

PECO Exhibit
AEB-1 through AEB-13

Ann E. Bulkley

PRINCIPAL

Boston 508.981.0866 Ann.Bulkley@brattle.com

With more than 30 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in more than 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

Brattle

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power Company	6/25	Tucson Electric Power Company	Docket No. G-01933A-25-0103	Return on Equity
UNS Gas	11/24	UNS Gas	Docket No. G-04204A-24-0237	Return on Equity
Southwest Gas Corporation	02/24	Southwest Gas Corporation	Docket No. G-01551A-23-0341	Return on Equity
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
California Public Utilities Commission				
Pacific Gas & Electric Company	03/25	Pacific Gas & Electric Company	25-03-010	Return on Equity
PacifiCorp, d/b/a Pacific Power	05/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	12/25	Public Service Company of Colorado	Docket No. 25AL-0499G	Return on Equity
Public Service Company of Colorado	11/25	Public Service Company of Colorado	Docket No. 25AL-0494E	Return on Equity
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	11/24	United Illuminating	Docket No. 24-10-04	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Northern Natural Gas Company	07/25	Northern Natural Gas Company	Docket No. RP25-___	Return on Equity
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	05/25	Intermountain Gas Co	C-INT-G-25-02	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/24	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-24-04	Return on Equity
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/26	Peoples Gas Light & Coke Company	D-26-0065	Return on Equity
North Shore Gas Company	01/26	North Shore Gas Company	D-26-0066	Return on Equity
Illinois American Water	01/24	Illinois American Water	Docket No. 24-0097	Return on Equity
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana Utility Regulatory Commission				
Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	02/24	Ohio Valley Gas Corporation and Ohio Valley Gas, Inc.	Cause No. 46011	Return on Equity
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	02/25	MidAmerican Energy Company	Docket No. RPU-2025-0001	Return on Equity
Iowa-American Water Company	04/24	Iowa-American Water Company	Docket No. RPU-2024-000_	Return on Equity
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	01/25	Evergy Kansas	Docket No. 25-EKCE-294-RTS	Return on Equity
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	04/25	Kentucky American Water Company	Docket No. 2025-____	Return on Equity
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	09/25	Central Maine Power	Docket No. 2025-____	Return on Equity
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Boston Gas Company	01/26	Boston Gas Company	DPU 26-50	Return on Equity
Berkshire Gas Company	11/25	Berkshire Gas Company	DPU 25-170	Return on Equity
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Consumers Energy	6/25	Consumers Energy	C-U-21870	Return on Equity
Consumers Energy	12/24	Consumers Energy	C-U-21806	Return on Equity
Upper Michigan Energy Resources Corporation	05/24	Upper Michigan Energy Resources Corporation	Case No. U-21541	Return on Equity
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Otter Tail Power Company	10/25	Otter Tail Power Company	E017/GR-25-359	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Evergy Metro Inc.	02/26	Evergy Metro Inc.	C-ER-2026-0143	Return on Equity
Ameren Missouri	09/24	Ameren Missouri	File No. GR-2024-0369	Return on Equity
Missouri American Water Company	07/24	Missouri American Water Company	WR-2024-0320	Return on Equity
Ameren Missouri	06/24	Ameren Missouri	File No. ER-2024-0319	Return on Equity
Evergy Missouri West	02/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	01/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	01/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	9/25	Montana-Dakota Utilities Co.	D2025-09-072	Return on Equity
Montana-Dakota Utilities Co.	7/24	Montana-Dakota Utilities Co.	D2024-05-061	Return on Equity
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
Public Utilities Commission of Nevada				
Nevada Power Company d/b/a NV Energy	02/25	Nevada Power Company d/b/a NV Energy	25-02016	Return on Equity
Sierra Pacific Power Company d/b/a NV Energy	02/24	Sierra Pacific Power Company d/b/a NV Energy	24-02026	Return on Equity
Nevada Power Company d/b/a NV Energy	06/23	Nevada Power Company d/b/a NV Energy	23-06007	Return on Equity
Nevada Power Company d/b/a NV Energy	03/23	Nevada Power Company d/b/a NV Energy	22-03028	Merger benefits
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
South Jersey Gas Company	11/25	South Jersey Gas Company	D-GR25110627	Return on Equity
New Jersey American Water Company, Inc.	02/24	New Jersey American Water Company, Inc.	WR2401056	Return on Equity
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	12/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	06/25	New York State Electric and Gas Company Rochester Gas and Electric	25-E-0375 25-G-0378 25-E-0379 25-G-0380	Return on Equity
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-342	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-341	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
Cascade Natural Gas Corporation	11/25	Cascade Natural Gas Corporation	UG 525	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/24	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-433	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/25	Pennsylvania-American Water Company	Docket No. R-2025-3057983 (water) Docket No. R-2025-3058051 (wastewater)	Return on Equity
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Co.	06/25	Otter Tail Power Co.	D-EL25-022	Return on Equity
Montana-Dakota Utilities Co.	10/23	Montana-Dakota Utilities Co.	Docket No. EL23-020	Return on Equity
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Tennessee Public Utility Commission				
Tennessee American Water Company	04/24	Tennessee American Water Company	Docket No.24-00032	Return on Equity
Texas Public Utility Commission				
Sharyland Utilities, L.L.C.	05/25	Sharyland Utilities, L.L.C.	Docket No. 57994	Return on Equity
Electric Transmission Texas LLC	02/25	Electric Transmission Texas LLC	Docket No. 57518	Return on Equity
CenterPoint Energy Houston	03/24	CenterPoint Energy Houston	D-56211	Return on Equity
AEP Texas	02/24	AEP Texas	D-56165	Return on Equity
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	06/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 24-035-04	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/25	Virginia American Water Company, Inc.	Docket No. PUR-2025-00185	Return on Equity
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	03/24	Cascade Natural Gas Corporation	Docket No. UG-240008	Return on Equity
Puget Sound Energy Inc.	02/24	Puget Sound Energy Inc.	Docket No. UE-240004 UG-240005	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/25	West Virginia American Water Company	Case No. 25-____-W-42T	Return on Equity
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	04/24	Wisconsin Power and Light	Docket No. 6680-UR-128	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/24	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-111	Return on Equity
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wyoming Public Service Commission				
Montana-Dakota Utilities Co.	06/25	Montana-Dakota Utilities Co.	Docket No. 20004-174-ER-25	Return on Equity
Montana-Dakota Utilities Co.	10/24	Montana-Dakota Utilities Co.	Docket No. 30013-415-GR-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	08/24	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-671-ER-24	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results			
30-Day Avg. Stock Price	9.51%	10.80%	11.95%
90-Day Avg. Stock Price	9.64%	10.94%	12.09%
180-Day Avg. Stock Price	9.77%	11.07%	12.22%
Average	9.64%	10.94%	12.09%
Median Results			
30-Day Avg. Stock Price	9.68%	10.53%	11.41%
90-Day Avg. Stock Price	9.78%	10.63%	11.55%
180-Day Avg. Stock Price	9.84%	10.72%	11.73%
Average	9.77%	10.62%	11.56%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg.	Near-Term Forecast	Longer-Term Forecast
CAPM			
Current *Value Line* Beta	11.10%	11.09%	11.05%
Long-term Avg. *Value Line* Beta	11.20%	11.19%	11.16%
ECAPM			
Current *Value Line* Beta	11.57%	11.56%	11.54%
Long-term Avg. *Value Line* Beta	11.65%	11.64%	11.62%
Bond Yield Risk Premium	10.66%	10.65%	10.55%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Dividends	S&P Credit Rating Between AAA and BBB-	Positive Growth Rates from at least two sources (*S&P Capital IQ*, *Value Line*, and/or *Zacks*)	% Regulated Elec. Operating Income of Total Operating Income > 70%	Announced Merger
Alliant Energy Corporation	LNT	Yes	BBB+	Yes	86.94%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	84.42%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	99.09%	No
Avista Corporation	AVA	Yes	BBB	Yes	74.40%	No
Dominion Resources, Inc.	D	Yes	BBB+	Yes	96.93%	No
Edison International	EIX	Yes	BBB-	Yes	100.67%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	96.44%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	100.00%	No
FirstEnergy Corporation	FE	Yes	BBB+	Yes	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	99.99%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	83.75%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	100.00%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	100.00%	No
PPL Corporation	PPL	Yes	A-	Yes	94.19%	No
Southern Company	SO	Yes	A-	Yes	77.26%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	85.62%	No

Notes:

[1] Bloomberg Professional
[2] Bloomberg Professional
[3] S&P Capital IQ, Value Line Investment Survey, and Zacks
[4] Form 10-K's for 2024, 2023, and 2022
[5] S&P Capital IQ Pro Financial News Releases

CONSTANT GROWTH DCF
30-DAY AVERAGE STOCK PRICES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
						Projected EPS Growth Rates				Cost of Equity		
Company	Ticker	Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line	Zacks	S&P Capital IQ	Average	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$68.21	3.14%	3.25%	6.00%	7.20%	7.69%	6.96%	9.23%	10.21%	10.95%
Ameren Corporation	AEE	$2.84	$106.45	2.67%	2.77%	6.50%	9.30%	8.09%	7.96%	9.25%	10.74%	12.09%
American Electric Power Company, I	AEP	$3.80	$123.02	3.09%	3.20%	6.50%	6.70%	8.30%	7.17%	9.69%	10.37%	11.52%
Avista Corporation	AVA	$1.97	$40.90	4.82%	4.97%	6.50%	7.10%	6.01%	6.54%	10.98%	11.51%	12.09%
Dominion Resources, Inc.	D	$2.67	$61.93	4.31%	4.48%	6.50%	10.30%	6.91%	7.90%	10.95%	12.38%	14.83%
Edison International	EIX	$3.51	$66.29	5.29%	5.50%	6.50%	10.10%	6.77%	7.79%	11.97%	13.29%	15.66%
Entergy Corporation	ETR	$2.56	$99.07	2.58%	2.69%	3.00%	11.50%	11.20%	8.57%	5.62%	11.26%	14.23%
Evergy, Inc.	EVRG	$2.78	$78.68	3.53%	3.65%	7.50%	5.90%	7.22%	6.87%	9.54%	10.53%	11.17%
FirstEnergy Corporation	FE	$1.78	$47.96	3.71%	3.83%	5.00%	6.50%	7.45%	6.32%	8.80%	10.15%	11.30%
IDACORP, Inc.	IDA	$3.52	$136.59	2.58%	2.67%	6.00%	8.00%	8.34%	7.45%	8.65%	10.12%	11.02%
NextEra Energy, Inc.	NEE	$2.49	$88.71	2.81%	2.92%	8.00%	8.10%	7.06%	7.72%	9.96%	10.64%	11.02%
OGE Energy Corporation	OGE	$1.70	$45.14	3.77%	3.88%	6.50%	5.80%	6.43%	6.24%	9.68%	10.13%	10.39%
Pinnacle West Capital Corporation	PNW	$3.64	$95.21	3.82%	3.93%	5.00%	3.60%	7.67%	5.42%	7.49%	9.35%	11.64%
PPL Corporation	PPL	$1.09	$36.74	2.97%	3.08%	7.50%	7.30%	7.56%	7.45%	10.38%	10.53%	10.64%
Southern Company	SO	$2.96	$90.70	3.26%	3.38%	6.50%	7.20%	7.36%	7.02%	9.87%	10.40%	10.74%
Xcel Energy Inc.	XEL	$2.28	$78.21	2.92%	3.03%	7.00%	8.90%	8.70%	8.20%	10.02%	11.23%	11.95%
Mean										9.51%	10.80%	11.95%
Median										9.68%	10.53%	11.41%

Notes:
[1] Bloomberg Professional as of February 28 2026
[2] Bloomberg Professional 30-day average as of February 28 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ Pro
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CONSTANT GROWTH DCF
90-DAY AVERAGE STOCK PRICES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
						Projected EPS Growth Rates				Cost of Equity		
Company	Ticker	Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line	Zacks	S&P Capital IQ	Average	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$66.75	3.21%	3.32%	6.00%	7.20%	7.69%	6.96%	9.30%	10.28%	11.02%
Ameren Corporation	AEE	$2.84	$103.11	2.75%	2.86%	6.50%	9.30%	8.09%	7.96%	9.34%	10.83%	12.18%
American Electric Power Company, I	AEP	$3.80	$118.97	3.19%	3.31%	6.50%	6.70%	8.30%	7.17%	9.80%	10.48%	11.63%
Avista Corporation	AVA	$1.97	$39.47	4.99%	5.15%	6.50%	7.10%	6.01%	6.54%	11.16%	11.69%	12.27%
Dominion Resources, Inc.	D	$2.67	$59.86	4.46%	4.64%	6.50%	10.30%	6.91%	7.90%	11.11%	12.54%	14.99%
Edison International	EIX	$3.51	$60.51	5.80%	6.03%	6.50%	10.10%	6.77%	7.79%	12.49%	13.82%	16.19%
Entergy Corporation	ETR	$2.56	$95.42	2.68%	2.80%	3.00%	11.50%	11.20%	8.57%	5.72%	11.36%	14.34%
Evergy, Inc.	EVRG	$2.78	$76.13	3.65%	3.78%	7.50%	5.90%	7.22%	6.87%	9.66%	10.65%	11.29%
FirstEnergy Corporation	FE	$1.78	$46.04	3.87%	3.99%	5.00%	6.50%	7.45%	6.32%	8.96%	10.31%	11.46%
IDACORP, Inc.	IDA	$3.52	$130.81	2.69%	2.79%	6.00%	8.00%	8.34%	7.45%	8.77%	10.24%	11.14%
NextEra Energy, Inc.	NEE	$2.49	$84.04	2.97%	3.08%	8.00%	8.10%	7.06%	7.72%	10.13%	10.80%	11.19%
OGE Energy Corporation	OGE	$1.70	$44.13	3.85%	3.97%	6.50%	5.80%	6.43%	6.24%	9.76%	10.22%	10.48%
Pinnacle West Capital Corporation	PNW	$3.64	$90.46	4.02%	4.13%	5.00%	3.60%	7.67%	5.42%	7.70%	9.56%	11.85%
PPL Corporation	PPL	$1.09	$35.88	3.04%	3.15%	7.50%	7.30%	7.56%	7.45%	10.45%	10.60%	10.71%
Southern Company	SO	$2.96	$89.25	3.32%	3.43%	6.50%	7.20%	7.36%	7.02%	9.92%	10.45%	10.79%
Xcel Energy Inc.	XEL	$2.28	$77.58	2.94%	3.06%	7.00%	8.90%	8.70%	8.20%	10.04%	11.26%	11.97%
Mean										9.64%	10.94%	12.09%
Median										9.78%	10.63%	11.55%

Notes:
[1] Bloomberg Professional as of February 28 2026
[2] Bloomberg Professional 90-day average as of February 28 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ Pro
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CONSTANT GROWTH DCF
180-DAY AVERAGE STOCK PRICES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
						Projected EPS Growth Rates				Cost of Equity		
Company	Ticker	Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line	Zacks	S&P Capital IQ	Average	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.14	$65.00	3.29%	3.41%	6.00%	7.20%	7.69%	6.96%	9.39%	10.37%	11.11%
Ameren Corporation	AEE	$2.84	$100.87	2.82%	2.93%	6.50%	9.30%	8.09%	7.96%	9.41%	10.89%	12.25%
American Electric Power Company, I	AEP	$3.80	$113.15	3.36%	3.48%	6.50%	6.70%	8.30%	7.17%	9.97%	10.65%	11.80%
Avista Corporation	AVA	$1.97	$37.81	5.21%	5.38%	6.50%	7.10%	6.01%	6.54%	11.38%	11.92%	12.50%
Dominion Resources, Inc.	D	$2.67	$58.62	4.56%	4.74%	6.50%	10.30%	6.91%	7.90%	11.20%	12.64%	15.09%
Edison International	EIX	$3.51	$56.20	6.25%	6.49%	6.50%	10.10%	6.77%	7.79%	12.95%	14.28%	16.66%
Entergy Corporation	ETR	$2.56	$91.12	2.81%	2.93%	3.00%	11.50%	11.20%	8.57%	5.85%	11.50%	14.47%
Evergy, Inc.	EVRG	$2.78	$73.39	3.79%	3.92%	7.50%	5.90%	7.22%	6.87%	9.80%	10.79%	11.43%
FirstEnergy Corporation	FE	$1.78	$43.97	4.05%	4.18%	5.00%	6.50%	7.45%	6.32%	9.15%	10.49%	11.65%
IDACORP, Inc.	IDA	$3.52	$126.39	2.78%	2.89%	6.00%	8.00%	8.34%	7.45%	8.87%	10.33%	11.24%
NextEra Energy, Inc.	NEE	$2.49	$78.51	3.18%	3.30%	8.00%	8.10%	7.06%	7.72%	10.34%	11.02%	11.40%
OGE Energy Corporation	OGE	$1.70	$44.06	3.86%	3.98%	6.50%	5.80%	6.43%	6.24%	9.77%	10.22%	10.48%
Pinnacle West Capital Corporation	PNW	$3.64	$89.23	4.08%	4.19%	5.00%	3.60%	7.67%	5.42%	7.75%	9.61%	11.91%
PPL Corporation	PPL	$1.09	$35.61	3.06%	3.18%	7.50%	7.30%	7.56%	7.45%	10.47%	10.63%	10.74%
Southern Company	SO	$2.96	$90.39	3.27%	3.39%	6.50%	7.20%	7.36%	7.02%	9.88%	10.41%	10.75%
Xcel Energy Inc.	XEL	$2.28	$74.75	3.05%	3.18%	7.00%	8.90%	8.70%	8.20%	10.16%	11.37%	12.09%
Mean										9.77%	11.07%	12.22%
Median										9.84%	10.72%	11.73%

Notes:
[1] Bloomberg Professional as of February 28 2026
[2] Bloomberg Professional 180-day average as of February 28 2026
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] S&P Capital IQ Pro
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Ameren Corporation	AEE	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
American Electric Power Company, Inc.	AEP	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Avista Corporation	AVA	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Dominion Resources, Inc.	D	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Edison International	EIX	4.79%	0.90	12.99%	8.20%	12.17%	12.38%
Entergy Corporation	ETR	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
Evergy, Inc.	EVRG	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
FirstEnergy Corporation	FE	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
IDACORP, Inc.	IDA	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
NextEra Energy, Inc.	NEE	4.79%	0.90	12.99%	8.20%	12.17%	12.38%
OGE Energy Corporation	OGE	4.79%	0.85	12.99%	8.20%	11.76%	12.07%
Pinnacle West Capital Corporation	PNW	4.79%	0.75	12.99%	8.20%	10.94%	11.45%
PPL Corporation	PPL	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Southern Company	SO	4.79%	0.65	12.99%	8.20%	10.12%	10.84%
Xcel Energy Inc.	XEL	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Mean						11.10%	11.57%
Median						10.94%	11.45%

Notes:

[1] Bloomberg Professional 30-day average as of February 28 2026

[2] Value Line

[3] PECO Exhibit AEB-7

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Ameren Corporation	AEE	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
American Electric Power Company, Inc.	AEP	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Avista Corporation	AVA	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Dominion Resources, Inc.	D	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Edison International	EIX	4.76%	0.90	12.99%	8.23%	12.17%	12.38%
Entergy Corporation	ETR	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
Evergy, Inc.	EVRG	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
FirstEnergy Corporation	FE	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
IDACORP, Inc.	IDA	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
NextEra Energy, Inc.	NEE	4.76%	0.90	12.99%	8.23%	12.17%	12.38%
OGE Energy Corporation	OGE	4.76%	0.85	12.99%	8.23%	11.76%	12.07%
Pinnacle West Capital Corporation	PNW	4.76%	0.75	12.99%	8.23%	10.93%	11.45%
PPL Corporation	PPL	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Southern Company	SO	4.76%	0.65	12.99%	8.23%	10.11%	10.83%
Xcel Energy Inc.	XEL	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Mean						11.09%	11.56%
Median						10.93%	11.45%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026, at 2

[2] Value Line

[3] PECO Exhibit AEB-7

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Longer-Term Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Ameren Corporation	AEE	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
American Electric Power Company, Inc.	AEP	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Avista Corporation	AVA	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Dominion Resources, Inc.	D	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Edison International	EIX	4.60%	0.90	12.99%	8.39%	12.15%	12.36%
Entergy Corporation	ETR	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
Evergy, Inc.	EVRG	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
FirstEnergy Corporation	FE	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
IDACORP, Inc.	IDA	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
NextEra Energy, Inc.	NEE	4.60%	0.90	12.99%	8.39%	12.15%	12.36%
OGE Energy Corporation	OGE	4.60%	0.85	12.99%	8.39%	11.73%	12.05%
Pinnacle West Capital Corporation	PNW	4.60%	0.75	12.99%	8.39%	10.89%	11.42%
PPL Corporation	PPL	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Southern Company	SO	4.60%	0.65	12.99%	8.39%	10.06%	10.79%
Xcel Energy Inc.	XEL	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Mean						11.05%	11.54%
Median						10.89%	11.42%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14

[2] Value Line

[3] PECO Exhibit AEB-7

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.79%	0.78	12.99%	8.20%	11.16%	11.62%
Ameren Corporation	AEE	4.79%	0.75	12.99%	8.20%	10.97%	11.48%
American Electric Power Company, Inc.	AEP	4.79%	0.70	12.99%	8.20%	10.50%	11.12%
Avista Corporation	AVA	4.79%	0.80	12.99%	8.20%	11.35%	11.76%
Dominion Resources, Inc.	D	4.79%	0.74	12.99%	8.20%	10.85%	11.38%
Edison International	EIX	4.79%	0.80	12.99%	8.20%	11.38%	11.79%
Entergy Corporation	ETR	4.79%	0.78	12.99%	8.20%	11.19%	11.64%
Evergy, Inc.	EVRG	4.79%	0.91	12.99%	8.20%	12.24%	12.43%
FirstEnergy Corporation	FE	4.79%	0.76	12.99%	8.20%	11.01%	11.50%
IDACORP, Inc.	IDA	4.79%	0.74	12.99%	8.20%	10.88%	11.41%
NextEra Energy, Inc.	NEE	4.79%	0.79	12.99%	8.20%	11.26%	11.69%
OGE Energy Corporation	OGE	4.79%	0.95	12.99%	8.20%	12.55%	12.66%
Pinnacle West Capital Corporation	PNW	4.79%	0.77	12.99%	8.20%	11.10%	11.57%
PPL Corporation	PPL	4.79%	0.85	12.99%	8.20%	11.79%	12.09%
Southern Company	SO	4.79%	0.70	12.99%	8.20%	10.53%	11.15%
Xcel Energy Inc.	XEL	4.79%	0.69	12.99%	8.20%	10.44%	11.08%
Mean						11.20%	11.65%
Median						11.13%	11.60%

Notes:

[1] Bloomberg Professional 30-day average as of February 28 2026

[2] PECO Exhibit AEB-6

[3] PECO Exhibit AEB-7

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.76%	0.78	12.99%	8.23%	11.16%	11.62%
Ameren Corporation	AEE	4.76%	0.75	12.99%	8.23%	10.97%	11.47%
American Electric Power Company, Inc.	AEP	4.76%	0.70	12.99%	8.23%	10.49%	11.12%
Avista Corporation	AVA	4.76%	0.80	12.99%	8.23%	11.35%	11.76%
Dominion Resources, Inc.	D	4.76%	0.74	12.99%	8.23%	10.84%	11.38%
Edison International	EIX	4.76%	0.80	12.99%	8.23%	11.38%	11.78%
Entergy Corporation	ETR	4.76%	0.78	12.99%	8.23%	11.19%	11.64%
Evergy, Inc.	EVRG	4.76%	0.91	12.99%	8.23%	12.24%	12.43%
FirstEnergy Corporation	FE	4.76%	0.76	12.99%	8.23%	11.00%	11.50%
IDACORP, Inc.	IDA	4.76%	0.74	12.99%	8.23%	10.87%	11.40%
NextEra Energy, Inc.	NEE	4.76%	0.79	12.99%	8.23%	11.25%	11.69%
OGE Energy Corporation	OGE	4.76%	0.95	12.99%	8.23%	12.55%	12.66%
Pinnacle West Capital Corporation	PNW	4.76%	0.77	12.99%	8.23%	11.09%	11.57%
PPL Corporation	PPL	4.76%	0.85	12.99%	8.23%	11.79%	12.09%
Southern Company	SO	4.76%	0.70	12.99%	8.23%	10.52%	11.14%
Xcel Energy Inc.	XEL	4.76%	0.69	12.99%	8.23%	10.43%	11.07%
Mean						11.19%	11.64%
Median						11.12%	11.59%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026, at 2
[2] PECO Exhibit AEB-6
[3] PECO Exhibit AEB-7
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

Company	Ticker	[1] Longer-Term Projected 30-year U.S. Treasury bond yield (2027 - 2031)	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Alliant Energy Corporation	LNT	4.60%	0.78	12.99%	8.39%	11.12%	11.59%
Ameren Corporation	AEE	4.60%	0.75	12.99%	8.39%	10.93%	11.44%
American Electric Power Company, Inc.	AEP	4.60%	0.70	12.99%	8.39%	10.44%	11.08%
Avista Corporation	AVA	4.60%	0.80	12.99%	8.39%	11.31%	11.73%
Dominion Resources, Inc.	D	4.60%	0.74	12.99%	8.39%	10.80%	11.35%
Edison International	EIX	4.60%	0.80	12.99%	8.39%	11.35%	11.76%
Entergy Corporation	ETR	4.60%	0.78	12.99%	8.39%	11.15%	11.61%
Evergy, Inc.	EVRG	4.60%	0.91	12.99%	8.39%	12.22%	12.42%
FirstEnergy Corporation	FE	4.60%	0.76	12.99%	8.39%	10.96%	11.47%
IDACORP, Inc.	IDA	4.60%	0.74	12.99%	8.39%	10.83%	11.37%
NextEra Energy, Inc.	NEE	4.60%	0.79	12.99%	8.39%	11.22%	11.66%
OGE Energy Corporation	OGE	4.60%	0.95	12.99%	8.39%	12.54%	12.65%
Pinnacle West Capital Corporation	PNW	4.60%	0.77	12.99%	8.39%	11.06%	11.54%
PPL Corporation	PPL	4.60%	0.85	12.99%	8.39%	11.77%	12.07%
Southern Company	SO	4.60%	0.70	12.99%	8.39%	10.47%	11.10%
Xcel Energy Inc.	XEL	4.60%	0.69	12.99%	8.39%	10.38%	11.03%
Mean						11.16%	11.62%
Median						11.09%	11.56%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14

[2] PECO Exhibit AEB-6

[3] PECO Exhibit AEB-7

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] 12/31/2023	[12] 12/31/2024	[13] 12/31/2025	[14] Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.80	0.78
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.90	0.75	0.75
American Electric Power Company	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.80	0.70	0.70
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.95	0.70	0.80
Dominion Resources, Inc.	D	0.70	0.70	0.70	0.65	0.65	0.60	0.55	0.80	0.85	0.85	0.85	0.90	0.80	0.74
Edison International	EIX	0.80	0.75	0.70	0.65	0.65	0.55	0.55	0.95	0.95	0.95	1.00	1.05	0.90	0.80
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.95	1.00	0.75	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.75	0.91
FirstEnergy Corporation	FE	0.75	0.70	0.70	0.65	0.70	0.60	0.65	0.85	0.85	0.85	0.90	0.90	0.75	0.76
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.85	0.85	0.65	0.74
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	1.00	1.05	0.90	0.79
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	1.10	0.85	0.95
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.95	0.95	0.75	0.77
PPL Corporation	PPL	0.65	0.60	0.70	0.70	0.75	0.70	0.70	1.15	1.10	1.05	1.10	1.10	0.80	0.85
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.95	0.95	0.65	0.70
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.85	0.85	0.70	0.69
Mean		0.72	0.72	0.74	0.68	0.69	0.59	0.58	0.91	0.90	0.89	0.93	0.95		0.78

Notes:

[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.
[13] Value Line, Dated December 26, 2025

MARKET RETURN DERIVED FROM S&P 500 INDEX

[1] Estimated Weighted Average Dividend Yield	1.27%
[2] Estimate of the S&P 500 Growth Rate	11.65%
[3] S&P 500 Estimated Required Market Return	12.99%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Agilent Technologies Inc	A	282.84	121.38	34,331.08	0.09%	0.84%	0.00%	7.99%	0.01%
Apple Inc	AAPL	14,681.14	264.18	3,878,463.57	10.48%	0.39%	0.04%	13.33%	1.40%
AbbVie Inc	ABBV	1,768.17	232.08	410,356.66	1.11%	2.98%	0.03%	19.68%	0.22%
Airbnb Inc	ABNB	423.57	135.11	57,228.99	0.15%			16.62%	0.03%
Abbott Laboratories	ABT	1,737.68	116.35	202,179.40	0.55%	2.17%	0.01%	10.11%	0.06%
Arch Capital Group Ltd	ACGL	355.80	100.15	35,633.70	0.10%			2.64%	0.00%
Accenture PLC	ACN	615.31	208.72	128,426.83		3.12%			
Adobe Inc	ADBE	410.50	262.41	107,719.31	0.29%			13.73%	0.04%
Analog Devices Inc	ADI	488.20	354.68	173,156.06		1.24%		22.33%	
Archer-Daniels-Midland Co	ADM	481.20	69.04	33,222.18	0.09%	3.01%	0.00%	18.91%	0.02%
Automatic Data Processing Inc	ADP	402.64	214.36	86,310.85		3.17%			
Autodesk Inc	ADSK	212.00	245.87	52,124.44				21.63%	
Ameren Corp	AEE	276.42	113.28	31,313.37	0.08%	2.65%	0.00%	8.44%	0.01%
American Electric Power Co Inc	AEP	540.86	133.82	72,378.08	0.20%	2.84%	0.01%	7.91%	0.02%
AES Corp/The	AES	712.12	17.28	12,305.45	0.03%	4.07%	0.00%	11.17%	0.00%
Aflac Inc	AFL	516.37	112.93	58,313.60		2.16%			
American International Group Inc	AIG	536.56	80.49	43,187.69		2.24%			
Assurant Inc	AIZ	49.70	229.59	11,410.57		1.53%			
Arthur J Gallagher & Co	AJG	257.10	228.20	58,670.22		1.23%			
Akamai Technologies Inc	AKAM	144.89	98.39	14,255.54	0.04%			5.96%	0.00%
Albemarle Corp	ALB	117.85	178.67	21,055.76		0.91%		175.50%	
Align Technology Inc	ALGN	71.28	190.10	13,550.73				-2.94%	
Allstate Corp/The	ALL	259.54	213.44	55,395.36		2.02%		-1.75%	
Allegion plc	ALLE	86.15	161.15	13,882.34	0.04%	1.37%	0.00%	5.28%	0.00%
Applied Materials Inc	AMAT	793.61	372.30	295,460.95	0.80%	0.49%	0.00%	18.89%	0.15%
Amcor PLC	AMCR	462.05	48.43	22,376.87	0.06%	5.37%	0.00%	9.93%	0.01%
Advanced Micro Devices Inc	AMD	1,630.41	200.21	326,424.55				48.15%	
AMETEK Inc	AME	228.98	239.22	54,775.93	0.15%	0.57%	0.00%	9.07%	0.01%
Amgen Inc	AMGN	539.07	388.16	209,244.51	0.57%	2.60%	0.01%	1.00%	0.01%
Ameriprise Financial Inc	AMP	91.18	470.12	42,865.07	0.12%	1.36%	0.00%	10.31%	0.01%
American Tower Corp	AMT	466.08	191.86	89,423.03		3.54%			
Amazon.com Inc	AMZN	10,734.92	210.00	2,254,333.38	6.09%			18.30%	1.11%
Arista Networks Inc	ANET	1,256.54	133.50	167,747.81	0.45%			17.94%	0.08%
Aon PLC	AON	214.25	335.47	71,875.96		0.89%			
A O Smith Corp	AOS	113.37	78.00	8,843.03		1.85%			
APA Corp	APA	353.25	30.37	10,728.25		3.29%		-23.17%	
Air Products and Chemicals Inc	APD	222.66	275.67	61,379.58	0.17%	2.63%	0.00%	6.86%	0.01%
Amphenol Corp	APH	1,229.21	146.06	179,539.13		0.68%		21.90%	
Apollo Global Management Inc	APO	578.25	104.60	60,484.67	0.16%	1.95%	0.00%	14.55%	0.02%
AppLovin Corp	APP	307.07	434.77	133,504.82				47.15%	
Aptiv PLC	APTV	212.75	73.54	15,645.52					
Alexandria Real Estate Equities Inc	ARE	173.30	54.04	9,365.15		5.33%		-10.82%	
Ares Management Corp	ARES	220.90	112.01	24,743.30		4.82%		28.84%	
Atmos Energy Corp	ATO	165.44	186.79	30,902.34	0.08%	2.14%	0.00%	9.02%	0.01%
AvalonBay Communities Inc	AVB	140.08	177.23	24,826.99	0.07%	4.02%	0.00%	4.13%	0.00%
Broadcom Inc	AVGO	4,741.27	319.55	1,515,074.04		0.81%		35.56%	
Avery Dennison Corp	AVY	76.88	196.35	15,094.98	0.04%	1.91%	0.00%	5.53%	0.00%
American Water Works Co Inc	AWK	195.21	136.03	26,554.24	0.07%	2.43%	0.00%	7.04%	0.01%
Axon Enterprise Inc	AXON	80.40	542.40	43,607.70				33.23%	
American Express Co	AXP	686.61	308.90	212,095.07	0.57%	1.06%	0.01%	14.24%	0.08%
AutoZone Inc	AZO	16.57	3,755.58	62,221.77	0.17%			14.21%	0.02%
Boeing Co/The	BA	785.35	227.53	178,690.03					
Bank of America Corp	BAC	7,176.68	49.83	357,614.07		2.25%			
Ball Corp	BALL	266.08	66.93	17,808.55	0.05%	1.20%	0.00%	13.36%	0.01%
Baxter International Inc	BAX	514.49	20.37	10,480.16		0.20%		-2.87%	
Best Buy Co Inc	BBY	209.54	61.97	12,984.89	0.04%	6.13%	0.00%	4.46%	0.00%
Becton Dickinson & Co	BDX	284.74	176.48	50,251.23	0.14%	2.38%	0.00%	1.10%	0.00%
Franklin Resources Inc	BEN	520.76	26.54	13,821.06	0.04%	4.97%	0.00%	12.01%	0.00%
Brown-Forman Corp	BF/B	294.59	28.86	8,502.00	0.02%	3.20%	0.00%	2.43%	0.00%
Bunge Global SA	BG	193.51	120.65	23,346.87	0.06%	2.32%	0.00%	19.44%	0.01%
Biogen Inc	BIIB	146.76	191.82	28,151.22	0.08%			4.41%	0.00%
Bank of New York Mellon Corp/The	BK	686.91	119.10	81,810.67	0.22%	1.78%	0.00%	12.87%	0.03%
Booking Holdings Inc	BKNG	31.67	4,239.35	134,274.42	0.36%	0.99%	0.00%	16.40%	0.06%
Baker Hughes Co	BKR	988.24	65.26	64,492.31	0.17%	1.41%	0.00%	14.08%	0.02%
Builders FirstSource Inc	BLDR	110.61	104.29	11,535.00	0.03%			10.56%	0.00%
Blackrock Inc	BLK	155.54	1,063.23	165,376.43	0.45%	2.16%	0.01%	15.14%	0.07%
Bristol-Myers Squibb Co	BMY	2,036.47	62.37	127,014.87		4.04%		53.01%	
Broadridge Financial Solutions Inc	BR	116.75	185.87	21,700.08		2.10%			
Berkshire Hathaway Inc	BRK/B	1,372.82	504.95	693,205.53					
Brown & Brown Inc	BRO	340.42	71.82	24,448.97		0.92%			
Boston Scientific Corp	BSX	1,483.89	76.85	114,036.60	0.31%			13.45%	0.04%
Blackstone Inc	BX	742.18	113.37	84,141.03		5.26%		20.02%	
BXP Inc	BXP	158.63	57.58	9,133.86	0.02%	4.86%	0.00%	3.36%	0.00%
Citigroup Inc	C	1,749.32	110.19	192,757.46	0.52%	2.18%	0.01%	19.71%	0.10%

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Conagra Brands Inc	CAG	478.37	19.25	9,208.61		7.27%		-8.19%	
Cardinal Health Inc	CAH	235.32	229.23	53,941.49	0.15%	0.89%	0.00%	14.74%	0.02%
Carrier Global Corp	CARR	835.84	64.40	53,828.35	0.15%	1.49%	0.00%	9.39%	0.01%
Caterpillar Inc	CAT	465.29	742.83	345,629.39		0.81%		25.31%	
Chubb Ltd	CB	390.16	340.86	132,988.76	0.36%	1.14%	0.00%	3.42%	0.01%
Cboe Global Markets Inc	CBOE	104.67	299.72	31,371.00	0.08%	0.96%	0.00%	13.75%	0.01%
CBRE Group Inc	CBRE	295.16	147.66	43,583.11					
Crown Castle Inc	CCI	436.07	89.54	39,045.75		4.75%			
Carnival Corp	CCL	1,236.71	31.55	39,018.09	0.11%	1.90%	0.00%	11.20%	0.01%
Cadence Design Systems Inc	CDNS	275.88	301.40	83,148.87	0.22%			14.61%	0.03%
CDW Corp/DE	CDW	128.99	122.64	15,819.77	0.04%	2.05%	0.00%	7.25%	0.00%
Constellation Energy Corp	CEG	362.36	329.88	119,533.83	0.32%	0.52%	0.00%	15.42%	0.05%
CF Industries Holdings Inc	CF	153.67	99.54	15,296.19		2.01%		-16.61%	
Citizens Financial Group Inc	CFG	424.98	60.19	25,579.77		3.06%		24.19%	
Church & Dwight Co Inc	CHD	236.69	104.86	24,819.76	0.07%	1.17%	0.00%	7.21%	0.00%
CH Robinson Worldwide Inc	CHRW	118.62	185.25	21,974.51	0.06%	1.36%	0.00%	17.23%	0.01%
Charter Communications Inc	CHTR	126.63	234.63	29,711.56				21.90%	
Cigna Group/The	CI	263.53	289.82	76,375.77	0.21%	2.15%	0.00%	9.89%	0.02%
Ciena Corp	CIEN	141.46	348.70	49,328.31				41.75%	
Cincinnati Financial Corp	CINF	155.62	163.98	25,518.17	0.07%	2.29%	0.00%	5.30%	0.00%
Colgate-Palmolive Co	CL	801.55	99.14	79,465.47	0.21%	2.10%	0.00%	5.54%	0.01%
Clorox Co/The	CLX	120.91	127.16	15,375.15		3.90%		-0.22%	
Comcast Corp	CMCSA	3,588.40	30.96	111,096.91		4.26%		-3.89%	
CME Group Inc	CME	358.62	319.50	114,579.83	0.31%	1.63%	0.01%	5.82%	0.02%
Chipotle Mexican Grill Inc	CMG	1,302.42	37.22	48,476.18	0.13%			12.82%	0.02%
Cummins Inc	CMI	138.17	583.87	80,670.67	0.22%	1.37%	0.00%	14.29%	0.03%
CMS Energy Corp	CMS	306.42	78.07	23,922.28	0.06%	2.92%	0.00%	7.27%	0.00%
Centene Corp	CNC	491.77	44.88	22,070.68				42.35%	
CenterPoint Energy Inc	CNP	652.87	43.50	28,399.77	0.08%	2.11%	0.00%	8.95%	0.01%
Capital One Financial Corp	COF	621.93	195.64	121,674.70	0.33%	1.64%	0.01%	13.86%	0.05%
Coinbase Global Inc	COIN	223.04	175.85	39,221.81				23.32%	
Cooper Cos Inc/The	COO	195.11	83.67	16,325.21	0.04%			7.77%	0.00%
ConocoPhillips	COP	1,222.34	113.46	138,686.60		2.96%			
Cencora Inc	COR	194.53	372.14	72,392.65	0.20%	0.64%	0.00%	10.42%	0.02%
Costco Wholesale Corp	COST	443.87	1,010.79	448,658.76	1.21%	0.51%	0.01%	11.37%	0.14%
Corpay Inc	CPAY	68.05	325.10	22,123.15	0.06%			12.37%	0.01%
Campbell's Company/The	CPB	298.13	26.95	8,034.72		5.79%		-3.24%	
Copart Inc	CPRT	968.02	38.09	36,871.79					
Camden Property Trust	CPT	103.41	108.34	11,203.25	0.03%	3.91%	0.00%	2.13%	0.00%
CRH PLC	CRH	668.25	119.98	80,176.73	0.22%	1.30%	0.00%	9.98%	0.02%
Charles River Laboratories International Inc	CRL	49.23	178.49	8,786.67	0.02%			7.41%	0.00%
Salesforce Inc	CRM	937.00	194.79	182,518.23	0.49%	0.90%	0.00%	12.79%	0.06%
Crowdstrike Holdings Inc	CRWD	252.10	371.98	93,775.58				23.15%	
Cisco Systems Inc	CSCO	3,949.89	79.46	313,858.50	0.85%	2.11%	0.02%	7.80%	0.07%
CoStar Group Inc	CSGP	419.79	44.63	18,735.37				42.74%	
CSX Corp	CSX	1,859.56	42.69	79,384.48	0.21%	1.31%	0.00%	14.00%	0.03%
Cintas Corp	CTAS	399.89	201.13	80,429.81	0.22%	0.89%	0.00%	10.79%	0.02%
Coterra Energy Inc	CTRA	759.27	30.59	23,226.15		2.88%		23.71%	
Cognizant Technology Solutions Corp	CTSH	478.25	64.43	30,813.45		2.05%			
Corteva Inc	CTVA	683.01	79.94	54,600.19	0.15%	0.90%	0.00%	9.29%	0.01%
Carvana Co	CVNA	142.74	334.16	47,696.73					
CVS Health Corp	CVS	1,272.21	79.90	101,649.66	0.27%	3.33%	0.01%	13.13%	0.04%
Chevron Corp	CVX	1,995.39	186.76	372,658.20		3.81%		-8.85%	
Dominion Energy Inc	D	878.79	63.14	55,486.52	0.15%	4.23%	0.01%	13.32%	0.02%
Delta Air Lines Inc	DAL	653.13	65.70	42,910.69	0.12%	1.14%	0.00%	14.65%	0.02%
DoorDash Inc	DASH	409.97	176.47	72,346.85				39.94%	
DuPont de Nemours Inc	DD	408.92	49.84	20,380.77	0.06%	1.61%	0.00%	17.42%	0.01%
Datadog Inc	DDOG	328.48	111.96	36,777.00				24.38%	
Deere & Co	DE	270.11	629.71	170,089.26	0.46%	1.03%	0.00%	16.83%	0.08%
Deckers Outdoor Corp	DECK	141.95	117.27	16,646.47	0.04%			6.38%	0.00%
Dell Technologies Inc	DELL	333.92	148.08	49,446.55	0.13%	1.42%	0.00%	18.13%	0.02%
Dollar General Corp	DG	220.12	156.24	34,391.37	0.09%	1.51%	0.00%	8.97%	0.01%
Quest Diagnostics Inc	DGX	109.87	211.91	23,281.77	0.06%	1.62%	0.00%	7.25%	0.00%
DR Horton Inc	DHI	289.70	160.39	46,465.53	0.13%	1.12%	0.00%	5.46%	0.01%
Danaher Corp	DHR	707.14	210.64	148,951.83	0.40%	0.76%	0.00%	7.82%	0.03%
Walt Disney Co/The	DIS	1,771.52	106.04	187,851.96	0.51%	1.41%	0.01%	11.32%	0.06%
Digital Realty Trust Inc	DLR	343.62	177.20	60,888.66	0.16%	2.75%	0.00%	7.38%	0.01%
Dollar Tree Inc	DLTR	198.85	126.48	25,150.95	0.07%			11.87%	0.01%
Healthpeak Properties Inc	DOC	695.04	17.68	12,288.38	0.03%	6.90%	0.00%	1.08%	0.00%
Dover Corp	DOV	134.87	225.50	30,412.43	0.08%	0.92%	0.00%	9.65%	0.01%
Dow Inc	DOW	705.76	30.73	21,688.14		4.56%		54.00%	
Domino's Pizza Inc	DPZ	33.63	402.51	13,535.97	0.04%	1.98%	0.00%	11.36%	0.00%
Darden Restaurants Inc	DRI	115.14	213.85	24,622.53	0.07%	2.81%	0.00%	10.65%	0.01%
DTE Energy Co	DTE	207.68	148.24	30,786.93	0.08%	3.14%	0.00%	7.38%	0.01%
Duke Energy Corp	DUK	778.00	130.85	101,801.30	0.28%	3.26%	0.01%	6.69%	0.02%
DaVita Inc	DVA	66.80	156.30	10,440.84				25.82%	
Devon Energy Corp	DVN	620.00	43.53	26,988.60	0.07%	2.21%	0.00%	1.93%	0.00%
Dexcom Inc	DXCM	384.86	73.43	28,260.63	0.08%			16.87%	0.01%
Electronic Arts Inc	EA	250.25	200.57	50,193.39	0.14%	0.38%	0.00%	13.01%	0.02%
eBay Inc	EBAY	448.00	90.86	40,705.28	0.11%	1.36%	0.00%	9.91%	0.01%
Ecolab Inc	ECL	281.97	308.35	86,945.28	0.23%	0.95%	0.00%	12.93%	0.03%
Consolidated Edison Inc	ED	361.25	112.52	40,647.56	0.11%	3.15%	0.00%	7.39%	0.01%
Equifax Inc	EFX	120.27	208.96	25,131.62	0.07%	1.07%	0.00%	17.72%	0.01%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Everest Group Ltd	EG	40.39	335.49	13,550.49		2.38%		26.06%	
Edison International	EIX	384.79	74.74	28,759.27	0.08%	4.70%	0.00%	7.58%	0.01%
Estee Lauder Cos Inc/The	EL	247.22	109.47	27,063.14		1.28%		39.63%	
Elevance Health Inc	ELV	220.70	320.00	70,625.49	0.19%	2.15%	0.00%	2.04%	0.00%
EMCOR Group Inc	EME	44.53	724.62	32,269.19		0.22%			
Emerson Electric Co	EMR	562.00	150.75	84,721.50	0.23%	1.47%	0.00%	10.43%	0.02%
EOG Resources Inc	EOG	536.49	124.08	66,567.86		3.29%		-1.03%	
EPAM Systems Inc	EPAM	54.14	141.00	7,633.74					
Equinix Inc	EQIX	98.25	974.26	95,725.85	0.26%	2.12%	0.01%	15.00%	0.04%
Equity Residential	EQR	377.55	63.21	23,864.75	0.06%	4.38%	0.00%	3.24%	0.00%
EQT Corp	EQT	624.27	61.42	38,342.91		1.07%		34.05%	
Erie Indemnity Co	ERIE	46.19	269.44	12,445.18		2.17%			
Eversource Energy	ES	375.50	76.21	28,616.60	0.08%	4.13%	0.00%	4.71%	0.00%
Essex Property Trust Inc	ESS	64.48	255.11	16,448.35	0.04%	4.06%	0.00%	1.99%	0.00%
Eaton Corp PLC	ETN	387.90	375.92	145,819.37		1.17%			
Entergy Corp	ETR	452.99	107.11	48,519.74	0.13%	2.39%	0.00%	11.15%	0.01%
Evergy Inc	EVRG	229.75	83.66	19,220.55	0.05%	3.32%	0.00%	5.91%	0.00%
Edwards Lifesciences Corp	EW	580.80	86.47	50,221.78	0.14%			12.45%	0.02%
Exelon Corp	EXC	1,009.54	49.05	49,517.72	0.13%	3.43%	0.00%	5.92%	0.01%
Expand Energy Corp	EXE	240.40	107.92	25,943.78		2.13%		58.23%	
Expeditors International of Washington Inc	EXPD	133.50	145.03	19,362.04	0.05%	1.06%	0.00%	8.97%	0.00%
Expedia Group Inc	EXPE	117.01	215.69	25,238.19		0.89%		21.20%	
Extra Space Storage Inc	EXR	211.14	151.03	31,888.12	0.09%	4.29%	0.00%	2.03%	0.00%
Ford Motor Co	F	3,918.62	14.09	55,213.40		4.26%			
Diamondback Energy Inc	FANG	282.08	174.08	49,104.31		2.41%		-5.23%	
Fastenal Co	FAST	1,148.33	46.04	52,869.04	0.14%	2.09%	0.00%	11.48%	0.02%
Freeport-McMoRan Inc	FCX	1,437.20	68.08	97,844.69		0.88%		27.40%	
FactSet Research Systems Inc	FDS	37.10	216.81	8,043.49	0.02%	2.03%	0.00%	4.86%	0.00%
FedEx Corp	FDX	235.12	387.00	90,992.53	0.25%	1.50%	0.00%	11.09%	0.03%
FirstEnergy Corp	FE	577.13	51.16	29,525.78	0.08%	3.64%	0.00%	7.29%	0.01%
F5 Inc	FFIV	56.52	271.36	15,337.07	0.04%			2.91%	0.00%
Fair Isaac Corp	FICO	23.72	1,409.36	33,433.02				31.35%	
Fidelity National Information Services Inc	FIS	514.40	50.96	26,214.01		3.45%			
Fiserv Inc	FISV	534.78	62.29	33,311.29					
Fifth Third Bancorp	FITB	899.70	49.47	44,508.17		3.23%			
Comfort Systems USA Inc	FIX	35.17	1,429.37	50,278.05		0.20%		24.00%	
Fox Corp	FOX	224.70	51.73	11,623.85	0.03%	1.08%	0.00%	1.58%	0.00%
Fox Corp	FOXA	200.69	56.34	11,307.09	0.03%	0.99%	0.00%	1.58%	0.00%
Federal Realty Investment Trust	FRT	86.28	108.77	9,384.24	0.03%	4.16%	0.00%	4.66%	0.00%
First Solar Inc	FSLR	107.31	197.20	21,161.73				37.78%	
Fortinet Inc	FTNT	739.92	79.03	58,476.16					
Fortive Corp	FTV	307.86	59.20	18,225.26		0.41%			
General Dynamics Corp	GD	270.39	357.05	96,542.66	0.26%	1.68%	0.00%	10.51%	0.03%
GoDaddy Inc	GDDY	133.35	87.16	11,623.15					
General Electric Co	GE	1,048.81	342.26	358,966.95	0.97%	0.55%	0.01%	15.18%	0.15%
GE HealthCare Technologies Inc	GEHC	455.75	84.27	38,406.03	0.10%	0.17%	0.00%	10.18%	0.01%
Gen Digital Inc	GEN	605.66	22.57	13,669.83	0.04%	2.22%	0.00%	13.08%	0.00%
GE Vernova Inc	GEV	269.53	873.60	235,460.94		0.23%		67.22%	
Gilead Sciences Inc	GILD	1,241.42	148.95	184,909.59	0.50%	2.20%	0.01%	7.32%	0.04%
General Mills Inc	GIS	533.58	45.23	24,133.92		5.39%		-6.42%	
Globe Life Inc	GL	78.64	145.26	11,422.83		0.91%			
Corning Inc	GLW	857.95	150.38	129,018.24		0.74%		26.81%	
General Motors Co	GM	903.97	78.71	71,151.31		0.91%			
Generac Holdings Inc	GNRC	58.68	225.37	13,223.77					
Alphabet Inc	GOOG	5,438.00	311.43	1,693,556.34	4.58%	0.27%	0.01%	10.11%	0.46%
Alphabet Inc	GOOGL	5,822.00	311.76	1,815,066.72	4.90%	0.27%	0.01%	10.11%	0.50%
Genuine Parts Co	GPC	139.12	119.26	16,591.70		3.56%			
Global Payments Inc	GPN	279.90	76.46	21,401.26		1.31%			
Garmin Ltd	GRMN	192.48	252.83	48,664.93	0.13%	1.66%	0.00%	8.88%	0.01%
Goldman Sachs Group Inc/The	GS	296.75	855.07	253,744.52	0.69%	2.11%	0.01%	14.78%	0.10%
WW Grainger Inc	GWW	47.37	1,144.73	54,229.32	0.15%	0.79%	0.00%	8.76%	0.01%
Halliburton Co	HAL	837.55	36.00	30,151.74	0.08%	1.89%	0.00%	7.42%	0.01%
Hasbro Inc	HAS	140.69	99.59	14,010.89	0.04%	2.81%	0.00%	10.25%	0.00%
Huntington Bancshares Inc/OH	HBAN	2,030.00	16.80	34,104.00		3.69%			
HCA Healthcare Inc	HCA	223.62	529.70	118,452.68	0.32%	0.59%	0.00%	8.56%	0.03%
Home Depot Inc/The	HD	995.51	380.72	379,011.13	1.02%	2.45%	0.03%	6.09%	0.06%
Hartford Insurance Group Inc/The	HIG	275.86	140.23	38,684.33		1.71%			
Huntington Ingalls Industries Inc	HII	39.24	444.52	17,444.16	0.05%	1.24%	0.00%	17.55%	0.01%
Hilton Worldwide Holdings Inc	HLT	229.29	311.78	71,488.54	0.19%	0.19%	0.00%	12.94%	0.02%
Hologic Inc	HOLX	223.24	75.36	16,823.74	0.05%			9.00%	0.00%
Honeywell International Inc	HON	635.68	243.59	154,844.24	0.42%	1.95%	0.01%	7.71%	0.03%
Robinhood Markets Inc	HOOD	790.05	75.85	59,925.65	0.16%			17.60%	0.03%
Hewlett Packard Enterprise Co	HPE	1,328.81	21.47	28,529.52	0.08%	2.65%	0.00%	18.64%	0.01%
HP Inc	HPQ	914.55	18.99	17,367.31	0.05%	6.32%	0.00%	1.27%	0.00%
Hormel Foods Corp	HRL	550.28	25.60	14,087.28	0.04%	4.57%	0.00%	6.61%	0.00%
Henry Schein Inc	HSIC	114.70	82.39	9,450.47	0.03%			7.01%	0.00%
Host Hotels & Resorts Inc	HST	687.80	19.59	13,474.04		4.08%		-1.83%	
Hershey Co/The	HSY	148.08	236.28	34,987.74	0.09%	2.46%	0.00%	16.20%	0.02%
Hubbell Inc	HUBB	53.16	511.63	27,199.07		1.11%			
Humana Inc	HUM	120.60	190.54	22,978.36	0.06%	1.86%	0.00%	14.94%	0.01%
Howmet Aerospace Inc	HWM	400.94	262.53	105,258.79		0.18%		20.01%	
Interactive Brokers Group Inc	IBKR	445.44	71.19	31,710.84	0.09%	0.45%	0.00%	15.21%	0.01%
International Business Machines Corp	IBM	938.03	240.21	225,325.24	0.61%	2.80%	0.02%	6.14%	0.04%

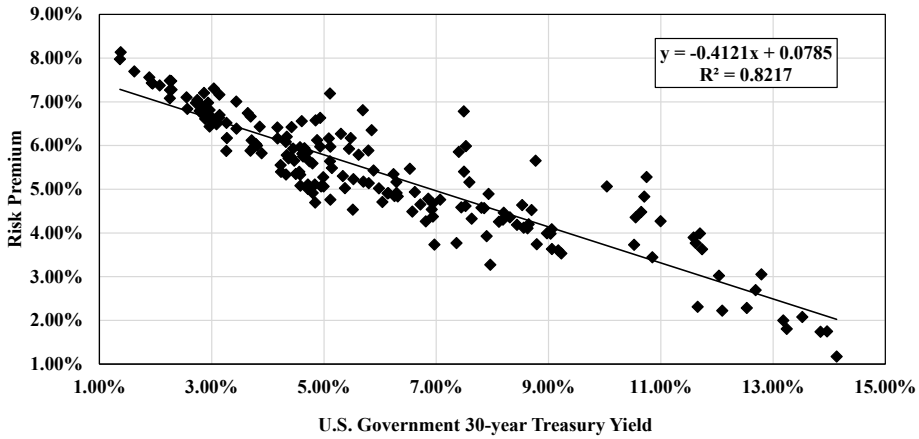
Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Intercontinental Exchange Inc	ICE	567.90	164.13	93,208.85	0.25%	1.27%	0.00%	16.14%	0.04%
IDEXX Laboratories Inc	IDXX	79.62	656.73	52,291.49	0.14%			11.32%	0.02%
IDEX Corp	IEX	74.35	209.47	15,573.64		1.36%			
International Flavors & Fragrances Inc	IFF	255.48	82.23	21,007.91	0.06%	1.95%	0.00%	9.82%	0.01%
Incyte Corp	INCY	199.01	101.27	20,154.20				25.00%	
Intel Corp	INTC	4,995.00	45.61	227,821.95				27.92%	
Intuit Inc	INTU	276.55	409.03	113,117.25	0.31%	1.17%	0.00%	14.47%	0.04%
Invitation Homes Inc	INVH	609.39	26.34	16,051.23	0.04%	4.56%	0.00%	3.54%	0.00%
International Paper Co	IP	529.47	43.55	23,058.39		4.25%			
IQVIA Holdings Inc	IQV	169.70	178.81	30,344.06	0.08%			7.90%	0.01%
Ingersoll Rand Inc	IR	391.62	94.14	36,866.92		0.08%			
Iron Mountain Inc	IRM	295.84	108.33	32,047.83		3.19%			
Intuitive Surgical Inc	ISRG	355.13	503.51	178,811.63	0.48%			12.37%	0.06%
Gartner Inc	IT	70.45	157.20	11,074.79	0.03%			7.46%	0.00%
Illinois Tool Works Inc	ITW	288.20	290.63	83,759.57	0.23%	2.22%	0.01%	8.83%	0.02%
Invesco Ltd	IVZ	443.67	26.26	11,650.87	0.03%	3.20%	0.00%	19.45%	0.01%
Jacobs Solutions Inc	J	117.45	137.86	16,191.20	0.04%	1.04%	0.00%	13.57%	0.01%
JB Hunt Transport Services Inc	JBHT	94.60	233.41	22,081.54	0.06%	0.77%	0.00%	16.39%	0.01%
Jabil Inc	JBL	105.60	264.99	27,981.69	0.08%	0.12%	0.00%	14.77%	0.01%
Johnson Controls International plc	JCI	612.07	144.30	88,321.15	0.24%	1.11%	0.00%	18.90%	0.05%
Jack Henry & Associates Inc	JKHY	72.17	162.46	11,724.31		1.50%			
Johnson & Johnson	JNJ	2,409.90	248.43	598,691.19	1.62%	2.09%	0.03%	8.86%	0.14%
JPMorgan Chase & Co	JPM	2,697.03	300.30	809,918.82	2.19%	2.00%	0.04%	11.12%	0.24%
Keurig Dr Pepper Inc	KDP	1,358.67	30.28	41,140.41	0.11%	3.04%	0.00%	8.93%	0.01%
KeyCorp	KEY	1,089.65	20.54	22,377.76	0.06%	3.99%	0.00%	18.71%	0.01%
Keysight Technologies Inc	KEYS	171.80	307.33	52,799.29	0.14%			17.45%	0.02%
Kraft Heinz Co/The	KHC	1,183.74	24.61	29,131.96		6.50%		-6.02%	
Kimco Realty Corp	KIM	679.50	23.55	16,002.19	0.04%	4.42%	0.00%	3.32%	0.00%
KKR & Co Inc	KKR	891.55	87.68	78,171.18		0.84%			
KLA Corp	KLAC	131.08	1,524.55	199,832.85	0.54%	0.50%	0.00%	13.99%	0.08%
Kimberly-Clark Corp	KMB	331.92	111.44	36,989.43	0.10%	4.59%	0.00%	4.12%	0.00%
Kinder Morgan Inc	KMI	2,224.81	33.27	74,019.31		3.52%			
Coca-Cola Co/The	KO	4,300.72	81.56	350,766.97	0.95%	2.60%	0.02%	7.24%	0.07%
Kroger Co/The	KR	632.85	68.24	43,185.63	0.12%	2.05%	0.00%	6.90%	0.01%
Kenvue Inc	KVUE	1,916.73	19.12	36,647.92	0.10%	4.34%	0.00%	13.12%	0.01%
Loews Corp	L	206.05	110.02	22,669.94		0.23%			
Leidos Holdings Inc	LDOS	126.39	175.10	22,131.36	0.06%	0.98%	0.00%	11.62%	0.01%
Lennar Corp	LEN	216.51	114.36	24,759.89	0.07%	1.75%	0.00%	12.35%	0.01%
Labcorp Holdings Inc	LH	82.40	289.12	23,823.49	0.06%	1.00%	0.00%	7.23%	0.00%
L3Harris Technologies Inc	LHX	186.78	364.54	68,087.42	0.18%	1.37%	0.00%	13.72%	0.03%
Lennox International Inc	LII	34.80	569.94	19,835.57		0.91%			
Linde PLC	LIN	463.39	508.08	235,441.30	0.64%	1.26%	0.01%	9.05%	0.06%
Eli Lilly & Co	LLY	943.36	1,051.99	992,402.57	2.68%	0.66%	0.02%	14.00%	0.38%
Lockheed Martin Corp	LMT	230.08	654.63	150,617.43		2.11%		20.87%	
Alliant Energy Corp	LNT	257.14	72.34	18,601.57	0.05%	2.96%	0.00%	6.78%	0.00%
Lowe's Cos Inc	LOW	561.00	264.57	148,423.77	0.40%	1.81%	0.01%	3.65%	0.01%
Lam Research Corp	LRCX	1,248.77	233.89	292,075.05		0.44%		21.18%	
Lululemon Athletica Inc	LULU	112.19	185.17	20,774.23				-0.73%	
Southwest Airlines Co	LUV	491.32	49.26	24,202.32		1.46%		82.46%	
Las Vegas Sands Corp	LVS	671.91	56.72	38,110.78	0.10%	2.12%	0.00%	10.21%	0.01%
Lamb Weston Holdings Inc	LW	138.88	48.19	6,692.62		3.15%		-6.94%	
LyondellBasell Industries NV	LYB	322.17	56.83	18,308.92		4.86%		48.35%	
Live Nation Entertainment Inc	LYV	234.80	162.14	38,070.78					
Mastercard Inc	MA	885.22	517.21	457,842.77		0.67%			
Mid-America Apartment Communities Inc	MAA	116.90	133.86	15,648.37	0.04%	4.57%	0.00%	0.61%	0.00%
Marriott International Inc/MD	MAR	264.98	341.73	90,553.17	0.24%	0.78%	0.00%	11.09%	0.03%
Masco Corp	MAS	203.61	71.62	14,582.34	0.04%	1.79%	0.00%	6.72%	0.00%
McDonald's Corp	MCD	710.40	339.17	240,942.35	0.65%	2.19%	0.01%	9.05%	0.06%
Microchip Technology Inc	MCHP	541.14	74.64	40,390.35		2.44%		34.96%	
McKesson Corp	MCK	122.49	986.55	120,840.00	0.33%	0.33%	0.00%	14.56%	0.05%
Moody's Corp	MCO	177.30	476.56	84,494.05	0.23%	0.86%	0.00%	12.16%	0.03%
Mondelez International Inc	MDLZ	1,281.85	61.58	78,936.06	0.21%	3.25%	0.01%	7.72%	0.02%
Medtronic PLC	MDT	1,283.88	97.66	125,384.21	0.34%	2.91%	0.01%	7.53%	0.03%
MetLife Inc	MET	652.05	72.07	46,993.52	0.13%	3.15%	0.00%	12.62%	0.02%
Meta Platforms Inc	META	2,187.18	648.18	1,417,684.87	3.83%	0.32%	0.01%	17.07%	0.65%
MGM Resorts International	MGM	255.83	36.86	9,429.84					
McCormick & Co Inc/MD	MKC	253.59	71.04	18,015.07	0.05%	2.70%	0.00%	5.27%	0.00%
Martin Marietta Materials Inc	MLM	60.31	675.74	40,755.26		0.49%		-7.47%	
3M Co	MMM	526.70	165.32	87,074.04	0.24%	1.89%	0.00%	6.70%	0.02%
Monster Beverage Corp	MNST	978.27	85.30	83,446.49	0.23%			11.57%	0.03%
Altria Group Inc	MO	1,671.90	69.04	115,427.84	0.31%	6.14%	0.02%	2.81%	0.01%
Molina Healthcare Inc	MOH	51.50	154.05	7,933.58	0.02%			19.43%	0.00%
Mosaic Co/The	MOS	317.51	27.84	8,839.35	0.02%	3.16%	0.00%	10.89%	0.00%
Marathon Petroleum Corp	MPC	294.74	198.21	58,420.45		2.02%			
Monolithic Power Systems Inc	MPWR	49.12	1,142.74	56,129.10		0.70%			
Merck & Co Inc	MRK	2,472.39	123.82	306,131.58		2.75%			
Moderna Inc	MRNA	394.94	53.57	21,156.90				24.62%	
Marsh & McLennan Cos Inc	MRSH	484.12	186.74	90,405.36		1.93%			
Morgan Stanley	MS	1,587.86	166.51	264,394.60	0.71%	2.40%	0.02%	9.41%	0.07%
MSCI Inc	MSCI	73.47	571.83	42,014.66	0.11%	1.43%	0.00%	13.40%	0.02%
Microsoft Corp	MSFT	7,425.63	392.74	2,916,341.56		0.93%			
Motorola Solutions Inc	MSI	165.66	482.26	79,890.67	0.22%	1.00%	0.00%	8.80%	0.02%
M&T Bank Corp	MTB	149.00	215.48	32,106.57	0.09%	2.78%	0.00%	11.47%	0.01%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Match Group Inc	MTCH	232.64	31.60	7,351.57	0.02%	2.53%	0.00%	16.50%	0.00%
Mettler-Toledo International Inc	MTD	20.33	1,366.69	27,778.32	0.08%			10.25%	0.01%
Micron Technology Inc	MU	1,125.51	412.37	464,126.25		0.11%		59.90%	
Norwegian Cruise Line Holdings Ltd	NCLH	455.26	24.79	11,285.83	0.03%			14.54%	0.00%
Nasdaq Inc	NDAQ	568.44	87.58	49,784.31	0.13%	1.23%	0.00%	16.20%	0.02%
Nordson Corp	NDSN	55.78	293.44	16,369.14		1.12%			
NextEra Energy Inc	NEE	2,083.52	93.77	195,371.85	0.53%	2.66%	0.01%	7.70%	0.04%
Newmont Corp	NEM	1,087.87	129.74	141,137.97		0.80%		-2.37%	
Netflix Inc	NFLX	4,222.16	96.24	406,340.89					
NiSource Inc	NI	478.53	47.30	22,634.62	0.06%	2.54%	0.00%	8.27%	0.01%
NIKE Inc	NKE	1,191.50	61.77	73,598.69	0.20%	2.66%	0.01%	14.71%	0.03%
Northrop Grumman Corp	NOC	141.92	724.38	102,805.18	0.28%	1.28%	0.00%	7.20%	0.02%
ServiceNow Inc	NOW	1,046.00	108.01	112,978.46					
NRG Energy Inc	NRG	214.68	178.96	38,418.69		1.06%			
Norfolk Southern Corp	NSC	224.57	314.74	70,681.80		1.72%			
NetApp Inc	NTAP	197.33	99.03	19,541.63	0.05%	2.10%	0.00%	4.98%	0.00%
Northern Trust Corp	NTRS	185.83	143.09	26,590.10	0.07%	2.24%	0.00%	10.50%	0.01%
Nucor Corp	NUE	227.77	176.88	40,288.77		1.27%		23.67%	
NVIDIA Corp	NVDA	24,300.00	177.19	4,305,717.00		0.02%		42.55%	
NVR Inc	NVR	2.79	7,517.79	21,002.90	0.06%			7.04%	0.00%
News Corp	NWS	185.15	26.78	4,958.38		0.75%			
News Corp	NWSA	370.23	24.29	8,992.78		0.82%			
NXP Semiconductors NV	NXPI	252.69	227.01	57,363.80	0.15%	1.79%	0.00%	14.09%	0.02%
Realty Income Corp	O	932.44	67.00	62,473.49	0.17%	4.84%	0.01%	3.82%	0.01%
Old Dominion Freight Line Inc	ODFL	208.43	203.05	42,320.82		0.57%			
ONEOK Inc	OKE	629.78	82.77	52,127.19	0.14%	5.17%	0.01%	3.06%	0.00%
Omnicom Group Inc	OMC	310.34	85.29	26,468.59	0.07%	3.75%	0.00%	6.79%	0.00%
ON Semiconductor Corp	ON	394.02	66.48	26,194.48				24.64%	
Oracle Corp	ORCL	2,873.13	145.40	417,753.10		1.38%		26.75%	
O'Reilly Automotive Inc	ORLY	838.49	93.88	78,717.16	0.21%			9.97%	0.02%
Otis Worldwide Corp	OTIS	388.72	92.56	35,979.99		1.82%			
Occidental Petroleum Corp	OXY	986.27	53.08	52,351.03		1.96%		-31.27%	
Palo Alto Networks Inc	PANW	816.00	148.92	121,518.72					
Paycom Software Inc	PAYC	54.28	125.83	6,829.44		1.19%			
Paychex Inc	PAYX	358.97	93.65	33,617.30		4.61%			
PACCAR Inc	PCAR	525.89	126.09	66,310.03		1.05%		21.56%	
PG&E Corp	PCG	2,197.97	19.00	41,761.39	0.11%	1.05%	0.00%	12.55%	0.01%
Public Service Enterprise Group Inc	PEG	498.74	86.07	42,926.54	0.12%	3.11%	0.00%	7.54%	0.01%
PepsiCo Inc	PEP	1,366.65	169.74	231,975.01	0.63%	3.35%	0.02%	5.84%	0.04%
Pfizer Inc	PFE	5,686.27	27.65	157,225.29		6.22%			
Principal Financial Group Inc	PFG	216.84	95.42	20,690.41	0.06%	3.35%	0.00%	11.50%	0.01%
Procter & Gamble Co/The	PG	2,324.00	167.20	388,572.92	1.05%	2.53%	0.03%	4.48%	0.05%
Progressive Corp/The	PGR	586.10	213.66	125,226.13	0.34%	0.19%	0.00%	1.40%	0.00%
Parker-Hannifin Corp	PH	126.22	1,009.18	127,375.20	0.34%	0.71%	0.00%	10.02%	0.03%
PulteGroup Inc	PHM	192.33	137.20	26,387.39	0.07%	0.76%	0.00%	5.96%	0.00%
Packaging Corp of America	PKG	89.21	232.14	20,710.00	0.06%	2.15%	0.00%	11.62%	0.01%
Prologis Inc	PLD	926.18	142.57	132,044.77	0.36%	3.00%	0.01%	6.61%	0.02%
Palantir Technologies Inc	PLTR	2,291.47	137.19	314,366.87				47.57%	
Philip Morris International Inc	PM	1,556.68	186.83	290,834.45	0.79%	3.15%	0.02%	10.23%	0.08%
PNC Financial Services Group Inc/The	PNC	403.37	212.35	85,655.81	0.23%	3.20%	0.01%	13.05%	0.03%
Pentair PLC	PNR	163.24	99.19	16,191.35		1.09%			
Pinnacle West Capital Corp	PNW	120.91	100.30	12,126.81	0.03%	3.63%	0.00%	7.00%	0.00%
Insulet Corp	PODD	70.40	246.61	17,360.32				26.20%	
Pool Corp	POOL	36.79	227.18	8,357.46	0.02%	2.20%	0.00%	7.73%	0.00%
PPG Industries Inc	PPG	223.49	123.27	27,550.19	0.07%	2.30%	0.00%	8.75%	0.01%
PPL Corp	PPL	751.31	38.98	29,285.95	0.08%	2.92%	0.00%	8.40%	0.01%
Prudential Financial Inc	PRU	348.00	98.38	34,236.24		5.69%			
Public Storage	PSA	175.51	307.06	53,891.01	0.15%	3.91%	0.01%	2.92%	0.00%
Paramount Skydance Corp	PSKY	1,080.24	13.51	14,594.06		1.48%			
Phillips 66	PSX	400.74	154.33	61,846.82		3.29%			
PTC Inc	PTC	119.00	156.59	18,633.60	0.05%			7.40%	0.00%
Quanta Services Inc	PWR	149.62	563.08	84,247.71	0.23%	0.08%	0.00%	18.42%	0.04%
PayPal Holdings Inc	PYPL	920.66	46.21	42,543.91	0.11%	1.21%	0.00%	13.23%	0.02%
Qnity Electronics Inc	Q	209.66	126.76	26,576.36		0.25%			
QUALCOMM Inc	QCOM	1,067.00	142.36	151,898.12	0.41%	2.50%	0.01%	2.35%	0.01%
Royal Caribbean Cruises Ltd	RCL	270.53	310.96	84,123.48	0.23%	1.93%	0.00%	13.63%	0.03%
Regency Centers Corp	REG	182.91	79.00	14,449.62	0.04%	3.82%	0.00%	4.80%	0.00%
Regeneron Pharmaceuticals Inc	REGN	103.90	781.67	81,217.59	0.22%	0.48%	0.00%	12.00%	0.03%
Regions Financial Corp	RF	863.51	27.57	23,802.56	0.06%	3.85%	0.00%	8.79%	0.01%
Raymond James Financial Inc	RJF	197.09	153.08	30,170.70	0.08%	1.41%	0.00%	14.18%	0.01%
Ralph Lauren Corp	RL	38.66	362.60	14,016.35	0.04%	1.01%	0.00%	18.14%	0.01%
ResMed Inc	RMD	145.68	256.26	37,331.55	0.10%	0.94%	0.00%	9.44%	0.01%
Rockwell Automation Inc	ROK	112.36	407.45	45,780.23	0.12%	1.35%	0.00%	14.96%	0.02%
Rollins Inc	ROL	481.09	60.89	29,293.71	0.08%	1.20%	0.00%	13.09%	0.01%
Roper Technologies Inc	ROP	102.93	349.73	35,996.84		1.04%			
Ross Stores Inc	ROST	323.44	205.64	66,513.22	0.18%	0.79%	0.00%	7.04%	0.01%
Republic Services Inc	RSG	308.80	229.00	70,716.34	0.19%	1.09%	0.00%	7.99%	0.02%
RTX Corp	RTX	1,342.29	202.62	271,974.33	0.73%	1.34%	0.01%	10.12%	0.07%
Revvity Inc	RVTY	111.80	98.31	10,991.00	0.03%	0.28%	0.00%	8.71%	0.00%
SBA Communications Corp	SBAC	105.79	201.16	21,280.43		2.49%		-5.46%	
Starbucks Corp	SBUX	1,139.30	98.02	111,674.19	0.30%	2.53%	0.01%	16.75%	0.05%
Charles Schwab Corp/The	SCHW	1,752.21	95.20	166,810.43	0.45%	1.34%	0.01%	15.22%	0.07%
Sherwin-Williams Co/The	SHW	247.77	361.79	89,642.43	0.24%	0.88%	0.00%	10.95%	0.03%

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J M Smucker Co/The	SJM	106.65	115.95	12,365.87	0.03%	3.79%	0.00%	2.51%	0.00%
SLB Ltd	SLB	1,501.13	51.34	77,068.18	0.21%	2.30%	0.00%	5.03%	0.01%
Super Micro Computer Inc	SMCI	598.99	32.39	19,401.27				28.11%	
Snap-on Inc	SNA	51.91	385.22	19,997.97	0.05%	2.53%	0.00%	4.59%	0.00%
Sandisk Corp/DE	SNDK	153.39	635.36	97,456.84					
Synopsys Inc	SNPS	191.56	414.00	79,306.68	0.21%			14.46%	0.03%
Southern Co/The	SO	1,100.19	97.38	107,136.85	0.29%	3.04%	0.01%	7.18%	0.02%
Solventum Corp	SOLV	173.49	74.20	12,873.18	0.03%			9.40%	0.00%
Simon Property Group Inc	SPG	324.95	203.85	66,240.09	0.18%	4.32%	0.01%	1.62%	0.00%
S&P Global Inc	SPGI	306.00	441.88	135,215.28	0.37%	0.88%	0.00%	12.28%	0.04%
Sempra	SRE	652.68	96.27	62,833.65	0.17%	2.73%	0.00%	6.99%	0.01%
STERIS PLC	STE	98.08	252.35	24,749.23		1.00%			
Steel Dynamics Inc	STLD	144.88	193.13	27,981.14		1.10%		27.32%	
State Street Corp	STT	278.73	128.62	35,850.02	0.10%	2.61%	0.00%	9.85%	0.01%
Seagate Technology Holdings PLC	STX	218.07	407.84	88,938.92		0.73%		38.04%	
Constellation Brands Inc	STZ	173.38	157.86	27,370.50		2.58%		-1.97%	
Smurfit Westrock PLC	SW	524.25	47.01	24,645.17		3.85%		65.65%	
Stanley Black & Decker Inc	SWK	155.08	86.49	13,412.82		3.84%			
Skyworks Solutions Inc	SWKS	150.37	59.58	8,959.26		4.77%		-4.65%	
Synchrony Financial	SYF	347.60	69.11	24,022.38	0.06%	1.74%	0.00%	8.79%	0.01%
Stryker Corp	SYK	382.69	387.46	148,276.56	0.40%	0.91%	0.00%	10.60%	0.04%
Sysco Corp	SYY	478.93	91.16	43,659.32		2.37%			
AT&T Inc	T	7,000.58	28.01	196,086.17	0.53%	3.96%	0.02%	10.62%	0.06%
Molson Coors Beverage Co	TAP	175.59	48.99	8,602.28		3.92%		-4.36%	
TransDigm Group Inc	TDG	56.47	1,302.79	73,573.19	0.20%			12.68%	0.03%
Teledyne Technologies Inc	TDY	46.31	681.10	31,538.55	0.09%			8.48%	0.01%
Bio-Techne Corp	TECH	156.45	59.00	9,230.74	0.02%	0.54%	0.00%	10.00%	0.00%
TE Connectivity PLC	TEL	293.43	230.15	67,533.90	0.18%	1.23%	0.00%	13.90%	0.03%
Teradyne Inc	TER	156.56	320.03	50,102.60		0.16%		34.29%	
Truist Financial Corp	TFC	1,249.17	49.31	61,596.49	0.17%	4.22%	0.01%	13.18%	0.02%
Target Corp	TGT	452.81	113.79	51,524.84		4.01%		-1.57%	
TJX Cos Inc/The	TJX	1,110.47	161.66	179,518.11	0.49%	1.05%	0.01%	8.25%	0.04%
TKO Group Holdings Inc	TKO	77.97	223.87	17,454.32		1.39%		80.03%	
Thermo Fisher Scientific Inc	TMO	371.48	521.11	193,584.15	0.52%	0.36%	0.00%	7.12%	0.04%
T-Mobile US Inc	TMUS	1,101.86	217.09	239,203.38		1.88%			
Texas Pacific Land Corp	TPL	68.94	523.69	36,104.00		0.46%			
Tapestry Inc	TPR	202.46	155.47	31,477.11	0.09%	1.03%	0.00%	13.83%	0.01%
Targa Resources Corp	TRGP	214.95	235.80	50,685.63		2.12%		23.24%	
Trimble Inc	TRMB	233.93	66.87	15,642.86					
T Rowe Price Group Inc	TROW	218.07	94.63	20,636.24	0.06%	5.50%	0.00%	2.38%	0.00%
Travelers Cos Inc/The	TRV	216.24	308.64	66,739.67		1.43%		-1.90%	
Tractor Supply Co	TSCO	526.35	51.84	27,286.05	0.07%	1.85%	0.00%	8.35%	0.01%
Tesla Inc	TSLA	3,752.43	402.51	1,510,391.40					
Tyson Foods Inc	TSN	282.07	64.99	18,331.73	0.05%	3.14%	0.00%	11.69%	0.01%
Trane Technologies PLC	TT	221.33	462.32	102,326.17	0.28%	0.91%	0.00%	12.53%	0.03%
Trade Desk Inc/The	TTD	432.87	23.82	10,310.93	0.03%			15.40%	0.00%
Take-Two Interactive Software Inc	TTWO	185.18	211.48	39,160.91				62.23%	
Texas Instruments Inc	TXN	907.55	212.11	192,500.59	0.52%	2.68%	0.01%	14.12%	0.07%
Textron Inc	TXT	174.16	98.65	17,181.12	0.05%	0.08%	0.00%	10.14%	0.00%
Tyler Technologies Inc	TYL	42.99	354.69	15,246.47					
United Airlines Holdings Inc	UAL	327.70	106.30	34,834.92	0.09%			16.94%	0.02%
Uber Technologies Inc	UBER	2,058.12	75.42	155,223.11	0.42%			3.27%	0.01%
UDR Inc	UDR	328.57	37.50	12,321.45	0.03%	4.59%	0.00%	1.17%	0.00%
Universal Health Services Inc	UHS	53.84	205.90	11,085.22	0.03%	0.39%	0.00%	6.82%	0.00%
Ulta Beauty Inc	ULTA	44.36	684.79	30,378.77	0.08%			6.85%	0.01%
UnitedHealth Group Inc	UNH	905.84	293.27	265,655.29	0.72%	3.01%	0.02%	11.94%	0.09%
Union Pacific Corp	UNP	593.39	264.98	157,236.87	0.42%	2.08%	0.01%	8.21%	0.03%
United Parcel Service Inc	UPS	743.86	115.96	86,257.52	0.23%	5.66%	0.01%	9.01%	0.02%
United Rentals Inc	URI	63.00	840.00	52,918.45	0.14%	0.94%	0.00%	14.54%	0.02%
US Bancorp	USB	1,553.70	54.66	84,925.01	0.23%	3.81%	0.01%	11.13%	0.03%
Visa Inc	V	1,681.09	320.14	538,185.41	1.45%	0.84%	0.01%	13.86%	0.20%
VICI Properties Inc	VICI	1,068.74	30.21	32,286.55	0.09%	5.96%	0.01%	4.11%	0.00%
Valero Energy Corp	VLO	299.03	204.64	61,192.73		2.35%			
Veralto Corp	VLTO	247.84	97.43	24,147.38		0.53%			
Vulcan Materials Co	VMC	130.58	310.00	40,479.92	0.11%	0.67%	0.00%	15.26%	0.02%
Verisk Analytics Inc	VRSK	137.94	207.57	28,632.60	0.08%	0.96%	0.00%	11.03%	0.01%
VeriSign Inc	VRSN	91.70	227.94	20,902.10		1.42%			
Vertex Pharmaceuticals Inc	VRTX	254.03	496.83	126,211.81					
Vistra Corp	VST	336.95	173.89	58,592.98	0.16%	0.52%	0.00%	18.89%	0.03%
Ventas Inc	VTR	474.97	86.16	40,923.00	0.11%	2.41%	0.00%	10.72%	0.01%
Viatris Inc	VTRS	1,151.39	14.93	17,190.30	0.05%	3.22%	0.00%	3.66%	0.00%
Verizon Communications Inc	VZ	4,217.68	50.14	211,474.68		5.64%			
Westinghouse Air Brake Technologies Corp	WAB	170.52	263.95	45,008.01	0.12%	0.47%	0.00%	12.73%	0.02%
Waters Corp	WAT	98.10	319.38	31,331.78	0.08%			11.70%	0.01%
Warner Bros Discovery Inc	WBD	2,479.93	28.17	69,859.61					
Workday Inc	WDAY	213.00	133.76	28,490.88					
Western Digital Corp	WDC	339.04	279.70	94,828.91		0.18%		51.11%	
WEC Energy Group Inc	WEC	325.53	116.96	38,074.15	0.10%	3.26%	0.00%	7.05%	0.01%
Welltower Inc	WELL	697.75	207.12	144,518.50	0.39%	1.43%	0.01%	18.58%	0.07%
Wells Fargo & Co	WFC	3,085.64	81.45	251,325.02	0.68%	2.21%	0.02%	13.66%	0.09%
Waste Management Inc	WM	403.34	240.84	97,139.39	0.26%	1.37%	0.00%	9.48%	0.02%
Williams Cos Inc/The	WMB	1,221.56	74.72	91,275.20		2.81%		24.06%	
Walmart Inc	WMT	7,970.17	127.95	1,019,782.86	2.76%	0.77%	0.02%	10.27%	0.28%

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W R Berkley Corp	WRB	374.49	71.70	26,850.99	0.07%	0.50%	0.00%	5.24%	0.00%
Williams-Sonoma Inc	WSM	119.38	205.65	24,550.64	0.07%	1.28%	0.00%	4.68%	0.00%
West Pharmaceutical Services Inc	WST	72.02	254.34	18,317.95	0.05%	0.35%	0.00%	11.11%	0.01%
Willis Towers Watson PLC	WTW	94.55	305.17	28,852.57		1.26%			
Weyerhaeuser Co	WY	720.67	24.53	17,677.91		3.42%			
Wynn Resorts Ltd	WYNN	103.97	108.19	11,249.00		0.92%			
Xcel Energy Inc	XEL	623.88	83.36	52,006.37	0.14%	2.84%	0.00%	8.88%	0.01%
Exxon Mobil Corp	XOM	4,166.76	152.50	635,431.43		2.70%			
Xylem Inc/NY	XYL	243.14	129.56	31,501.40		1.33%			
Block Inc	XYZ	539.10	63.70	34,340.86				29.74%	
Yum! Brands Inc	YUM	276.43	168.16	46,484.49	0.13%	1.78%	0.00%	8.99%	0.01%
Zimmer Biomet Holdings Inc	ZBH	195.65	98.44	19,259.98	0.05%	0.98%	0.00%	5.83%	0.00%
Zebra Technologies Corp	ZBRA	49.19	223.96	11,016.97					
Zoetis Inc	ZTS	422.13	131.10	55,340.94	0.15%	1.62%	0.00%	9.00%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional, as of February 28, 2026
[5] Bloomberg Professional, as of February 28, 2026
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Bloomberg Professional, as of February 28, 2026
[9] Equals [7] x [8]
[10] Bloomberg Professional, as of February 28, 2026
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.906462547
R Square	0.821674348
Adjusted R Square	0.820699891
Standard Error	0.005798105
Observations	185

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.02834713	0.02834713	843.2124283	1.98759E-70
Residual	183	0.006152097	3.3618E-05		
Total	184	0.034499227			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07847694	0.000953811	82.27721571	1.7139E-146	0.076595059	0.080358821	0.076595059	0.080358821
X Variable 1	-0.412081653	0.014191058	-29.03812026	1.98759E-70	-0.44008078	-0.384082526	-0.44008078	-0.384082526

	[7] 30-Year Treasury Yield [7]	[8] Risk Premium [8]	[9] ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.79%	5.87%	10.66%
Blue Chip Near-Term Projected Forecast (Q2 2026 - Q2 2027) [5]	4.76%	5.89%	10.65%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.60%	5.95%	10.55%
AVERAGE			10.62%

Notes:
[1] Regulatory Research Associates, rate cases through December 31, 2025
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Bloomberg Professional 30-day average as of February 28 2026
[5] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 2
[6] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.078477 + (-0.412082 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.91%	10.55%	4.36%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%

BOND YIELD PLUS RISK PREMIUM

1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	10.88%	5.70%	5.17%
2001.3	10.76%	5.53%	5.23%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.25%	5.09%	6.16%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.85%	6.57%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.76%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	10.91%	4.93%	5.98%
2005.1	10.56%	4.71%	5.85%
2005.2	10.13%	4.47%	5.65%
2005.3	10.85%	4.42%	6.42%
2005.4	10.59%	4.65%	5.94%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	5.00%	5.07%
2006.4	10.39%	4.74%	5.64%
2007.1	10.39%	4.80%	5.59%
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.81%
2008.1	10.15%	4.41%	5.74%
2008.2	10.54%	4.57%	5.96%
2008.3	10.38%	4.45%	5.93%
2008.4	10.39%	3.64%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.41%
2009.3	10.41%	4.32%	6.09%
2009.4	10.54%	4.34%	6.20%
2010.1	10.45%	4.62%	5.82%
2010.2	10.08%	4.37%	5.71%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%
2011.3	10.36%	3.70%	6.66%
2011.4	10.34%	3.04%	7.31%

BOND YIELD PLUS RISK PREMIUM

2012.1	10.30%	3.14%	7.17%
2012.2	9.92%	2.94%	6.98%
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.04%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.27%	6.52%
2014.4	9.78%	2.96%	6.81%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.61%
2015.3	9.40%	2.96%	6.44%
2015.4	9.65%	2.96%	6.69%
2016.1	9.70%	2.72%	6.98%
2016.2	9.41%	2.57%	6.84%
2016.3	9.76%	2.28%	7.48%
2016.4	9.55%	2.83%	6.72%
2017.1	9.61%	3.05%	6.57%
2017.2	9.61%	2.90%	6.71%
2017.3	9.73%	2.82%	6.91%
2017.4	9.74%	2.82%	6.92%
2018.1	9.59%	3.02%	6.57%
2018.2	9.57%	3.09%	6.49%
2018.3	9.66%	3.06%	6.60%
2018.4	9.44%	3.27%	6.17%
2019.1	9.57%	3.01%	6.55%
2019.2	9.58%	2.78%	6.79%
2019.3	9.57%	2.29%	7.28%
2019.4	9.74%	2.26%	7.49%
2020.1	9.45%	1.89%	7.56%
2020.2	9.52%	1.38%	8.14%
2020.3	9.34%	1.37%	7.98%
2020.4	9.32%	1.62%	7.70%
2021.1	9.45%	2.07%	7.38%
2021.2	9.53%	2.26%	7.27%
2021.3	9.37%	1.93%	7.43%
2021.4	9.37%	1.95%	7.42%
2022.1	9.34%	2.25%	7.08%
2022.2	9.61%	3.05%	6.56%
2022.3	9.14%	3.26%	5.88%
2022.4	9.72%	3.89%	5.83%
2023.1	9.71%	3.75%	5.96%
2023.2	9.81%	3.81%	6.00%
2023.3	9.63%	4.23%	5.40%
2023.4	9.66%	4.58%	5.08%
2024.1	9.66%	4.32%	5.34%
2024.2	9.91%	4.58%	5.33%
2024.3	9.78%	4.23%	5.55%
2024.4	9.85%	4.50%	5.35%
2025.1	9.73%	4.72%	5.01%
2025.2	9.95%	4.84%	5.11%
2025.3	9.54%	4.85%	4.70%
2025.4	9.83%	4.71%	5.11%
2026.1	9.72%	4.80%	4.92%

PROJECTED CAPITAL EXPENDITURES AS A PERCENTAGE OF NET PLANT
($ Millions)

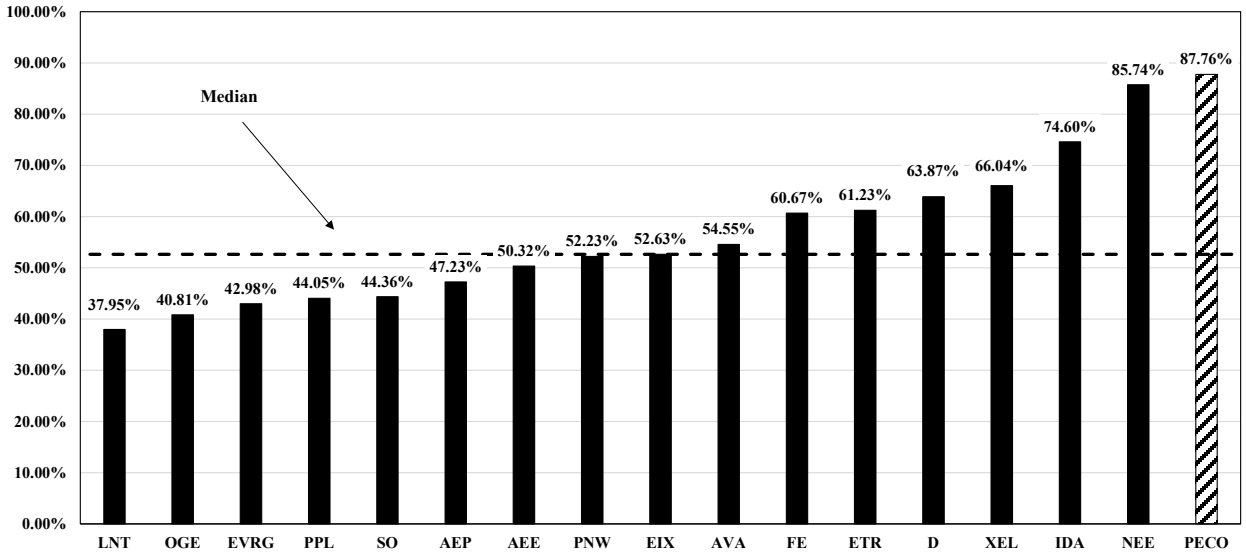
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2025	2026	2027	2028	2029	2030	Projected Cap. Ex. / Net Plant
Alliant Energy Corporation	LNT							
Capital Spending per Share			$ 5.60	$ 5.50	$ 5.40	$ 5.40	$ 5.40	
Common Shares Outstanding			258	258	259	259	259	
Capital Expenditures			$ 1,442.00	$ 1,420.38	$ 1,398.60	$ 1,398.60	$ 1,398.60	37.95%
Net Plant		$ 18,600						
Ameren Corporation	AEE		$ 12.85	$ 12.93	$ 13.00	$ 13.00	$ 13.00	
Capital Spending per Share			275	280	285	285	285	
Common Shares Outstanding			$ 3,533.75	$ 3,619.00	$ 3,705.00	$ 3,705.00	$ 3,705.00	50.32%
Capital Expenditures		$ 36,300						
Net Plant								
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$ 14.10	$ 14.05	$ 14.00	$ 14.00	$ 14.00	
Common Shares Outstanding			540	545	550	550	550	
Capital Expenditures			$ 7,614.00	$ 7,657.25	$ 7,700.00	$ 7,700.00	$ 7,700.00	47.23%
Net Plant		$ 81,250						
Avista Corporation	AVA							
Capital Spending per Share			$ 6.45	$ 7.00	$ 8.25	$ 9.50	$ 9.50	
Common Shares Outstanding			82	83	84	85	85	
Capital Expenditures			$ 525.68	$ 581.00	$ 693.00	$ 807.50	$ 807.50	54.55%
Net Plant		$ 6,260						
Dominion Resources, Inc.	D							
Capital Spending per Share			$ 12.75	$ 10.50	$ 10.75	$ 11.00	$ 11.00	
Common Shares Outstanding			870	865	898	930	930	
Capital Expenditures			$ 11,092.50	$ 9,082.50	$ 9,648.13	$ 10,230.00	$ 10,230.00	63.87%
Net Plant		$ 78,725						
Edison International	EIX							
Capital Spending per Share			$ 16.30	$ 16.80	$ 16.90	$ 17.00	$ 17.00	
Common Shares Outstanding			385	388	392	395	395	
Capital Expenditures			$ 6,275.50	$ 6,518.40	$ 6,616.35	$ 6,715.00	$ 6,715.00	52.63%
Net Plant		$ 62,400						
Entergy Corporation	ETR							
Capital Spending per Share			$ 12.50	$ 13.25	$ 14.00	$ 14.00	$ 14.00	
Common Shares Outstanding			440	450	460	460	460	
Capital Expenditures			$ 5,500.00	$ 5,962.50	$ 6,440.00	$ 6,440.00	$ 6,440.00	61.23%
Net Plant		$ 50,270						
Evergy, Inc.	EVRG							
Capital Spending per Share			$ 9.35	$ 9.43	$ 9.50	$ 9.50	$ 9.50	
Common Shares Outstanding			230	230	230	230	230	
Capital Expenditures			$ 2,150.50	$ 2,167.75	$ 2,185.00	$ 2,185.00	$ 2,185.00	42.98%
Net Plant		$ 25,300						
FirstEnergy Corporation	FE							
Capital Spending per Share			$ 8.40	$ 9.50	$ 9.25	$ 9.00	$ 9.00	
Common Shares Outstanding			585	590	598	605	605	
Capital Expenditures			$ 4,914.00	$ 5,605.00	$ 5,526.88	$ 5,445.00	$ 5,445.00	60.67%
Net Plant		$ 44,400						
IDACORP, Inc.	IDA							
Capital Spending per Share			$ 20.00	$ 19.75	$ 19.75	$ 19.75	$ 19.75	
Common Shares Outstanding			55	56	56	56	56	
Capital Expenditures			$ 1,100.00	$ 1,096.13	$ 1,101.06	$ 1,106.00	$ 1,106.00	74.60%
Net Plant		$ 7,385						
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$ 12.00	$ 12.25	$ 12.38	$ 12.50	$ 12.50	
Common Shares Outstanding			2110	2135	2178	2220	2220	
Capital Expenditures			$ 25,320.00	$ 26,153.75	$ 26,946.56	$ 27,750.00	$ 27,750.00	85.74%
Net Plant		$ 156,197						
OGE Energy Corporation	OGE							
Capital Spending per Share			$ 4.75	$ 4.75	$ 4.75	$ 4.75	$ 4.75	
Common Shares Outstanding			200	200	200	200	200	
Capital Expenditures			$ 950.95	$ 950.95	$ 950.95	$ 950.95	$ 950.95	40.81%
Net Plant		$ 11,650						

PROJECTED CAPITAL EXPENDITURES AS A PERCENTAGE OF NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2025	2026	2027	2028	2029	2030	Projected Cap. Ex. / Net Plant
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$ 16.75	$ 17.00	$ 17.25	$ 17.50	$ 17.50	
Common Shares Outstanding			120	121	123	125	125	
Capital Expenditures			$ 2,010.00	$ 2,057.00	$ 2,121.75	$ 2,187.50	$ 2,187.50	52.23%
Net Plant		$ 20,225						
PPL Corporation	PPL							
Capital Spending per Share			$ 3.75	$ 3.85	$ 3.93	$ 4.00	$ 4.00	
Common Shares Outstanding			738	738	738	738	738	
Capital Expenditures			$ 2,765.63	$ 2,839.76	$ 2,895.87	$ 2,952.00	$ 2,952.00	44.05%
Net Plant		$ 32,700						
Southern Company	SO							
Capital Spending per Share			$ 8.70	$ 6.65	$ 7.58	$ 8.50	$ 8.50	
Common Shares Outstanding			1110	1115	1118	1120	1120	
Capital Expenditures			$ 9,657.00	$ 7,414.75	$ 8,465.06	$ 9,520.00	$ 9,520.00	44.36%
Net Plant		$ 100,500						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$ 17.50	$ 13.50	$ 13.25	$ 13.00	$ 13.00	
Common Shares Outstanding			592	594	597	600	600	
Capital Expenditures			$ 10,353.00	$ 8,012.25	$ 7,906.94	$ 7,800.00	$ 7,800.00	66.04%
Net Plant		$ 63,400						
PECO Energy - Electric Division	PECO							
Capital Expenditures [8]			$ 1,826.00	$ 1,948.00	$ 1,966.00	$ 2,009.00	$ 2,020.00	87.76%
Net Plant [9]		$ 11,132.00						

Notes:
[1] - [6] Value Line, dated December 5, 2025, January 16, 2026, and February 6, 2026.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Provided by the Company
[9] Provided by the Company

PROJECTED CAPITAL EXPENDITURES AS A PERCENTAGE OF NET PLANT



	Company		Projected CAPEX / Net Plant
1	Alliant Energy Corporation	LNT	37.95%
2	OGE Energy Corporation	OGE	40.81%
3	Evergy, Inc.	EVRG	42.98%
4	PPL Corporation	PPL	44.05%
5	Southern Company	SO	44.36%
6	American Electric Power Company, Inc.	AEP	47.23%
7	Ameren Corporation	AEE	50.32%
8	Pinnacle West Capital Corporation	PNW	52.23%
9	Edison International	EIX	52.63%
10	Avista Corporation	AVA	54.55%
11	FirstEnergy Corporation	FE	60.67%
12	Entergy Corporation	ETR	61.23%
13	Dominion Resources, Inc.	D	63.87%
14	Xcel Energy Inc.	XEL	66.04%
15	IDACORP, Inc.	IDA	74.60%
16	NextEra Energy, Inc.	NEE	85.74%
17	PECO Energy - Electric Division	PECO	87.76%

Proxy Group Median	52.63%
PECO as % of Median	1.15

Notes:
PECO Exhibit AEB-9, p. 1, col. [7]

REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]
					Revenue Stabilization				
Proxy Group Company	**Operating Subsidiary**	**Jurisdiction**	**Service**	**Test Year**	**Revenue Decoupling**	**Formula-Based Rates**	**Straight Fixed-Variable Rate Design**	**Overall Revenue Stabilization**	**Capital Cost Recovery**
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Fully Forecast	No	No	No	No	Yes
	Interstate Power & Light Co.	Iowa	Gas	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Yes	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Yes	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Historical	No	No	No	No	No
	AEP Texas Inc.	Texas	Electric	Historical	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	Yes
Avista Corporation	Alaska Electric Light & Power Co.	Alaska	Electric	Historical	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	No
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	No
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	No
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	No
Dominion Resources, Inc.	Dominion Energy Virginia	North Carolina	Electric	Historical	Yes	No	No	Yes	Yes
	Dominion Energy South Carolina	South Carolina	Electric	Historical	No	No	No	No	Yes
	Dominion Energy South Carolina	South Carolina	Gas	Historical	Yes	No	No	Yes	Yes
	Dominion Energy Virginia	Virginia	Electric	Partially Forecast	No	No	No	No	Yes
Edison International	Southern California Edison Co.	California	Electric	Fully Forecast	Yes	No	No	Yes	No
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	Yes	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	No
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Yes	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	No	Yes	No	Yes	No
	Entergy Texas Inc.	Texas	Electric	Historical	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes
FirstEnergy Corporation	Potomac Edison Co.	Maryland	Electric	Historical	No	No	No	No	No
	Jersey Central Power & Light Co.	New Jersey	Electric	Partially Forecast	Yes	No	No	Yes	Yes
	Cleveland Elec. Illum./Ohio Edison/Toledo Edison	Ohio	Electric	Partially Forecast	Yes	No	Yes	Yes	Yes
	Metropolitan Edison Co.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes
	Pennsylvania Electric Co.	Pennsylvania	Electric	Fully Forecast	Yes	No	No	Yes	Yes
	Pennsylvania Power Co.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes
	West Penn Power Co.	Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes
	Monongahela Power Co.	West Virginia	Electric	Historical	No	No	No	No	Yes
	Potomac Edison Co.	West Virginia	Electric	Historical	No	No	No	No	No
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Yes	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	No	No	No	No	Yes

REGULATORY RISK ASSESSMENT

Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Test Year [1]	Revenue Stabilization [2] Revenue Decoupling	[3] Formula-Based Rates	[4] Straight Fixed-Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
	Lone Star Transmission LLC	Texas	Electric	Historical	No	No	No	No	Yes
OGE Energy Corporation	Oklahoma Gas & Electric	Arkansas	Electric	Historical	Yes	Yes	No	Yes	Yes
	Oklahoma Gas & Electric	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes
Pinnacle West Capital Corporation	Arizona Public Service Co.	Arizona	Electric	Historical	Yes	No	No	Yes	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Historical	No	Yes	No	Yes	Yes
	Atlanta Gas Light Co.	Georgia	Electric	Fully Forecast	No	No	No	No	Yes
	Georgia Power Co.	Georgia	Gas	Fully Forecast	Yes	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	No	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Yes	Yes	No	Yes	No
	Virginia Natural Gas Inc.	Virginia	Gas	Partially Forecast	Yes	No	Yes	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Yes	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	No	No	No	No	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No
Proxy Group Average				Fully Forecast 29			Yes	47	Yes 54
				Partially Forecast 9			No	30	No 23
				Historical 39					
			% with ForecastTest Year:	49.4%			% with Form of Revenue Stabilization	61.0%	% with Form of Capital Cost Recovery 70.1%
PECO Energy - Electric Division [7]		Pennsylvania	Electric	Fully Forecast	No	No	No	No	Yes

Notes:

[1] Regulatory Research Associates, effective as of February 28, 2026.

[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September, 2025. Operating subsidiaries not covered in this report were excluded from this exhibit. Designated "Yes" if full or partial decoupling.

[3] S&P Capital IQ Pro, Alternative Regulation

[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025.

[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)

[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 2025. Designated "Yes" if noted by S&P as a having a capital tracker to recover either "Traditional generation", "Renewables/Non-traditional generation", "Delivery infrastructure", or "Environmental compliance".

[7] Company Provided Data.

RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
		Rank	Numeric Rank
Alliant Energy Corporation	Iowa	Above Average/3	3
	Wisconsin	Above Average/3	3
Ameren Corporation	Illinois	Average/3	6
	Missouri	Average/2	5
American Electric Power Company, Inc.	Arkansas	Average/1	4
	Indiana	Average/1	4
	Kentucky	Average/2	5
	Louisiana — PSC	Average/2	5
	Michigan	Average/1	4
	Ohio	Average/1	4
	Oklahoma	Average/3	6
	Tennessee	Above Average/3	3
	Texas — PUC	Below Average/1	7
	Virginia	Average/1	4
	West Virginia	Below Average/1	7
Avista Corporation	Alaska	Below Average/1	7
	Idaho	Average/2	5
	Oregon	Average/3	6
	Washington	Average/3	6
Dominion Resources, Inc.	North Carolina	Above Average/3	3
	South Carolina	Average/2	5
	Virginia	Average/1	4
Edison International	California	Average/2	5
Entergy Corporation	Arkansas	Average/1	4
	Louisiana — NOCC	Average/3	6
	Louisiana — PSC	Average/2	5
	Mississippi	Above Average/3	3
	Texas — PUC	Below Average/1	7
Evergy, Inc.	Kansas	Average/3	6
	Missouri	Average/2	5
FirstEnergy Corporation	Maryland	Below Average/3	9
	New Jersey	Average/3	6
	Ohio	Average/1	4
	Pennsylvania	Above Average/2	2
	West Virginia	Below Average/1	7
IDACORP, Inc.	Idaho	Average/2	5
	Oregon	Average/3	6
NextEra Energy, Inc.	Florida	Above Average/2	2
	Texas — PUC	Below Average/1	7
OGE Energy Corporation	Arkansas	Average/1	4
	Oklahoma	Average/3	6
Pinnacle West Capital Corporation	Arizona	Below Average/2	8
Southern Company	Alabama	Above Average/1	1
	Georgia	Above Average/2	2
	Illinois	Average/3	6
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Virginia	Average/1	4
Xcel Energy Inc.	Colorado	Average/1	4
	Minnesota	Average/2	5
	New Mexico	Below Average/1	7
	North Dakota	Average/1	4
	South Dakota	Average/2	5
	Texas — PUC	Below Average/1	7
	Wisconsin	Above Average/3	3
Proxy Group Average		Average / 1 - Average / 2	4.85
PECO Energy - Electric Division	Pennsylvania	Above Average/2	2.00

Notes
[1] State Regulatory Evaluations, Regulatory Research Associates, December 29, 2025.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
Alliant Energy Corporation	Iowa	Most credit supportive	1
	Wisconsin	Most credit supportive	1
Ameren Corporation	Illinois	Very credit supportive	3
	Missouri	Highly credit supportive	2
American Electric Power Company, Inc.	Arkansas	Highly credit supportive	2
	Indiana	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Louisiana — PSC	Highly credit supportive	2
	Michigan	Most credit supportive	1
	Ohio	Very credit supportive	3
	Oklahoma	Very credit supportive	3
	Tennessee	Highly credit supportive	2
	Texas — PUC	Very credit supportive	3
	Virginia	Highly credit supportive	2
	West Virginia	Very credit supportive	3
Avista Corporation	Alaska	More credit supportive	4
	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
	Washington	Very credit supportive	3
Dominion Resources, Inc.	North Carolina	Highly credit supportive	2
	South Carolina	Very credit supportive	3
	Virginia	Highly credit supportive	2
Edison International	California	More credit supportive	4
Entergy Corporation	Arkansas	Highly credit supportive	2
	Louisiana — NOCC	More credit supportive	4
	Louisiana — PSC	Highly credit supportive	2
	Mississippi	Highly credit supportive	2
	Texas — PUC	Very credit supportive	3
Evergy, Inc.	Kansas	Highly credit supportive	2
	Missouri	Highly credit supportive	2
FirstEnergy Corporation	Maryland	Very credit supportive	3
	New Jersey	More credit supportive	4
	Ohio	Very credit supportive	3
	Pennsylvania	Highly credit supportive	2
	West Virginia	Very credit supportive	3
IDACORP, Inc.	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
NextEra Energy, Inc.	Florida	Most credit supportive	1
	Texas — PUC	Very credit supportive	3
OGE Energy Corporation	Arkansas	Highly credit supportive	2
	Oklahoma	Very credit supportive	3
Pinnacle West Capital Corporation	Arizona	Very credit supportive	3
Southern Company	Alabama	Most credit supportive	1
	Georgia	Highly credit supportive	2
	Illinois	Very credit supportive	3
	Mississippi	Highly credit supportive	2
	Tennessee	Highly credit supportive	2
	Virginia	Highly credit supportive	2
Xcel Energy Inc.	Colorado	Very credit supportive	3
	Minnesota	Highly credit supportive	2
	New Mexico	Credit Supportive	5
	North Dakota	Highly credit supportive	2
	South Dakota	Very credit supportive	3
	Texas — PUC	Very credit supportive	3
	Wisconsin	Most credit supportive	1
Proxy Group Average		Highly Credit Supportive / Very Credit Supportive	2.51
PECO Energy - Electric Division	Pennsylvania	Highly credit supportive	2.00

Notes

[1] North American Utilities Regulatory Jurisdictions Update: South Carolina Assessment Revised; Other Notable Developments, Standard and Poor's Ratings Services, November 4, 2025.

[2] Most= 1, Highly= 2, Very= 3, More= 4, Credit Supportive= 5

CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2025Q3 - 2023Q4)			
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Total Capitalization
Alliant Energy Corporation	LNT	51.99%	48.01%	0.00%	100.00%
Ameren Corporation	AEE	53.29%	46.25%	0.46%	100.00%
American Electric Power Company, Inc.	AEP	48.95%	51.05%	0.00%	100.00%
Avista Corporation	AVA	50.11%	49.89%	0.00%	100.00%
Dominion Resources, Inc.	D	54.29%	45.71%	0.00%	100.00%
Edison International	EIX	38.22%	57.14%	4.64%	100.00%
Entergy Corporation	ETR	50.84%	49.07%	0.09%	100.00%
Evergy, Inc.	EVRG	60.01%	39.99%	0.00%	100.00%
FirstEnergy Corporation	FE	59.61%	40.39%	0.00%	100.00%
IDACORP, Inc.	IDA	49.11%	50.89%	0.00%	100.00%
NextEra Energy, Inc.	NEE	60.14%	39.86%	0.00%	100.00%
OGE Energy Corporation	OGE	53.29%	46.71%	0.00%	100.00%
Pinnacle West Capital Corporation	PNW	51.52%	48.48%	0.00%	100.00%
Portland General Electric Company	POR	44.83%	55.17%	0.00%	100.00%
PPL Corporation	PPL	56.19%	43.81%	0.00%	100.00%
Southern Company	SO	55.63%	44.37%	0.00%	100.00%
Xcel Energy Inc.	XEL	53.87%	46.13%	0.00%	100.00%
	Average	52.46%	47.23%	0.31%	
	Median	53.29%	46.71%	0.00%	
	Maximum	60.14%	57.14%	4.64%	
	Minimum	38.22%	39.86%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, and long-term debt of the operating subsidiaries.
[2] Electric and Natural Gas operating subsidiaries with data listed as N/A from S&P Capital IQ have been excluded fr

PECO Statement No. 8:
Direct Testimony of Jiang Ding

PECO ENERGY COMPANY
STATEMENT NO. 8

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: JIANG DING

SUBJECT: CLASS COST-OF-SERVICE STUDY

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
JIANG DING

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Jiang Ding. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Principal Regulatory & Rates Specialist.

3. Q. Please describe your educational background.

A. I received a Bachelor's Degree in Law from China University of Political Science and Law, and I received a Master of Science Degree in Finance from Texas A&M University.

4. Q. Please describe your work experience with the energy industry.

A. Upon graduation from Texas A&M University, I worked as an Accountant for Enron and as a Financial Analyst for Halliburton Energy Services. I was hired by Exelon Power as an Operational Area Analyst in 2002. I then worked for Exelon Generation and Exelon Corporation as a Senior Project Evaluation Analyst. I was appointed Principal Regulatory & Rates Specialist in PECO's Regulatory Strategy and Revenue Policy Division in 2013. My main responsibilities include revenue requirement modeling and analyses for regulatory initiatives, cost-of-service studies, and base rate case filings.

5. Q. Please describe the purpose of your testimony.

A. I will explain the cost-of-service principles underlying the unbundled, fully allocated class cost-of-service study ("COSS") that I performed, the methods and procedures employed to perform such study, and the results produced by the COSS.

6. Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. PECO Exhibits JD-1 to JD-9 were prepared and are described in detail in my testimony.

7. Q. How is your testimony organized?

A. My testimony is divided into four parts. First, I provide some background information, identify the exhibits that I am sponsoring, and summarize the results of the COSS. Second, I introduce and discuss the COSS methodology. Third, I explain the development of the revenue requirement for each rate class. Fourth, I present the results of the COSS in detail and discuss the contents of the exhibits.

8. Q. Please identify the exhibits that are included with your direct testimony.

A. The following exhibits are included with my testimony. They are discussed in greater detail in Section IV of my testimony.

PECO Exhibit JD-1	Summary of Results and Revenue Requirement by Rate Class
PECO Exhibit JD-2	Total Class Allocation – Allocator Development
PECO Exhibit JD-3	Revenue Requirement by Functional Classification
PECO Exhibit JD-4	Unitized Functionally Classified Revenue Requirement
PECO Exhibit JD-5	Customer-Related Revenue Requirement and Customer Charge
PECO Exhibit JD-6	Night Service Rider-Related Costs
PECO Exhibit JD-7	Development of External Allocation Factors

PECO Exhibit JD-8	Development of Unbundled Cash Working Capital Rate for the Generation Supply Adjustment
PECO Exhibit JD-9	Development of Unbundled Cash Working Capital Rate for the Transmission Service Charge

II. BACKGROUND INFORMATION AND SUMMARY OF COST-OF-SERVICE STUDY RESULTS

9. Q. What is the total revenue requirement you used to prepare PECO's COSS?

A. I used the total distribution revenue requirement for the fully projected future test year ("FPFTY") developed in PECO Exhibit MJT-1, which is sponsored by PECO witness Michael J. Trzaska and discussed in Mr. Trzaska's direct testimony ((Statement No. 4). The total distribution revenue requirement for the FPFTY is $2.459 billion (PECO Exhibit JD-1, page 2, line 55) excluding costs recovered under PECO's Generation Supply Adjustment ("GSA")[1] and Transmission Service Charge ("TSC")[2] and $4.319 billion (PECO Exhibit JD-1, page 2, line 99) including costs recovered under the GSA and TSC. The total distribution revenues and distribution revenues by customer class for the FPFTY under existing rates that are used in the COSS were also obtained from PECO Exhibit MJT-1, and in the proof of revenues set forth in PECO Exhibit JAB-3.

[1] The GSA is the reconcilable rate adjustment that recovers, on a bypassable basis, the costs PECO incurs to provide default service to customers that do not obtain generation from an electric generation supplier.

[2] The TSC is the reconcilable rate adjustment that recovers charges for network transmission service incurred by PECO on a bypassable basis from PECO's default service customers. PJM Interconnection, L.L.C. ("PJM") furnishes network transmission service to PECO pursuant to the PJM Open Access Transmission Tariff.

10. Q. Please summarize the results of the COSS as they pertain to changes in rates proposed in PECO's filing.

A. The results of the COSS and my conclusions based on those results are as follows:

1. The current tariff rates produce the net income by rate class shown on page 1, line 15 of PECO Exhibit JD-1, which yields the rates of return on rate base shown on line 22 of that page. The table below summarizes these results.

Rate Class	ROR	Ratio to Average ROR
R	5.57%	1.03
RH	3.42%	0.63
GS	6.02%	1.11
PD	6.52%	1.20
HT	5.87%	1.08
EP	3.05%	0.56
Lighting	7.44%	1.37
Average	5.41%	

2. PECO's total distribution revenue requirement for the FPFTY has been allocated or assigned among the rate classes based on the results of the COSS. The results of the COSS are summarized on pages 1-3 of PECO Exhibit JD-1, which show the total distribution revenue requirement separately for distribution, transmission, and purchased power costs.

3. The increases or (decreases) in revenue by rate class needed to produce rates of return by class equal to the Company's proposed overall rate of return are shown on line 105 of page 3 of PECO Exhibit JD-1. The increases or (decreases) in revenue shown on line 105 are shown separately for

distribution base rates (line 61) and the working capital revenue requirement recovered in the TSC (line 84) and in the GSA (line 73) on page 2 of PECO Exhibit JD-1. While the summary on pages 1-3 of PECO Exhibit JD-1 shows the rate increases or (decreases) necessary to move each class to the system average rate of return, the Company is not proposing rates that will take all classes to their indicated cost of service at this time, as explained in the direct testimony of PECO witness Joseph A. Bisti (Statement No. 9).

III. PECO'S CLASS COST-OF-SERVICE STUDY

11. Q. Briefly describe the purpose of a class COSS.

A. The purpose of a COSS is to determine the cost to serve, expressed as revenue requirement, for each rate class served by a utility. The revenue requirement for a rate class is that portion of a utility's total cost of service attributed to that rate class in accordance with principles of cost causation. In a COSS, all of the utility's costs of providing service must be analyzed and assigned or allocated among the rate classes. The COSS is used, along with other factors, as discussed in more detail by Mr. Bisti, to design rates that fully recover the utility's costs.

12. Q. What are the guiding principles for performing a class COSS?

A. The central element in performing a COSS is the determination of allocation factors based on causal relationships between, on the one hand, customer demands, load profiles, and usage characteristics, and, on the other hand, the costs incurred by the Company to meet customers' service requirements imposed by those demands, load profiles, and usage characteristics. The primary goals in selecting allocation factors are: (1) the appropriate recognition of cost causality; (2) the stability of study methods and their consistent application over time, so that trends in the direction of

class revenues relative to cost of service can be discerned properly from case to case; and (3) completeness, such that the COSS captures all the costs that each class imposes on the distribution system.

13. Q. What rate classes are included in the PECO COSS?

A. The rate classes included in the PECO COSS are Residential (rate R), Residential Heating (rate RH), General Service (rate GS), Primary Distribution (rate PD), High Tension (rate HT), Electric Propulsion (rate EP), and Lighting. In the COSS, all the Lighting rate schedules in PECO's current tariff are combined into a single Lighting class, because their cost and usage characteristics are very similar. The separate classes consist of Private Outdoor Lighting (POL), Street Lighting-Suburban (SL-S), Street Lighting-Customer-Owned (SL-E), Traffic Lighting Constant Load Service (TLCL), Alley Lighting (AL), and Smart Lighting Control (SL-C).

For customers participating in PECO's Customer Assistance Program ("CAP"), the current CAP Residential (CAP-R) rate class is combined with the Residential class, because their usage characteristics are the same, and CAP-R rates are designed with reference to Residential rates. For the same reasons, the current CAP Residential Heating (CAP-RH) rate class is combined with the Residential Heating class.

14. Q. Have you considered combining rate R and rate RH for purposes of the COSS?

A. No, because it leads to inappropriate cross subsidization between the two residential rate classes and the other rate classes. Customers served on rate RH and those served only on rate R are not evenly situated throughout PECO's service territory.

There are many developments served on PECO's distribution system that were built entirely with, and retain, electric home heating. In those instances, and others, rate RH customers are concentrated on specific localized distribution facilities. The non-coincident peak ("NCP") demands of those rate RH customers reflect the peaks they impose on the localized facilities that serve them, and those winter peaks are driving the need for capacity in those localized areas. Combining rate R and rate RH into a single customer class for a cost-of-service analysis effectively ignores the rate RH winter peaks. Doing so also ignores the cost causation factor that is driving capacity needs in those localized areas where rate RH customers receive service and results in the subsidization of rate RH.

15. Q. Please summarize the approach you used in preparing PECO's COSS.

A. As I previously explained, the most critical task in performing any COSS is establishing relationships between customer demands, load profiles, and usage characteristics, and the costs incurred to meet those customer requirements. This requires an understanding of the design of the utility's distribution system and how that design relates to the characteristics of the customers it is designed to serve.

PECO, like most electric utilities, designs its electric distribution system to meet three primary objectives:

1. Connect all customers to the grid;
2. Deliver sufficient electricity to meet the aggregate peak demand for electricity of all delivery customers whenever those peaks occur; and
3. Ensure that electricity is delivered to customers safely and reliably throughout the year.

The allocation methods used in a COSS must take into account the objectives that the distribution system is designed to achieve so that the allocation of plant investment and operating expenses properly aligns with cost-causation factors such as the need to connect all customers to the distribution system and to meet class peak demands whenever they occur. Other factors, such as incentives to influence customer behavior (e.g., conservation or demand reduction) or to temper the impact on customers of rate changes, are more appropriately considered in the revenue allocation and rate design phase.

The PECO COSS I prepared was performed using the Electric Cost of Service Model ("Model") developed by Concentric Energy Advisors, which employs a Microsoft Excel platform. The Model facilitates the preparation of the COSS, accelerates computations, and develops appropriate documentation. The Model uses a three-step process to allocate or assign costs to rate classes, in accordance with general cost of service principles. These three steps consist of: (1) functionalizing rate base and costs to determine the particular rate schedules that should share responsibility for each of those assets and costs; (2) classifying functionalized costs into demand-related, energy-related, and customer-related cost categories to facilitate allocating such costs to rate schedules in accordance with identifiable characteristics; and (3) allocating the functionalized, classified costs among rate classes. The Model provides functionalized, classified cost information by rate class, develops unbundled revenue requirements by functional classification and in total for each rate class, and calculates unit costs.

16. Q. Is the Company filing the same COSS model in the instant case that was presented in PECO's most recent electric base rate proceeding (Docket No. R-2024-3046931)?

A. No. The model that was used by the Company in the COSS presented in PECO's most recent electric base rate proceeding (Docket No. R-2024-3046931) was developed by Management Applications Consulting, Inc., which ceased to operate in 2025.

17. Q. Does the Model developed by Concentric Energy Advisors produce the same results as the COSS model presented in PECO's most recent electric base rate proceeding (Docket No. R-2024-3046931)?

A. Yes. Given the same inputs, the two models will produce the exact same results. The Model also generally maintains the format of the presentation of results that the previous version employed. The Model, while producing the same results as the previous version, is entirely contained in a single Excel file and is customizable, and all of its formulas are accessible for review in the cells of the worksheets.

18. Q. Please describe the functions included in the COSS.

A. The COSS includes the following functions:

Energy: This function includes purchased power and related default service costs incurred by the Company that are recovered under its GSA, which applies to default service.

Transmission: This function includes costs associated with the Company's bulk transmission system, which is designed to move power from generation sources to the primary distribution system and operates at voltages of 69 kV and above. These

costs are generally recovered in the TSC and the Non-Bypassable Transmission Rider ("NBT").[3] The working capital included in this function only applies to the bypassable portion of the TSC cost.

Primary Distribution High Tension ("Primary HT"): This function includes costs associated with moving power from the transmission system to the Primary Distribution system, including substations that transform power from 69 kV to 34 kV or 13 kV and from 34 kV to 13 kV, conductors operating primarily at voltages between 13 kV and 34 kV, and related assets. This includes some facilities operating at voltages of 69 kV and above that are distribution facilities.

Primary Distribution ("Primary"): This function includes costs associated with moving power from the Primary HT system to the primary distribution system, including transformers that reduce voltage from 13 kV to 4 kV or 2.4 kV, conductors operating at voltages between 2.4 kV and 4 kV, and related assets.

Secondary Distribution Customer and Demand ("Secondary Distribution"): This function includes costs associated with moving power from the Primary system to customers' premises, including costs related to conductors operating at secondary voltage.

Distribution Transformers: This function includes the secondary transformers that reduce the voltage from primary power levels to levels at which secondary voltage customers receive service.

Meters: This function includes the cost to meter customers' usage and demand.

[3] The NBT is the reconcilable rate adjustment that recovers PJM charges for Regional Transmission Expansion Plan ("RTEP"), Expansion Cost Recovery, and certain Generation Deactivation / Reliability Must Run charges on a non-bypassable basis from all of PECO's distribution customers.

Services: This function includes the investment in, and operating and maintenance expenses related to, the service lines from the Company's distribution conductors to customer locations.

Customer Accounts: This function includes the cost of customer billing and records, the call center, collection of customer accounts, and uncollectible accounts.

Customer Service: This function includes costs incurred to provide energy efficiency education, educational advertising, and conservation-related service.

Customer Other: This function includes costs not included elsewhere, such as street lighting and customer deposits.

19. Q. Please describe the classification step of a COSS.

A. In the classification step, the previously functionalized assets and costs are separated into customer, energy, or demand classifications according to the system design or operating characteristics that cause those costs to be incurred.

Customer-related costs are the expenditures made to attach a customer to the distribution system, to meter usage, and to maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not a customer uses any electricity. This classification includes capital costs associated with poles, wires, services, and meters and operating expenses incurred for customer service, field service, billing, and accounting and related activities.

Energy-related costs are those that vary with the quantity of electricity sold to, or transported for, customers. These costs include purchased power costs and related costs.

Demand-related or capacity-related costs are those expenditures associated with plant that is designed, installed, and operated to meet peak usage. Distribution assets are designed to meet the peak loads of the customers they serve at a localized level. Such localized loads exhibit far less diversity than the aggregation of such localized loads that occurs at the bulk transmission and generation levels. Accordingly, the costs of demand-related distribution assets are allocated among the rate classes based upon their respective class NCP demands (i.e., the peak electricity demand of each rate class, which is not necessarily coincident with each other class or with the system peak).

20. Q. Do all expenses fit neatly into one of these three classifications?

A. Many costs do fit neatly into one of the three classifications, but some costs must be assigned between two classifications based upon special studies or based upon how related costs have been classified. Special studies, such as a minimum size study, are sometimes used to classify poles, conductors, and transformers between customer-related and demand-related investment. A special study was not performed in this case because investment related to such plant operating at secondary voltage was considered to be customer-related and investment in plant operating at primary voltage was considered to be demand-related and, therefore, such plant was classified as customer and demand, respectively.

21. Q. Please describe the class allocation step of a COSS.

A. In the class allocation step, costs that have been functionalized and classified are allocated among the rate classes based on appropriate causal relationships. The allocation phase takes into account the design of the utility system and how it is

operated, cost data derived from the utility's accounting records, and usage and load data both for the system overall and for specific customer classes. Based on analyses of the relationship between costs and the factors driving the need to incur such costs, each component of the revenue requirement is either directly assigned to a rate class or an allocator is selected to apportion that component among rate classes.

22. Q. Please explain the term "direct assignment."

A. The term "direct assignment" means identifying specific plant investments or specific expenses incurred exclusively to serve a specific customer or group of customers. Direct assignments reflect a direct causal connection between costs to serve and the customers being served. Therefore, if data are available to make a direct assignment, it is generally the preferred approach.

23. Q. Can significant portions of a utility's assets and expenses generally be directly assigned in a COSS?

A. No, most costs must be allocated. Utility service is generally provided to customers by facilities that are used, and expenses that are incurred, in common by all, or many, classes of customers. In addition, even in instances where it might be possible to associate specific physical facilities with particular customers, the detailed cost information needed to make a direct assignment may not be reasonably available.

24. Q. Please explain how allocation factors are determined.

A. External and internal allocation factors are typically used to perform a COSS and, consequently, were employed in the Model. External allocators distribute costs in

proportion to customers' use of plant and services represented by functionalized and classified costs. Examples of external allocators are kWh deliveries (for energy-related costs), number of customers (for customer-related costs), and class NCP demands (distribution demand-related costs). PECO Exhibit JD-7 shows the development of the main external allocators. Internal allocators are based on some combination of external allocators, directly assigned costs, and other internal allocators. For example, property insurance costs are allocated in proportion to the plant investment allocated or assigned to each rate class, while plant investment itself is allocated on the basis of one or more external allocation factors (e.g., NCP demand for demand-related plant costs or customer counts for customer-related plant costs).

25. Q. What is the source of the total rate base amount being allocated or assigned to customer classes in the PECO COSS?

A. The total rate base amount employed in the PECO COSS is $10.952 billion (PECO Exhibit JD-1, page 2, line 89) and is derived from PECO Exhibit MJT-1, page 1.

26. Q. What are the major components of PECO's rate base?

A. For purposes of discussing how I functionalized, classified, and allocated rate base in the PECO COSS, I will refer to the following components of rate base:

- Intangible plant
- Distribution plant
- General plant
- Depreciation reserve
- Other rate base items

27. Q. How did you functionalize, classify, and allocate each component of the rate base among the rate classes?

A. The principal allocators for each component of the rate base are discussed below:

Intangible plant represents the costs of franchises and consents and other intangible assets. It was functionalized, classified, and allocated in proportion to distribution plant (i.e., excluding plant serving the Energy and Transmission functions) with the exception of a portion of the total that is associated with Advanced Meter Infrastructure ("AMI"). Intangible AMI system costs, which consist of the software necessary to operate the AMI system and to interface with other systems such as billing, were classified as customer-related and allocated based on the cost of meters.

Distribution plant allocators were developed for specific subcategories of distribution plant, as follows:

- Land and land rights, stations, and structures and improvements were functionalized to Primary HT, classified as demand, and allocated among the rate classes based on their respective class NCP demands at the Primary HT level.
- Poles, towers and fixtures, overhead conductors and devices, underground conduit, and underground conductors and devices were functionalized between Primary HT/Primary, on one hand, and Secondary Distribution, on the other, based on a detailed study of the respective costs, as shown in PECO Exhibit JD-7 at page 4. The Primary HT/Primary portion was split between Primary HT and Primary

based on a study of the respective wire miles of conductors in each function (*see* PECO Exhibit JD-7, p. 5). Costs identified as Primary HT and Primary were classified as demand-related and allocated among the rate classes based on their respective NCP demands at the Primary HT and Primary voltage levels, respectively (*see* PECO Exhibit JD-7, p. 15). Costs identified as Secondary Distribution were classified as customer-related and allocated based on the number of customer locations served.

- Line transformers were functionalized to Secondary Distribution and allocated among the rate classes based on NCP demands at secondary voltage (*see* PECO Exhibit JD-7, p. 15).
- Services connect individual customers to the system and, therefore, were functionalized to their own category, classified as customer-related, and allocated based on the estimated total replacement cost of all services in each rate class (*see* PECO Exhibit JD-7, p. 6). The total replacement cost of services for a rate class was estimated by multiplying the estimated replacement cost of a single service for a member of the class by the number of customer locations in the class.
- Meters were functionalized to their own category, classified as customer-related, and directly assigned based on the cost of new AMI meters installed pursuant to PECO's Smart Meter Universal Deployment Plan, which was approved by the Pennsylvania Public Utility Commission ("Commission") on August 15, 2013 at Docket No. M-2009-2123944 (*see* PECO Exhibit JD-7, p. 7).

- Street lighting and signal systems were functionalized to Customer Other, classified as customer-related, and directly assigned to Lighting.

General plant includes primarily structures and improvements relating to administrative activities, tools, and communications equipment, as well as other miscellaneous assets. These assets were functionalized, classified, and allocated among rate classes based on the direct labor component of operating expenses, which reflects the nature of the assets and common cost-of-service practices for this type of property.

Depreciation reserve was provided by PECO by each asset account. Each component of the depreciation reserve was functionalized, classified, and allocated among rate classes in the same ratio as the related assets.

Other rate base items include primarily materials and supplies, accumulated deferred income taxes, customer deposits, common plant, customer advances for construction, and working capital, as discussed below:

- Materials and supplies were functionalized, classified, and allocated among rate classes in proportion to plant in service.
- Accumulated deferred income taxes were primarily functionalized, classified, and allocated among rate classes in proportion to plant in service.
- Customer deposits were directly assigned to rate classes based on information provided by Mr. Trzaska (included in PECO Exhibit JD-7, p. 8).

- Common plant consists of assets similar to those customarily found in General Plant and, therefore, was functionalized, classified, and allocated among rate classes based on the direct labor component of operating expenses.
- Customer advances were functionalized to Distribution and Secondary Distribution, classified as demand and customer-related, and allocated among the rate classes in the same proportion as Distribution and Secondary Distribution assets.
- Unamortized payment for Residential Battery Energy Storage System Leasing Pilot Program, as described more fully in the direct testimony of PECO witness Steven J. DeMott (Statement No. 11), were functionalized to Distribution and Secondary Distribution, classified as demand and customer-related, and allocated to Residential customers.
- Working capital represents PECO's need for cash to keep the business running until revenues are collected to pay the costs of providing service. Working capital was calculated based on the results of the lead-lag study prepared by Mr. Trzaska and described in (Statement No. 4. Also, working capital was directly assigned to Energy and Transmission based on the results of that lead-lag study. The balance of working capital was functionalized, classified, and allocated to each rate class using methodologies consistent with the nature of the underlying cost.

28. Q. What are the major categories of PECO's expenses?

A. The major expense categories in PECO's cost of service are:

- Distribution operating and maintenance expenses;
- Customer accounts and customer service expenses;
- Administrative and general expenses;
- Depreciation expense;
- Taxes other than income taxes; and
- Income taxes.

29. Q. In determining how to treat these expenses in the COSS, was there another important grouping of expenses that had to be considered?

A. Yes, there was. Labor costs affect each of the first three categories identified above. Consequently, certain cost categories are allocated based on direct labor costs. For example, Account 920 – Administrative and General Salaries is allocated among rate classes based on the composite allocation of direct labor costs included in all operating expense accounts. Likewise, employee benefits are allocated using a labor allocator. In order to develop such allocators, the direct labor costs included in each expense account were obtained from data assembled by Mr. Trzaska.

30. Q. What do PECO's distribution operating and maintenance expenses include and how were these expenses functionalized, classified, and allocated among rate classes?

A. PECO's distribution system consists principally of substations; poles, towers and fixtures; overhead and underground conductors and related equipment; meters; line transformers; outdoor lighting plant; and other miscellaneous assets. Operating and maintenance expenses were analyzed to determine the assets they were incurred to operate or maintain and, therefore, were functionalized, classified, and allocated

among rate classes in the same manner as the assets to which they relate. The COSS also includes costs of purchased power and transmission costs paid to PJM that are recovered through the GSA, TSC, and NBT charges. Purchased power costs were functionalized as Energy, classified as energy-related, and allocated based on projected default service prices and MWh of generation energy revenue in the budget. Transmission-related costs were functionalized as Transmission and assigned among rate classes based on their contributions to the single coincident peak. In addition to the expenses of operating and maintaining PECO's distribution system, distribution expenses include the following:

- **Customer-installation expenses**: These expenses relate to field investigations, high-bill complaints, and potential and actual energy theft, and were allocated based on number of customers.
- **Miscellaneous distribution expenses and rents**: These expenses relate to information technology ("IT") and other expenses associated with all distribution assets. Accordingly, they were functionalized, classified, and allocated among rate classes in proportion to total distribution plant.

31. Q. What do PECO's customer accounts and customer service expenses include and how were those expenses functionalized, classified, and allocated among the rate classes?

A. Customer accounts and customer service expenses primarily include meter-reading expenses, customer records and collection expenses, uncollectible accounts expense, miscellaneous customer accounts expense, customer-assistance expense,

and sales expense. These costs were functionalized to Customer Accounts, classified as customer-related, and allocated as follows:

- **Meter reading expenses** have been supplanted by the new AMI system expenses except for some minor expenses. Costs are allocated based on the cost of meters.
- **Customer records and collection expenses** relate to billing, call center operations, payment processing, arrearage recoveries, support for administration of PECO's CAP program, and termination and restoration of service. The account was analyzed in detail, discrete functions were identified, and expenses related to each function were allocated among rate classes using an appropriate allocation factor (*see* PECO Exhibit JD-7, p. 9). For example, expenses incurred for billing activities were allocated based on number of bills, and call center costs were allocated based on number of customers. A single customer allocation could not be used because some costs are specific to residential customers while others are specific to commercial and industrial customers; therefore, a weighted allocator, based upon the analysis discussed above, was used for this account.
- **Uncollectible accounts expense**, or bad debt expense, was allocated among rate classes based on the Company's experience over a historic three-year period (2023-2025) (*see* PECO Exhibit JD-7, p. 12).

- **Miscellaneous customer accounts expense** includes IT support for the other customer account functions and was allocated among rate classes based on number of customers.
- **Customer assistance expense** includes expenses incurred for the Low-Income Usage Reduction Program and marketing. Costs specific to the residential class were allocated to rates R and RH based on number of customers. Costs specific to the C&I classes were allocated to rates GS, PD and HT based on number of customers on the applicable rates. General marketing costs were allocated based on number of customers (*see* PECO Exhibit JD-7, p. 10).
- **Informational advertising expense** includes the cost of activities that primarily convey information as to what the utility suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy, and was allocated to customer classes based on number of customers.
- **Sales expenses** include expenses incurred in activities, which promote or retain the use of utility distribution services by present and prospective customers, and were allocated to rates GS, PD, and HT customers based on customer energy consumption.

32. Q. How were administrative and general expenses functionalized, classified, and allocated among rate classes?

A. Administrative and general expenses include administrative and general salaries, office supplies and expenses, outside services, property insurance costs, injuries and damages, employee benefits, regulatory commission expenses, miscellaneous general expenses, and maintenance of general plant.

Except for items discussed below, administrative and general expenses are related to labor costs and, therefore, were functionalized, classified, and allocated among rate classes in the same ratio as direct labor expenses.

- **Property insurance costs** were functionalized, classified, and allocated among rate classes in the same ratio as distribution and general plant in service.
- **Regulatory commission expenses** and miscellaneous general expenses were functionalized, classified, and allocated among rate classes in proportion to revenue.
- **Maintenance of general plant expenses** were functionalized, classified, and allocated among rate classes in the same ratio as general plant in service.

33. Q. How were depreciation expense and depreciation reserve functionalized, classified, and allocated among the rate classes?

A. Depreciation expense was derived from PECO Exhibit MH-3, which is sponsored by PECO witness Mariana Hufford, as well as PECO Exhibit MJT-1, which show depreciation expense by plant account. The depreciation reserve was obtained from

the same sources. Both the depreciation expense and the depreciation reserve were functionalized, classified, and allocated among rate classes in the same ratio as the plant account to which they relate.

34. Q. How were taxes other than gross receipts tax and income taxes functionalized, classified, and allocated among the rate classes?

A. Taxes, other than gross receipts tax and income taxes, include Public Utility Realty Tax ("PURTA"), payroll-related taxes, local use taxes, and real estate taxes. Payroll-related taxes were functionalized, classified, and allocated among rate classes in proportion to direct labor expenses. PURTA taxes were allocated based on the allocation of land, local use taxes were allocated based on revenue, and real estate taxes were allocated based on total plant.

35. Q. How was gross receipts tax functionalized, classified, and allocated among the rate classes?

A. Gross receipts tax is based on transmission and distribution revenue, purchased power revenue, and forfeited discounts (i.e., late payment charges). Accordingly, gross receipts tax was calculated separately by function and was classified and allocated among rate classes based on taxable revenue.

36. Q. How was income tax expense functionalized, classified, and allocated among rate classes?

A. Income tax expense was calculated based on revenue at present rates using the same methodology employed by Mr. Trzaska in PECO Exhibit MJT-1, Schedule D-18. Income tax expense was primarily functionalized, classified, and allocated among rate classes based on total plant.

37. Q. How was revenue at present rates computed for each rate class?

A. Distribution revenue at present rates is shown in the proof of revenues set forth in PECO Exhibit JAB-3. The total was assigned to the rate classes based on the proof of revenues. Distribution revenue at present rates for each rate class is shown on page 1, line 4 of PECO Exhibit JD-1.

Supply charge revenue, which consists of revenue collected under the GSA tariffs for energy, administrative costs, and cash working capital, was assigned to rate classes based on projected default service prices and MWh of generation. For each rate class, and in total, supply charge revenue equals the sum of the supply cost (including administrative costs), gross receipts tax, and the revenue requirement for cash working capital.

Transmission charge revenue under the TSC was functionalized to Transmission and allocated among the rate classes in proportion to costs that are allocated based on contributions to the single coincident peak. Revenue equals the sum of the cost plus the revenue requirement for associated cash working capital.

Forfeited discount revenue was functionalized, classified, and allocated in the same ratio as the uncollectible accounts expense.

Rent for electric property represents rental revenue for poles and other property and was functionalized, classified, and allocated in the same ratio as total plant.

Decommissioning payments in the FPFTY represent PECO's transfer to Constellation Energy Company (as successor to Exelon Generation Company) of amounts that PECO collects from customers for nuclear decommissioning expense. Both PECO's recovery of these costs and the transfer of such funds were approved

in the Commission's Order approving the Settlement of PECO's restructuring proceeding.[4] This amount was allocated among the rate classes in the same ratio as the revenue was collected, which is in proportion to each class' billed kWh.

Other electric revenue was allocated among the rate classes based on distribution plant, except for connection charges, returned check fees, solar applications fees and revenue protection which were allocated based on number of customers.

IV. DEVELOPMENT OF RATE CLASS REVENUE REQUIREMENT

38. Q. How did you develop the revenue requirements for each class?

A. The revenue requirements for each rate class were calculated using the same method employed by PECO witness Mr. Trzaska to compute the overall revenue requirement for the FPFTY. Thus, the revenue requirements for each rate class are the sum of that class's allocated operating expenses, depreciation expense, general taxes, return on rate base, and income tax expense. Return on rate base for each rate class was computed by multiplying the rate class's rate base by the proposed system average rate of return. Income taxes included in the revenue requirement for each rate class were computed directly by grossing up the required non-debt return on rate

[4] *Application of PECO Energy Co. for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code and Joint Petition for Partial Settlement; Petition of Enron Energy Services Power, Inc. for Approval of an Electric Competition and Choice Plan and for Authority Pursuant to Section 2807(E)(C) of the Public Utility Code to Serve as the Provider of Last Resort in the Service Territory of PECO Energy Co.*, Docket Nos. R-00973953 and P-00971265, 1997 Pa. PUC LEXIS 51 at *120 (Dec. 23, 1997). On June 9, 2009, the Commission initiated an investigation at Docket No. I-2009-2101331 to determine whether it would be appropriate for PECO to continue the collection of nuclear decommissioning costs from retail customers after the expiration of PECO's rate caps on December 31, 2010 and reaffirmed its earlier holding in PECO's restructuring proceeding. *Investigation into PECO Energy Company's Electric Service Tariff PA P.U.C. No. 4*, 2010 Pa. PUC LEXIS 299 (Order entered July 22, 2010).

base for the class at the applicable statutory income tax rates. PECO Exhibit JD-1, page 2, line 55, shows the total revenue requirements by rate class reflecting the fully allocated distribution cost of service at the proposed system average rate of return. PECO Exhibit JD-1, page 2, line 60, shows the portion of the total revenue requirements PECO proposes to collect in distribution rates.

39. Q. How did you determine the increase or decrease in revenue needed for each class to produce the system average rate of return?

A. The increase or decrease needed for each rate class was calculated by comparing the revenue requirements for each rate class to the forecasted revenue at present rates for that class for the FPFTY. This is the same method used by Mr. Trzaska in PECO Exhibit MJT-1, Schedule A-1, with respect to the overall revenue requirement and revenue deficiency. The increases in rate class revenue needed to produce a rate of return equal to the Company's proposed overall rate of return are shown in PECO Exhibit JD-1 at page 3, line 105, which total $429.1 million. The increases in class distribution revenue are shown on page 2, line 61, which total $423.3 million. The increase in transmission revenue under the TSC are shown on page 2, line 84, which total $0.2 million on a net basis, and the increase in purchased power revenue under the GSA of $5.6 million is shown on page 2, line 73. In addition, forfeited discounts are expected to increase by $1.5 million as a result of the increase in distribution rates.

V. RESULTS OF THE PECO COST-OF-SERVICE STUDY

40. Q. Please describe what is shown on PECO Exhibit JD-1.

A. PECO Exhibit JD-1, which sets forth the substance of the COSS, compares the revenue at current rates by rate class to the revenue requirement allocated on a cost-

of-service basis to each rate class. This information is contained on the first three pages of the exhibit. Net income at present rates, shown in PECO Exhibit JD-1 on line 15, is computed by subtracting operating expenses, depreciation and amortization, taxes other than income taxes, and income taxes (lines 9 to 13, respectively) from revenue at present rates (line 7). The return on rate base at present rates for each rate class is shown in PECO Exhibit JD-1 on line 22, and the relative rates of return are shown on line 23.

Page 3, line 104 shows each rate class's revenue requirement (including revenue from distribution charges, transmission charges, purchased power, forfeited discounts, and other revenue) at the proposed overall rate of return. At page 2, line 93 shows operating expenses, line 94 shows depreciation and amortization expense, line 95 shows taxes other than income taxes excluding the gross receipts tax, line 96 shows gross receipts tax, and line 97 shows income tax expense. Page 2, line 99 shows operating income assuming each rate class pays its full cost of service. Page 3, line 105 shows the increase (decrease) in revenue needed for each rate class to produce revenues equal to its revenue requirement at full cost of service and produce the system average rate of return (excluding forfeited discounts on the increased revenue). Page 2, line 61 shows the increase (decrease) in distribution revenue for each rate class to produce revenue from distribution charges equal to its distribution revenue requirement at full cost of service. Page 2, line 73 shows the increase (decrease) in purchased power revenue for each rate class to produce revenue from purchased power charges equal to its purchased power revenue requirement at full cost of service. Page 2, line 84

shows the increase (decrease) in transmission revenue for each rate class to produce revenue from transmission charges equal to its transmission revenue requirement at full cost of service.

Also included in this exhibit is the rate class cost of service and that shows the allocation of each element of measures of value also known as rate base (RB schedules), operating expenses (E schedules), depreciation expense (D schedules), and taxes (TO and TI schedules) among the rate classes.

41. Q. Please describe what is shown on PECO Exhibit JD-2.

A. PECO Exhibit JD-2 includes the external and internal allocators used for the rate class allocations.

42. Q. Please describe the information contained in PECO Exhibit JD-3.

A. PECO Exhibit JD-3 contains the COSS by functional category and classification. The summary appears on pages 1 to 4 and the account-by-account allocation to functional category and classification is provided on pages 5 to 28.

43. Q. Please describe what is shown in PECO Exhibit JD-4.

A. PECO Exhibit JD-4 presents unitized revenue requirement for each rate class. The unitized revenue requirements are the functionalized and classified revenue requirements allocated to each class of service divided by the appropriate units. For example, demand-related cost is divided by kW of demand, energy-related cost is divided by kWh, and customer-related cost is divided by number of customers. The unit cost is provided by classification and functional area.

44. Q. Which costs were considered in developing the proposed customer charges?

A. The proposed customer charges are based on the specific customer-classified costs in the PECO COSS that are approved for recovery in customer charges. Customer related costs include all costs incurred to attach a customer to the distribution system, to meter usage, and to maintain the customer's account. They include: (1) capital costs associated with portions of the distribution system, services and meters, and general plant supporting the functions identified above; and (2) operating and maintenance expenses related to those assets described in (1), associated administrative and general expense, metering and billing expense, and customer service and account expenses. Total customer costs by rate class for the FPFTY are shown on PECO Exhibit JD-4, in the unit cost analysis.

In Pennsylvania, the costs typically considered in developing residential customer charges exclude allocated portions of the distribution system. Therefore, PECO Exhibit JD-5, Customer-Related Revenue Requirement and Customer Charge, excludes the component shown on PECO Exhibit JD-4 associated with the distribution system. The residential customer charge includes the costs of the service and meter, meter reading-related expense, billing expense, and customer accounting expense together with appropriate pensions and benefits and payroll taxes that are part of the applicable labor expenses. Also included are other supporting administrative and general costs and associated general and common plant and working capital.

45. Q. Please briefly describe the Night Service Rider ("NSR").

A. The NSR applies to distribution service provided to eligible commercial and industrial customers for demand registered in off-peak hours that exceeds their demand during on-peak hours (i.e., 8:00 a.m. to 8:00 p.m. daily (Friday it is 4:00 p.m.), except Saturdays and Sundays). For example, if a customer has an off-peak maximum demand of 200 kW and an on-peak maximum demand of 190 kW, the 10-kW excess of the maximum off-peak demand over the on-peak demand would be billed at the NSR rate, not the standard tariff rate.

46. Q. What costs were included in developing the NSR rate?

A. In developing the NSR rate, I included the cost of overhead and underground conductors, transformers, and the maintenance expenses associated with those conductors and transformers as well as an allocable portion of administrative and general expenses and the cost of common and general plant. These costs are properly included in the NSR rate because off-peak usage affects the size of conductors and transformers.

Those facilities serve load at the localized level and, therefore, do not benefit from load diversity as does other plant, such as substations.

I excluded from the NSR rate the cost of substations, poles, and underground conduit because of the location of substations on the system. The size of substations is affected by on-peak demand. The cost of poles and conduit were also excluded because off-peak demand in excess of on-peak demand is unlikely to affect the size of those facilities (PECO Exhibit JD-6).

Mr. Bisti uses these costs to determine the appropriate charge for the NSR as discussed in his direct testimony (Statement No. 9).

47. Q. Please describe the information shown on PECO Exhibit JD-7.

A. PECO Exhibit JD-7 shows the development of the external allocators, which are described below and are used in the COSS. Except where noted, all data are for the FPFTY.

Index (page 1) - Table of External Allocators

Summary of External Allocator Values (page 2) - Class Allocation

Summary of External Allocator Values (page 3) - Functionalization

Conductors-Functional Splits (page 4) - Allocates the cost of Overhead Conductors and Underground Conductors between Primary HT/Primary and Secondary based on a study that the Company previously prepared to separate costs by voltage levels. The functional split for poles follows the overhead conductor split, and the functional split for underground conduit follows underground conductor split.

Conductors-Primary Splits (page 5) - Allocates the cost of Overhead Conductors operating at primary voltage between Primary HT and Primary based on the wire miles of those conductors as of December 31, 2025. The same approach was used for Underground Conductors. The functional split for poles follows the overhead conductor split, and the functional split for underground conduit follows underground conductor split.

Service Costs (page 6) - Computes investment in services for each rate class at average replacement cost for the period 2024-2025. PECO does not account for

services separately and, therefore, has used estimated replacement cost to allocate the account to the classes of service.

Meter Costs (page 7) - Meter costs were allocated among rate classes based on the average cost of meters of each type for each rate class, as determined from the Company's records as of November 2025. Meter costs include both materials and labor.

Customer Deposits (page 8) - Allocates FPFTY customer deposits based on the 13-month average customer deposit balances for each class for the period from December 2024 through December 2025.

Account 903 Allocator (page 9) - Allocates costs associated with each activity recorded in Account 903 – Customer Records and Collection Expense for 2024 using an appropriate external allocator. Each activity, the cost of the activity, and the allocator assigned to each is shown in a separate row. Row 11 summarizes the costs by rate class. The weighted allocators are shown on row 12. The separate allocations are necessary because some costs are only applicable to specific rate classes.

Account 908 Allocator (page 10) - Allocates the costs of each activity recorded in Account 908 – Customer Assistance for 2024 using an appropriate external allocator. Rows 1-5 list each activity, the cost of the activity and the allocator assigned to it. Row 6 summarizes the costs by rate class. The allocators are on row 7.

Account 912 Allocator (page 11) - Allocates the cost recorded in Accounts 912 – Demonstrating and Selling Expense for 2024 using an appropriate external allocator.

Write-Offs (page 12) - Computes the Write-Off allocators using net charge-offs for 2023 through 2025.

Over 60-Day (page 13) - Computes the Over 60-Day allocators. The column "Over 60-Day Allocator" shows the percentage of PECO's total electric accounts receivable outstanding for more than two months for each rate class at each month-end from January 2025 through December 2025.

Purchase of Receivables (page 14) - Computes the allocator used in the COSS to allocate the POR portion of cash working capital.

Demand Allocators (page 15) - Computes the demand allocators used in the COSS based on data from October 2024 through September 2025.

MWh Deliveries at Generation (page 16) - Computes MWh at the different rate classes based on projected 2027 sales at the meter and appropriate loss factors for each rate class. The class loss factors are the same as those set forth in the Company's Electric Generation Supplier Coordination Tariff.

Customer and Location-Based Allocators (page 2) - The demand-based, customer-based and location-based allocators are shown on page 2 at lines 4-15. The location-based allocator (Location Secondary) shown on line 15 was modified for street lighting to reflect 25% of each of the total locations for the Lighting class. This adjustment was made to more accurately reflect cost causation. Street lights are generally located where there are existing Company facilities serving other load.

In some cases, street lights were installed after the grid was in place and, therefore, did not contribute to the need for poles, conductors, or conduit to be installed. However, that is not always the case and, in some instances, the system was built out for the lights, for example, as on some bridges and roads. Counting each location as a separate customer would allocate too much cost to street lighting. On the other hand, not counting any lighting locations as customers would understate the costs allocated to street lighting. Even where the system was in place before street lights were installed, it is appropriate to allocate some cost to the Lighting class because the service is benefiting from the poles, conductors, and conduit. I have, therefore, applied a 25% factor to the number of locations to allocate a reasonable level of cost to the Lighting class.

48. Q. Please explain how the purchased power and transmission sections of the COSS are used?

A. In the cost-of-service summary there is a section for purchased power and a section for transmission. These sections are used to derive the unbundled cash working capital requirement that is recovered in the GSA and the TSC. The revenue requirement associated with cash working capital is used to develop a rate for the GSA and TSC. The total revenue requirement used to develop the rate is the operating income consisting of return, income taxes, and the associated gross receipts tax. I am providing PECO Exhibit JD-8 to show the calculation of the unbundled cash working capital rate for the GSA. PECO Exhibit JD-9 provides the calculation of the unbundled cash working capital rate for the TSC. The rate developed in PECO Exhibit JD-8 of $0.00069 per kWh will replace the rate of

\$0.00035 per kWh currently in the GSA. The rate developed in PECO Exhibit JD-9 of \$311 per MW-year will replace the current rate of \$274 per MW-year in the TSC.

VI. CONCLUSION

49. Q. Please summarize your conclusion with respect to the COSS.

A. The Company's COSS was prepared using an appropriate and well-accepted cost of service method. The results of the Company's COSS provide a reasonable allocation of PECO's cost of service among its rate classes and are an appropriate guide for use in designing PECO's proposed rates.

50. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Jiang Ding, hereby state that I am a Principal Regulatory and Rates Specialist for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 8 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Jiang Ding

Dated: March 30, 2026

Jiang Ding

PECO Exhibit JD-1:
Summary of Results and Revenue Requirement by Rate Class

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
S	1	**SUMMARY OF RETURN AT PRESENT RATES**											
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**											
S	3	OPERATING REVENUE											
S	4	Sales of Electricity - Base				1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
S	5	Decommissioning Revenues				(4,213)	(1,313)	(325)	(874)	(33)	(1,599)	(54)	(16)
S	6	Other Operating Revenue				58,150	35,457	8,194	8,945	167	4,560	256	572
S	7	TOTAL OPERATING REVENUE				2,034,528	1,168,680	227,226	352,309	9,992	237,054	9,864	29,401
S													
S	8	OPERATING EXPENSES											
S	9	Operation and Maintenance Expense				860,811	523,104	113,818	124,379	3,623	81,315	4,352	10,220
S	10	Depreciation and Amortization Expense				424,593	230,177	55,258	76,821	1,990	52,172	2,882	5,292
S	11	Taxes Other Than Income Taxes-General				30,519	16,631	3,991	4,996	151	4,210	234	306
S	12	Taxes Other Than Income Taxes-Distribution GRT				114,483	65,217	12,560	20,055	581	13,798	570	1,702
S	13	Income Taxes				16,736	12,980	(8,121)	6,794	291	4,293	(568)	1,067
S	14	TOTAL OPERATING EXPENSES				1,447,142	848,109	177,507	233,046	6,636	155,789	7,470	18,586
S	15	OPERATING INCOME (RETURN)				587,385	320,571	49,719	119,264	3,356	81,266	2,394	10,816
S													
S	16	DEVELOPMENT OF RATE BASE											
S	17	Electric Plant in Service				13,154,586	6,875,998	1,748,971	2,474,212	61,666	1,693,067	97,558	203,115
S	18	Less: Accumulated Depreciation				2,223,678	1,135,062	275,248	438,417	10,020	295,772	16,504	52,656
S	19	Plus: Rate Base Additions				1,072,510	610,029	130,488	179,182	5,188	131,095	5,241	11,286
S	20	Less: Rate Base Deductions				1,155,663	599,183	149,435	233,667	5,325	143,838	7,871	16,344
S	21	TOTAL DISTRIBUTION RATE BASE				10,847,754	5,751,782	1,454,776	1,981,310	51,508	1,384,552	78,424	145,401
S													
S	22	DISTRIBUTION RATE OF RETURN (PRESENT)				5.41%	5.57%	3.42%	6.02%	6.52%	5.87%	3.05%	7.44%
S	23	DISTRIBUTION INDEX RATE OF RETURN (PRESENT)				1.00	1.03	0.63	1.11	1.20	1.08	0.56	1.37
S													
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**											
S	25	Purchased Electric Revenues				1,612,994	1,040,649	259,956	228,750	1,695	81,286	0	658
S	26	Purchased Power O&M Expense				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
S	27	Purchased Power GRT Expense				95,167	61,398	15,337	13,496	100	4,796	0	39
S	28	Purchased Power Income Taxes				531	342	86	75	1	27	0	0
S	29	Purchased Power Operating Income				3,505	2,261	565	497	4	177	0	1
S	30	Rate Base - Purchased Pwr Cash Working Capital				91,220	58,852	14,701	12,937	96	4,597	0	37
S	31	PURCHASED POWER RATE OF RETURN (PRESENT)				3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	0.00%	3.84%
S													
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**											
S	33	Transmission Revenues				241,020	132,058	32,991	47,223	658	26,979	1,074	37
S	34	Transmission O&M Expense				225,704	123,666	30,895	44,222	616	25,264	1,006	34
S	35	Transmission GRT Expense				14,220	7,791	1,946	2,786	39	1,592	63	2
S	36	Transmission Income Taxes				215	123	35	43	0	14	1	(0)
S	37	Transmission Operating Income				880	477	115	172	3	108	4	0
S	38	Rate Base - Transmission Cash Working Capital				12,703	6,076	886	2,436	84	3,099	114	9
S	39	TRANSMISSION RATE OF RETURN (PRESENT)				6.93%	7.85%	13.02%	7.07%	3.20%	3.50%	3.73%	2.01%
S													
S	40	TOTAL OPERATING INCOME (RETURN)				591,770	323,309	50,400	119,933	3,362	81,551	2,399	10,817
S	41	TOTAL RATE BASE				10,951,677	5,816,710	1,470,364	1,996,682	51,688	1,392,247	78,538	145,447
S	42	COMPOSITE RATE OF RETURN AT CURRENT RATES				5.40%	5.56%	3.43%	6.01%	6.51%	5.86%	3.05%	7.44%
S													
S													
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**											
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**											
S	45	RATE BASE				10,847,754	5,751,782	1,454,776	1,981,310	51,508	1,384,552	78,424	145,401
S	46	RETURN (= RATE BASE * 8.08% ROR)				876,500	464,745	117,546	160,090	4,162	111,872	6,337	11,748
S	47	PLUS:											
S	48	OPERATING EXPENSES											
S	49	Operation and Maintenance Expense				867,155	526,279	115,298	125,275	3,641	81,985	4,437	10,240

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator			Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
S	50	Depreciation and Amortization Expense				424,593	230,177	55,258	76,821	1,990	52,172	2,882	5,292
S	51	Taxes Other Than Income Taxes-General				30,519	16,631	3,991	4,996	151	4,210	234	306
S	52	Taxes Other Than Income Taxes-Distribution GRT				139,458	77,672	18,419	23,582	651	16,441	911	1,782
S	53	State and Federal Income Taxes				121,092	65,019	16,361	21,531	582	15,341	855	1,403
S	54	TOTAL OPERATING EXPENSES				1,582,817	915,778	209,328	252,205	7,014	170,149	9,319	19,023
S													
S	55	EQUALS TOTAL COST OF SERVICE				2,459,317	1,380,523	326,874	412,295	11,176	282,021	15,656	30,772
S	56	LESS:											
S	57	Decommissioning Revenues				(4,213)	(1,313)	(325)	(874)	(33)	(1,599)	(54)	(16)
S	58	Other Operating Revenue				59,635	36,200	8,541	9,154	171	4,717	276	576
S	59	EQUALS:											
S	60	DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR				2,403,895	1,345,635	318,658	404,014	11,039	278,904	15,433	30,211
S	61	Distribution Cost Increase without Forfeited Discount				423,300	211,097	99,301	59,775	1,180	44,810	5,771	1,366
S	62	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE				424,789	211,843	99,648	59,986	1,184	44,967	5,791	1,370
S	63	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUNT(%)				21.37%	18.61%	45.27%	17.36%	11.97%	19.14%	59.73%	4.73%
S						8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**											
S	65	RATE BASE (CWC)				91,220	58,852	14,701	12,937	96	4,597	0	37
S	66	RETURN (= RATE BASE * 8.08% ROR)				7,371	4,755	1,188	1,045	8	371	0	3
S	67	PLUS:											
S	68	OPERATING EXPENSES											
S	69	Purchased Power O&M Expense				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
S	70	Purchased Power Income Taxes				1,926	1,243	310	273	2	97	0	1
S	71	Purchased Power GRT Expense				95,497	61,611	15,391	13,543	100	4,813	0	39
S	72	EQUALS TOTAL PURCHASED POWER COST OF SERVICE				1,618,585	1,044,256	260,857	229,543	1,701	81,568	0	660
S	73	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE				5,591	3,607	901	793	6	282	0	2
S	74	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)				0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.00%	0.35%
S						8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**											
S	76	RATE BASE (CWC)				12,703	6,076	886	2,436	84	3,099	114	9
S	77	RETURN (= RATE BASE * 8.08% ROR)				1,026	491	72	197	7	250	9	1
S	78	PLUS:											
S	79	OPERATING EXPENSES											
S	80	Transmission O&M Expense				225,704	123,666	30,895	44,222	616	25,264	1,006	34
S	81	Transmission Income Taxes				268	128	19	51	2	65	2	0
S	82	Transmission GRT Expense				14,233	7,793	1,943	2,788	39	1,604	64	2
S	83	EQUALS TOTAL TRANSMISSION COST OF SERVICE				241,232	132,078	32,928	47,259	664	27,184	1,082	38
S	84	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE				212	20	(63)	36	6	205	7	1
S	85	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)				0.09%	0.02%	-0.19%	0.08%	0.90%	0.76%	0.67%	2.06%
S						8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**				430,592	215,470	100,486	60,814	1,196	45,454	5,799	1,373
S													
S													
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**											
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**											
S	89	RATE BASE				10,951,677	5,816,710	1,470,364	1,996,682	51,688	1,392,247	78,538	145,447
S	90	RETURN (= RATE BASE * 8.08% ROR)				884,897	469,991	118,806	161,332	4,176	112,494	6,346	11,752
S	91	PLUS:											
S	92	OPERATING EXPENSES											
S	93	Operation and Maintenance Expense				2,606,652	1,626,592	390,161	384,179	5,847	183,536	5,443	10,892
S	94	Depreciation and Amortization Expense				424,593	230,177	55,258	76,821	1,990	52,172	2,882	5,292
S	95	Taxes Other Than Income Taxes-General				30,519	16,631	3,991	4,996	151	4,210	234	306
S	96	Taxes Other Than Income Taxes-GRT				249,187	147,076	35,752	39,913	790	22,858	974	1,823
S	97	State and Federal Income Taxes				123,286	66,390	16,691	21,855	585	15,503	858	1,404
S	98	TOTAL OPERATING EXPENSES				3,434,237	2,086,866	501,854	527,765	9,364	278,280	10,391	19,717
S													
S	99	EQUALS TOTAL COST OF SERVICE				4,319,134	2,556,857	620,659	689,097	13,541	390,773	16,737	31,470

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)			(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
S	100	LESS:											
S	101	Decommissioning Revenues				(4,213)	(1,313)	(325)	(874)	(33)	(1,599)	(54)	(16)
S	102	Other Operating Revenue				59,635	36,200	8,541	9,154	171	4,717	276	576
S	103	EQUALS:											
S	104	OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR				4,263,712	2,521,970	612,443	680,816	13,403	387,656	16,515	30,909
S	105	COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUNT				429,106	214,726	100,139	60,604	1,192	45,297	5,779	1,369
S	106	TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE				430,592	215,470	100,486	60,814	1,196	45,454	5,799	1,373
S						8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S													
S													
S												

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
RBP	20	364-Poles,Towers & Fixtures											
RBP	21	Primary HT	DDISPHT			909,779	379,285	116,034	169,085	5,847	222,394	12,981	4,152
RBP	22	Primary	DDISTPOL			479,969	269,935	82,581	120,337	4,162	0	0	2,955
RBP	23	Secondary	CDISTSOLC			535,797	406,708	63,423	46,960	0	0	0	18,706
RBP	24	Total Account 364				1,925,544	1,055,927	262,039	336,381	10,009	222,394	12,981	25,814
RBP	25	365-Overhead Conductors & Devices											
RBP	26	Primary HT	DDISPHT			1,290,018	537,805	164,531	239,753	8,291	315,343	18,407	5,888
RBP	27	Primary	DDISTPOL			680,570	382,753	117,096	170,631	5,901	0	0	4,190
RBP	28	Secondary	CDISTSULC			759,731	576,690	89,931	66,586	0	0	0	26,524
RBP	29	Total Account 365				2,730,320	1,497,248	371,557	476,970	14,192	315,343	18,407	36,602
RBP	30	366-Underground Conduit											
RBP	31	Primary HT	DDISPHT			829,340	345,750	105,775	154,135	5,330	202,731	11,834	3,785
RBP	32	Primary	DDISTPUL			203,444	114,417	35,004	51,007	1,764	0	0	1,253
RBP	33	Secondary	CDISTSOLC			329,526	250,133	39,006	28,881	0	0	0	11,505
RBP	34	Total Account 366				1,362,310	710,301	179,785	234,023	7,094	202,731	11,834	16,542
RBP	35	367-Underground Conductors & Devices											
RBP	36	Primary HT	DDISPHT			1,616,189	673,785	206,131	300,373	10,388	395,075	23,061	7,376
RBP	37	Primary	DDISTPUL			396,465	222,972	68,214	99,401	3,438	0	0	2,441
RBP	38	Secondary	CDISTSULC			642,168	487,451	76,014	56,283	0	0	0	22,420

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)			(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
RBP	39	Total Account 367				2,654,822	1,384,209	350,359	456,056	13,825	395,075	23,061	32,237
RBP	40	368-Line Transformers	DDISTSUT			1,145,141	649,661	198,751	289,618	0	0	0	7,112
RBP	41	369-Services	CSERVICE			516,670	281,055	43,828	187,976	450	3,361	0	0
RBP	42	370-Meters	CMETERS			413,020	276,443	44,799	69,960	1,600	19,993	225	0
RBP	43	371-Installation on Customer Premises	CUSTPREM			16,772	12,731	1,985	1,470	0	0	0	586
RBP	44	373-Street Lighting & Signal Systems	CLIGHT			72,331	0	0	0	0	0	0	72,331
RBP	45	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR			4,017	2,105	535	759	19	507	29	64
RBP	46	SUBTOTAL DISTRIBUTION PLANT				12,935,381	6,742,843	1,720,765	2,442,467	60,652	1,671,385	96,422	200,847
RBP													
RBP	47	ENERGY STORAGE PLANT											
RBP	48	387 [Reserved]	SALWAGES			0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	SALWAGES			0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	SALWAGES			0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	SALWAGES			0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	SALWAGES			0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	SALWAGES			0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	SALWAGES			0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	SALWAGES			0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	SALWAGES			0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	SALWAGES			0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	SALWAGES			0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	SALWAGES			0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	SALWAGES			0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT				0	0	0	0	0	0	0	0
RBP													
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)				12,935,381	6,742,843	1,720,765	2,442,467	60,652	1,671,385	96,422	200,847
RBP													
RBP													
RBP													
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**											
RBP													
RBP	64	GENERAL PLANT											
RBP	65	389-Land and Land Rights	SALWAGES			930	563	120	134	4	94	5	10
RBP	66	390-Structures and Improvements	SALWAGES			65,382	39,588	8,456	9,414	304	6,573	348	698
RBP	67	391-Office Furniture & Equipment	SALWAGES			8,231	4,984	1,065	1,185	38	828	44	88
RBP	68	393-Store Equipment	SALWAGES			38	23	5	6	0	4	0	0
RBP	69	394-Tools, Shop & Garage Equip.	SALWAGES			64,233	38,892	8,307	9,249	299	6,458	342	686
RBP	70	395-Laboratory Equipment	SALWAGES			85	51	11	12	0	9	0	1
RBP	71	397 Communication Equipment											
RBP	72	397.1 Computer Hardware	SALWAGES			6,872	4,161	889	989	32	691	37	73
RBP	73	397.2 Computer Software	SALWAGES			23,829	14,428	3,082	3,431	111	2,396	127	254
RBP	74	397.3 Communication Equipment	SALWAGES			38,899	23,553	5,031	5,601	181	3,911	207	415
RBP	75	Total Account 397				69,600	42,142	9,001	10,021	324	6,997	371	743
RBP	76	398-Miscellaneous Equipment / ARO	SALWAGES			1,750	1,060	226	252	8	176	9	19
RBP	77	399-Other Tangible Property	SALWAGES			1,898	1,149	246	273	9	191	10	20
RBP	78	TOTAL GENERAL PLANT				212,149	128,453	27,437	30,546	987	21,329	1,131	2,266
RBP													
RBP													
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**				13,154,586	6,875,998	1,748,971	2,474,212	61,666	1,693,067	97,558	203,115

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
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RBP													
RBD	1	**LESS: ACCUMULATED DEPRECIATION**											
RBD													
RBD	2	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	INTPLT			0	0	0	0	0	0	0	0
RBD													
RBD	3	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	TRANPLT			0	0	0	0	0	0	0	0
RBD													
RBD	4	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION											
RBD	5	360-Land & Land Rights	PLT_360			310	129	40	58	2	76	4	1
RBD	6	361-Structures & Improvements	PLT_361			57,133	23,819	7,287	10,618	367	13,966	815	261
RBD	7	362-Station Equipment	PLT_362			492,797	205,446	62,852	91,588	3,167	120,463	7,032	2,249
RBD	8	363-Computer HW SW and Equipment	PLT_363			179,828	74,970	22,935	33,421	1,156	43,959	2,566	821
RBD	9	364-Poles,Towers & Fixtures	PLT_364			(2,932)	(1,608)	(399)	(512)	(15)	(339)	(20)	(39)
RBD	10	365-Overhead Conductors & Devices	PLT_365			328,256	180,009	44,671	57,344	1,706	37,913	2,213	4,401
RBD	11	366-Underground Conduit	PLT_366			225,322	117,481	29,736	38,707	1,173	33,531	1,957	2,736
RBD	12	367-Underground Conductors & Devices	PLT_367			148,586	77,472	19,609	25,525	774	22,112	1,291	1,804
RBD	13	368-Line Transformers	PLT_368			150,614	85,446	26,141	38,092	0	0	0	935
RBD	14	369-Services	PLT_369			227,180	123,580	19,271	82,653	198	1,478	0	0
RBD	15	370-Meters	PLT_370			274,521	183,743	29,776	46,500	1,064	13,289	150	0
RBD	16	371-Installation on Customer Premises	PLT_371			11,947	9,069	1,414	1,047	0	0	0	417
RBD	17	373-Street Lighting & Signal Systems	PLT_373			38,073	0	0	0	0	0	0	38,073
RBD	18	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR			2,749	1,441	366	519	13	347	20	43
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION				2,134,385	1,080,996	263,699	425,560	9,605	286,794	16,028	51,702
RBD													

PECO Energy Company
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Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)			(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATION	ENSTORPLT			0	0	0	0	0	0	0	0
RBD													
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT			89,294	54,066	11,548	12,857	415	8,977	476	954
RBD													
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**				2,223,678	1,135,062	275,248	438,417	10,020	295,772	16,504	52,656
RBD													
RBD													
RBD													
RBD	23	**NET ELECTRIC PLANT IN SERVICE**				10,930,908	5,740,936	1,473,723	2,035,795	51,646	1,397,295	81,054	150,459
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RBD													
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**											
RBO													
RBO	2	**PLUS: ADDITIONS TO RATE BASE**											
RBO													
RBO	3	COMMON PLANT	SALWAGES			620,339	375,606	80,229	89,320	2,886	62,368	3,306	6,625
RBO	4	Pension Assets / (Liability)	SALWAGES			161,288	97,658	20,859	23,223	750	16,216	860	1,723
RBO													
RBO	5	**WORKING CAPITAL**											
RBO	6	Purchased Power Cash Working Capital				91,220	58,852	14,701	12,937	96	4,597	0	37
RBO	7	Transmission Cash Working Capital				12,703	6,076	886	2,436	84	3,099	114	9
RBO	8	Distribution											
RBO	9	Cash Working Capital				237,794	109,015	22,342	56,655	1,303	45,678	682	2,119
RBO	10	Materials and Supplies	TOTPLT			53,088	27,750	7,058	9,985	249	6,833	394	820
RBO	11	Total Distribution Working Capital				290,882	136,765	29,401	66,640	1,552	52,511	1,076	2,938
RBO	12	TOTAL WORKING CAPITAL				394,805	201,692	44,988	82,012	1,732	60,207	1,190	2,984
RBO	13	TOTAL ADDITIONS TO RATE BASE				1,176,432	674,956	146,076	194,554	5,368	138,790	5,355	11,332

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
RBO													
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**											
RBO	15	Customer Deposits	CUSTDEP			66,853	21,953	4,874	33,280	232	6,514	0	0
RBO	16	Customer Advances for Construction	CUSTADV			10,468	5,609	1,405	1,815	54	1,370	80	134
RBO	17	Deferred Income Taxes and Credits											
RBO	18	Plant	TOTPLT			1,006,714	526,217	133,848	189,350	4,719	129,570	7,466	15,544
RBO	19	Common Plant	SALWAGES			91,299	55,280	11,808	13,146	425	9,179	487	975
RBO	20	Corporate Alternative Minimum Tax	TOTPLT			(12,621)	(6,597)	(1,678)	(2,374)	(59)	(1,624)	(94)	(195)
RBO	21	Unamortized AMR Investment	CMETERS			0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	CUSTADV			(8,940)	(4,791)	(1,200)	(1,550)	(47)	(1,170)	(68)	(115)
RBO	23	Unamortized Payment for BESS	CUSTADVRRH			1,890	1,512	378	0	0	0	0	0
RBO	24	Total Deferred Income Taxes and Credits				1,076,453	570,109	142,778	198,572	5,038	135,954	7,791	16,210
RBO	25	TOTAL DEDUCTIONS TO RATE BASE				1,155,663	599,183	149,435	233,667	5,325	143,838	7,871	16,344
RBO													
RBO													
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE				1,072,510	610,029	130,488	179,182	5,188	131,095	5,241	11,286
RBO													
RBO	27	TOTAL PURCHASED POWER RATE BASE				91,220	58,852	14,701	12,937	96	4,597	0	37
RBO	28	TOTAL TRANSMSSION RATE BASE				12,703	6,076	886	2,436	84	3,099	114	9
RBO	29	TOTAL DISTRIBUTION RATE BASE				10,847,754	5,751,782	1,454,776	1,981,310	51,508	1,384,552	78,424	145,401
RBO													
RBO	30	**TOTAL RATE BASE**				10,951,677	5,816,710	1,470,364	1,996,682	51,688	1,392,247	78,538	145,447
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RBO													
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**											
RBC	2	**DISTRIBUTION**											
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	4	Payroll (Distribution Only)	SALWAGES			187,276	113,393	24,220	26,965	871	18,828	998	2,000
RBC	5	Pension	SALWAGES			2,988	1,809	386	430	14	300	16	32
RBC	6	Other Expenses	OMXPPPP			734,716	435,817	98,660	115,972	2,721	71,286	3,552	6,708
RBC	7	TOTAL EXPENSES				924,980	551,019	123,267	143,367	3,606	90,414	4,566	8,740
RBC	8	POR Working Capital	POR			1,428,686	329,053	81,347	523,862	10,016	480,428	0	3,980
RBC	9	TOTAL EXPENSES PER DAY				6,448	2,411	561	1,828	37	1,564	13	35
RBC													
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)				141,842	53,037	12,331	40,210	821	34,401	275	767
RBC													
RBC	11	AVERAGE PREPAYMENTS				8,432	5,168	1,150	1,259	28	717	34	74
RBC	12	DISTRIBUTION ACCRUED TAXES				110,012	62,567	11,851	19,416	559	13,455	539	1,625
RBC	13	INTEREST PAYMENTS	TOTPLT			(22,491)	(11,756)	(2,990)	(4,230)	(105)	(2,895)	(167)	(347)
RBC													
RBC													
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIREMENT				237,794	109,015	22,342	56,655	1,303	45,678	682	2,119

PECO Energy Company
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Sch.	Line No.	Description	Allocator			Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
RBC													
RBC													
RBC	15	**PURCHASED POWER**											
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	17	Commodity Purchased - Contract Purchases	ENERGY1			1,501,553	968,751	241,996	212,946	1,578	75,670	0	613
RBC	18	Commodity Purchased - Spot Market Purchases	ENERGY1			12,239	7,896	1,972	1,736	13	617	0	5
RBC	19	TOTAL EXPENSES				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
RBC													
RBC	20	TOTAL EXPENSES PER DAY				4,147	2,676	668	588	4	209	0	2
RBC													
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)				91,220	58,852	14,701	12,937	96	4,597	0	37
RBC													
RBC	22	Energy ACCRUED TAXES	ENERGY1			0	0	0	0	0	0	0	0
RBC													
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT				91,220	58,852	14,701	12,937	96	4,597	0	37
RBC													
RBC	24	**TRANSMISSION**											
RBC	25	O&M EXPENSE - PJM Transmission Purchase	DTRAN			102,810	49,172	7,173	19,712	681	25,079	924	70
RBC													
RBC	26	TOTAL EXPENSES PER DAY				282	135	20	54	2	69	3	0
RBC													
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)				12,703	6,076	886	2,436	84	3,099	114	9
RBC													
RBC	28	TRANSMISSION ACCRUED TAXES	DTRAN			0	0	0	0	0	0	0	0
RBC													
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT				12,703	6,076	886	2,436	84	3,099	114	9
RBC													
RBC													
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT				341,717	173,943	37,930	72,027	1,483	53,374	796	2,165
RBC													
RBC													
RBC													
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**											
RBC													
RBC	2	**LAG/LEAD DAYS**					**NET DAYS**						
RBC	3	REVENUE LAG DAYS				57.60							
RBC	4	EXPENSE LAG DAYS				35.00	22.59						
RBC	5	PURCHASED POWER REVENUE LAG DAYS				57.60							
RBC	6	PURCHASED POWER EXP LAG DAYS				35.60	21.99						
RBC	7	TRANSMISSION REVENUE LAG DAYS				57.60							
RBC	8	TRANSMISSION EXP LAG DAYS				12.50	45.10						
RBC	9	DISTRIBUTION REVENUE LAG DAYS				57.60							
RBC	10	DISTRIBUTION LAG DAYS				35.60	22.00						
RBC													
RBC													
RBC													
RBC													
RBC	11	DISTRIBUTION ACCRUED TAXES											

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
RBC	12	Federal Income Tax	EBT			1,463,760	829,585	37,005	330,865	10,095	220,982	313	34,915
RBC	13	State Income Tax	EBT			259,962	147,333	6,572	58,761	1,793	39,246	56	6,201
RBC	14	PURTA Taxes	PLT_3601			813,970	339,342	103,815	151,278	5,232	198,974	11,614	3,715
RBC	15	Capital Stock	CAPSTOCK			0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	PROPREV			0	0	0	0	0	0	0	0
RBC	17	PA Property tax	TOTPLT			544,299	284,509	72,367	102,376	2,552	70,054	4,037	8,404
RBC	18	PA Corp Loan Tax	TOTPLT			0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	SALESREV			0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	SALESREV			0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	SALESREV			37,072,413	21,236,086	4,105,884	6,443,405	184,535	4,381,722	180,853	539,928
RBC	22	Lag Day Weighted Accrued Taxes				40,154,403	22,836,855	4,325,644	7,086,686	204,206	4,910,977	196,873	593,163
RBC	23	TOTAL ACCRUED TAXES CWC				110,012	62,567	11,851	19,416	559	13,455	539	1,625
RBC													
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS											
RBC	25	Customer Experience	CUST			173	135	21	16	0	0	0	1
RBC	26	EEI, EAP and EPRI Dues	PROPREV			521	308	75	83	2	47	2	4
RBC	27	PUC Assess - Electric	PROPREV			3,948	2,335	567	630	12	359	15	29
RBC	28	Prepaid Rents and Pole Attachment Fees	PLT_364			417	229	57	73	2	48	3	6
RBC	29	Land Leasing	DISTPLT			50	26	7	9	0	6	0	1
RBC	30	Equipment Maintenance	DISTPLT			81	42	11	15	0	10	1	1
RBC	31	Business Support System	CUST			464	361	56	42	0	1	0	3
RBC	32	VEBA Adjustment	SALWAGES			1,651	1,000	214	238	8	166	9	18
RBC	33	Facilities Contracts	DISTPLT			36	19	5	7	0	5	0	1
RBC	34	IT Service Contracts	TOTPLT			305	159	41	57	1	39	2	5
RBC	35	Fleet Activities	GENLPLT			337	204	44	49	2	34	2	4
RBC	36	Postage	CUSTBILLS			449	350	55	40	0	1	0	3
RBC	37	TOTAL AVERAGE PREPAYMENTS				8,432	5,168	1,150	1,259	28	717	34	74
RBC													
RBC													
RBC													
RBC													
RBC													
RBC													
RBC													
RBC	38	**OPERATING REVENUES**											
RBC													
RBC	39	**SALES REVENUES**											
RBC	40	Sales of Electricity Revenues - Base				1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	ENERGY2			(4,213)	(1,313)	(325)	(874)	(33)	(1,599)	(54)	(16)
RBC	42	Transmission Revenues	DTRANR			241,020	132,058	32,991	47,223	658	26,979	1,074	37
RBC	43	Purchased Electric Revenues	ENERGY1			1,612,994	1,040,649	259,956	228,750	1,695	81,286	0	658
RBC	44	TOTAL SALES OF ELECTRICITY				3,830,392	2,305,930	511,979	619,338	12,178	340,759	10,683	29,525
RBC													
RBC	45	**OTHER OPERATING REVENUES**											
RBC	46	Unbilled and Cost Adjustment Revenue	SALESREV			0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	OX_904			18,527	13,439	2,984	1,990	4	109	0	1
RBC	48	454-Rent from Electric Property	TOTPLT			27,708	14,483	3,684	5,211	130	3,566	205	428
RBC	49	456-Other Electric Revenues											
RBC	50	Connection Charges/Returned Check Fees/Solar Application Fees/Revenue Protect	CUST			5,129	3,998	623	462	1	8	0	37
RBC	51	All Other	DISTPLT			6,786	3,537	903	1,281	32	877	51	105
RBC	52	Total 456-Other Electric Revenues				11,915	7,535	1,526	1,743	33	885	51	143
RBC	53	TOTAL OTHER OPERATING REV				58,150	35,457	8,194	8,945	167	4,560	256	572
RBC													
RBC	54	**TOTAL OPERATING REVENUES**				3,888,542	2,341,387	520,173	628,283	12,345	345,319	10,939	30,096

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
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E	1	**OPERATION & MAINTENANCE EXPENSE**											
E													
E	2	PRODUCTION EXPENSE											
E	3	Other Power Supply											
E	4	555 - Purchased Power - Capacity	ENERGY1			1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
E	5	Total Other Power Supply				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
E	6	TOTAL PRODUCTION EXPENSE				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
E													
E	7	TRANSMISSION EXPENSES											
E	8	Operation Expense	DTRANR			225,704	123,666	30,895	44,222	616	25,264	1,006	34
E	9	Maintenance Expense	DTRAN			0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE				225,704	123,666	30,895	44,222	616	25,264	1,006	34
E													
E	11	DISTRIBUTION EXPENSES											
E	12	Operation											
E	13	Account 577 - Energy Storage Expense - Operation											
E	14	577.1 Operation Supervision and Engineering	SALWAGDO			0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	SALWAGDO			0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	ENERGY1			0	0	0	0	0	0	0	0
E	17	577.4 Rents	DISTPLT			0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	DISTPLT			0	0	0	0	0	0	0	0
E	19	Total Account 577				0	0	0	0	0	0	0	0
E	20	580-Supervision	SALWAGDO			577	353	73	90	2	50	3	6
E	21	581-Load Dispatch	DISTPLT			0	0	0	0	0	0	0	0
E	22	582-Station Equipment	PLT_362			7,147	2,980	912	1,328	46	1,747	102	33
E	23	583-Overhead Lines	OHDIST			17,832	9,779	2,427	3,115	93	2,060	120	239
E	24	584-Underground Lines	UGDIST			11,466	5,978	1,513	1,970	60	1,706	100	139

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
E	25	585-Street Lighting	PLT_3713			0	0	0	0	0	0	0	0
E	26	586-Metering	CMETERS			6,490	4,344	704	1,099	25	314	4	0
E	27	587-Customer Installations	CUST			13,367	10,418	1,625	1,203	3	22	0	97
E	28	588-Miscellaneous	DISTPLT			89,634	46,724	11,924	16,925	420	11,582	668	1,392
E	29	589-Rents	DISTPLT			4,105	2,140	546	775	19	530	31	64
E	30	Total Distribution Operation				150,619	82,715	19,723	26,505	668	18,010	1,027	1,970
E													
E	31	Maintenance											
E	32	578 - Energy Storage Expense - Maintenance											
E	33	578.1 Maintenance Supervision and Engineering (Major Only)	SALWAGDM			0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structures (Major Only)	MX_578.2			0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	MX_578.3			0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	MX_578.4			0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Only)	MX_578.5			0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Plant (Major Only)	MX_578.6			0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor Only)	MX_578.7			0	0	0	0	0	0	0	0
E	40	Total Account 578				0	0	0	0	0	0	0	0
E	41	590-Supervision	SALWAGDM			0	0	0	0	0	0	0	0
E	42	591-Structures	PLT_361			7,254	3,024	925	1,348	47	1,773	104	33
E	43	592-Station Equipment											
E	44	592.1-Structures and Equipment	PLT_362			17,283	7,205	2,204	3,212	111	4,225	247	79
E	45	592.2-Computer Hardware	PLT_362			0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	PLT_362			0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	PLT_362			0	0	0	0	0	0	0	0
E	48	Total Account 592				17,283	7,205	2,204	3,212	111	4,225	247	79
E	49	593-Overhead Lines	OHDIST			202,158	110,859	27,511	35,316	1,051	23,349	1,363	2,710
E	50	594-Underground Lines	UGDIST			36,494	19,028	4,816	6,269	190	5,431	317	443
E	51	595-Transformers	PLT_368			2,640	1,498	458	668	0	0	0	16
E	52	596-Street Lighting	PLT_373			1,828	0	0	0	0	0	0	1,828
E	53	597-Metering	CMETERS			0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	DISTPLT			17,638	9,194	2,346	3,330	83	2,279	131	274
E	55	Total Distribution Maintenance				285,295	150,808	38,261	50,143	1,481	37,057	2,161	5,383
E													
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES				435,914	233,524	57,984	76,648	2,149	55,067	3,189	7,353
E	57	TOTAL PURCHASED POWER O&M EXPENSES				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
E	58	TOTAL TRANSMISSION O&M EXPENSES				225,704	123,666	30,895	44,222	616	25,264	1,006	34
E													
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)				2,175,410	1,333,837	332,848	335,552	4,356	156,618	4,195	8,005
E													
E													
E													
E													
E													
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**											
E													
E	61	CUSTOMER ACCOUNTS EXPENSES											
E	62	901-Supervision	SALWAGCA			0	0	0	0	0	0	0	0
E	63	902-Meter Reading	CMETERS			250	167	27	42	1	12	0	0
E	64	903-Customer Records and Collection Expense	CUSTREC			102,973	78,676	12,399	7,331	452	3,680	20	416
E	65	904-Uncollectible Accounts	EXP_904			58,726	42,597	9,458	6,308	12	345	0	4
E	66	905-Miscellaneous CA	CUSTCAM			6,859	5,346	834	617	1	11	0	50
E	67	TOTAL CUSTOMER ACCTS EXPENSE				168,808	126,786	22,718	14,299	466	4,048	20	469
E													
E													
E	68	CUSTOMER SERVICE EXPENSES											
E	69	907-Supervision	SALWAGCS			0	0	0	0	0	0	0	0

PECO Energy Company
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Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
E	70	908-Customer Assistance	CUSTASST			35,434	29,258	4,563	1,495	4	27	0	88
E	71	909-Informational Advertisement	CUSTADVT			2,438	1,900	296	219	1	4	0	18
E	72	910-Miscellaneous CS	CUSTCSM			935	729	114	84	0	2	0	7
E	73	TOTAL CUSTOMER SERVICE EXPENSE				38,807	31,887	4,973	1,798	4	32	0	112
E													
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	CUSTSALES			734	0	0	266	10	458	0	0
E													
E	75	TOTAL OPER & MAINT EXCL A&G				2,383,760	1,492,511	360,539	351,916	4,836	161,157	4,216	8,586
E													
E	76	ADMINISTRATIVE & GENERAL EXPENSE											
E	77	920-Administrative Salaries	SALWAGES			39,282	23,785	5,080	5,656	183	3,949	209	420
E	78	921-Office Supplies & Expense	SALWAGES			4,273	2,587	553	615	20	430	23	46
E	79	923-Outside Service Employed	SALWAGES			101,338	61,359	13,106	14,591	471	10,188	540	1,082
E	80	924-Property Insurance	DGPLT			970	507	129	182	5	125	7	15
E	81	925-Injuries and Damages	SALWAGES			18,625	11,277	2,409	2,682	87	1,873	99	199
E	82	926-Employee Pensions & Benefits	SALWAGES			32,797	19,858	4,242	4,722	153	3,297	175	350
E	83	928-Regulatory Commission	PROPREV			9,851	5,827	1,415	1,573	31	896	38	71
E	84	929-Duplicate Charges-Credit	PROPREV			(2,075)	(1,228)	(298)	(331)	(7)	(189)	(8)	(15)
E	85	930.2-Miscellaneous General											
E	86	R/RH	SREVRRH			0	0	0	0	0	0	0	0
E	87	GS	SREVGS			0	0	0	0	0	0	0	0
E	88	GS/PD/HT	CUSTCI			0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	CTCREALLR			0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	CTCREALLCI			0	0	0	0	0	0	0	0
E	91	All Other	PROPREV			1,487	880	214	237	5	135	6	11
E	92	Total 930.2-Miscellaneous General				1,487	880	214	237	5	135	6	11
E	93	935-Maintenance of General Plant											
E	94	935-Maintenance of General Plant	GENLPLT			10,000	6,055	1,293	1,440	47	1,005	53	107
E	95	935.1-Maintenance of Computer Hardware	GENLPLT			0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	GENLPLT			0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	GENLPLT			0	0	0	0	0	0	0	0
E	98	Total Account 935				10,000	6,055	1,293	1,440	47	1,005	53	107
E	99	TOTAL A&G EXPENSE				216,547	130,906	28,142	31,368	993	21,710	1,143	2,286
E													
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**				860,811	523,104	113,818	124,379	3,623	81,315	4,352	10,220
E													
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**				2,600,307	1,623,417	388,681	383,283	5,830	182,866	5,358	10,872
E													
E													
E													
E													
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**											
D													
D	2	INTANGIBLE PLANT EXPENSE	INTPLT			38,758	25,825	4,223	6,580	151	1,939	27	12
D													
D	3	TRANSMISSION PLANT EXPENSE	TRANPLT			0	0	0	0	0	0	0	0
D													
D	4	DISTRIBUTION PLANT EXPENSE											
D	5	360-Land & Land Rights	PLT_360			0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	PLT_361			6,864	2,862	875	1,276	44	1,678	98	31
D	7	362-Station Equipment	PLT_362			25,182	10,498	3,212	4,680	162	6,156	359	115
D	8	363-Computer HW SW and Equipment	PLT_363			38,928	16,229	4,965	7,235	250	9,516	555	178
D	9	364-Poles,Towers & Fixtures	PLT_364			47,519	26,059	6,467	8,301	247	5,488	320	637
D	10	365-Overhead Conductors & Devices	PLT_365			62,747	34,409	8,539	10,962	326	7,247	423	841
D	11	366-Underground Conduit	PLT_366			23,194	12,093	3,061	3,984	121	3,452	201	282
D	12	367-Underground Conductors & Devices	PLT_367			60,171	31,373	7,941	10,336	313	8,954	523	731

PECO Energy Company
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Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
D	13	368-Line Transformers	PLT_368			28,173	15,983	4,890	7,125	0	0	0	175
D	14	369-Services	PLT_369			8,825	4,801	749	3,211	8	57	0	0
D	15	370-Meters	PLT_370			20,615	13,798	2,236	3,492	80	998	11	0
D	16	371-Installation on Customer Premises	PLT_371			0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	PLT_373			1,551	0	0	0	0	0	0	1,551
D	18	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR			0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE				323,772	168,106	42,934	60,603	1,551	43,546	2,491	4,540
D													
D	20	ENERGY STORAGE PLANT EXPENSE	ENSTORPLT			0	0	0	0	0	0	0	0
D													
D	21	GENERAL PLANT EXPENSE	GENLPLT			45,292	27,423	5,858	6,521	211	4,554	241	484
D													
D	22	BESS DEPRECIATION	CUSTADVRRH			200	160	40	0	0	0	0	0
D													
D	23	REG ASSET AMORTIZATION	TOTPLT			16,572	8,662	2,203	3,117	78	2,133	123	256
D													
D													
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**				424,593	230,177	55,258	76,821	1,990	52,172	2,882	5,292
D													
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TO	1	**OTHER OPERATING EXPENSES**											
TO													
TO	2	**TAXES OTHER THAN INCOME TAXES**											
TO	3	**GENERAL TAXES**											
TO	4	PURTA Taxes	PLT_3601			6,863	2,861	875	1,276	44	1,678	98	31
TO	5	Capital Stock	CAPSTOCK			0	0	0	0	0	0	0	0
TO	6	Payroll Related	SALWAGES			15,017	9,093	1,942	2,162	70	1,510	80	160
TO	7	Other Property Basis Adjustment (CIAC/ICM) - Federal	TOTPLT			0	0	0	0	0	0	0	0
TO	8	Other Property Basis Adjustment (CIAC/ICM) - State	TOTPLT			0	0	0	0	0	0	0	0
TO	9	PA & Local Use Tax	PROPREV			2,353	1,392	338	376	7	214	9	17
TO	10	PA Property Tax	TOTPLT			6,285	3,285	836	1,182	29	809	47	97
TO	11	PA Corporate LoanTax	TOTPLT			0	0	0	0	0	0	0	0
TO	12	Total General Taxes				30,519	16,631	3,991	4,996	151	4,210	234	306
TO													
TO													
TO	13	**GROSS RECEIPTS TAX**											
TO													
TO	14	**PURCHASED POWER**											
TO	15	Retail Revenue				1,612,994	1,040,649	259,956	228,750	1,695	81,286	0	658

PECO Energy Company
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Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
TO	16	Forfeited Discounts				0							
TO	17	Less: Bad Debt				0							
TO	18	Total Purchased Power Revenue				1,612,994	1,040,649	259,956	228,750	1,695	81,286	0	658
TO	19	Total Purchased Power at 5.90% GRT Rate				95,167	61,398	15,337	13,496	100	4,796	0	39
TO													
TO	20	**TRANSMISSION**											
TO	21	Retail Revenue				241,020	132,058	32,991	47,223	658	26,979	1,074	37
TO	22	Forfeited Discounts				0							
TO	23	Less: Bad Debt				0							
TO	24	Total Transmission Revenue				241,020	132,058	32,991	47,223	658	26,979	1,074	37
TO	25	Total Transmission at 5.90% GRT Rate				14,220	7,791	1,946	2,786	39	1,592	63	2
TO													
TO	26	**DISTRIBUTION**											
TO	27	Retail Revenue				1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
TO	28	Forfeited Discounts				18,527	13,439	2,984	1,990	4	109	0	1
TO	29	Less: Bad Debt				58,726	42,597	9,458	6,308	12	345	0	4
TO	30	Total Distribution Revenue				1,940,393	1,105,378	212,882	339,920	9,850	233,857	9,662	28,843
TO	31	Total Distribution at 5.90% GRT Rate				114,483	65,217	12,560	20,055	581	13,798	570	1,702
TO													
TO	32	TOTAL GROSS RECEIPTS TAX				223,870	134,407	29,844	36,338	720	20,185	633	1,743
TO													
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES				95,167	61,398	15,337	13,496	100	4,796	0	39
TO	34	TOTAL TRANSMISSION TOIT EXPENSES				14,220	7,791	1,946	2,786	39	1,592	63	2
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES				145,002	81,849	16,551	25,051	732	18,008	804	2,008
TO													
TO	36	**TOTAL TAXES OTHER THAN INCOME**				254,389	151,038	33,835	41,333	871	24,396	867	2,049
TO													
TO													
TO													
TO													
TO													
TO													
TO													
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**											
TI													
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES				2,034,528	1,168,680	227,226	352,309	9,992	237,054	9,864	29,401
TI	3	LESS:											
TI	4	OPERATION & MAINTAINENCE EXPENSE				860,811	523,104	113,818	124,379	3,623	81,315	4,352	10,220
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE				424,593	230,177	55,258	76,821	1,990	52,172	2,882	5,292
TI	6	TAXES OTHER THAN INCOME TAXES				145,002	81,849	16,551	25,051	732	18,008	804	2,008
TI	7	NET OPERATING INCOME BEFORE TAXES				604,121	333,551	41,599	126,058	3,647	85,559	1,826	11,882
TI	8	LESS:											
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)				241,905	128,265	32,442	44,183	1,149	30,876	1,749	3,242
TI													
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**				362,216	205,286	9,157	81,875	2,498	54,683	77	8,640
TI													
TI													
TI	11	**CALCULATION OF PA STATE INCOME TAXES**											
TI	12	BASE TAXABLE INCOME				362,216	205,286	9,157	81,875	2,498	54,683	77	8,640
TI	13	LESS:											
TI	14	State Tax Depreciation (Over) Under Book	TOTPLT			(53,322)	(27,872)	(7,089)	(10,029)	(250)	(6,863)	(395)	(823)
TI	15	Other Adjustment (state calc.)	TOTPLT			106,410	55,621	14,148	20,014	499	13,696	789	1,643
TI	16	Repair Allowance Deduction	TOTPLT			377,000	197,061	50,124	70,909	1,767	48,522	2,796	5,821
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME				(67,872)	(19,524)	(48,025)	980	482	(671)	(3,112)	1,999
TI	18	NOL Utilization	TOTPLT			39,035	20,404	5,190	7,342	183	5,024	289	603
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**				(2,016)	61	(2,994)	582	46	304	(197)	182
TI	20	**PLUS:**											

PECO Energy Company
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Sch.	Line No.	Description	Allocator	(E)	(F)	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)			(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
TI	21	**DEFERRED STATE INCOME TAXES**											
TI	22	State Deferred Taxes	TOTPLT			53,652	28,044	7,133	10,091	252	6,905	398	828
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RATE**				3,750	1,960	499	705	18	483	28	58
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**				1,735	2,022	(2,496)	1,287	64	787	(169)	240
TI													
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**											
TI	26	BASE TAXABLE INCOME				362,216	205,286	9,157	81,875	2,498	54,683	77	8,640
TI	27	LESS:											
TI	28	PA State Income Taxes				(2,016)	61	(2,994)	582	46	304	(197)	182
TI	29	Federal Tax Depreciation (Over) Under Book	TOTPLT			(44,620)	(23,323)	(5,933)	(8,393)	(209)	(5,743)	(331)	(689)
TI	30	Other Adjustment (federal calc.)	TOTPLT			119,882	62,663	15,939	22,548	562	15,429	889	1,851
TI	31	Repair Allowance Deduction	TOTPLT			377,000	197,061	50,124	70,909	1,767	48,522	2,796	5,821
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME				(88,030)	(31,176)	(47,979)	(3,772)	331	(3,830)	(3,079)	1,475
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**				(18,486)	(6,547)	(10,076)	(792)	70	(804)	(647)	310
TI	34	**PLUS:**											
TI	35	**DEFERRED FEDERAL INCOME TAXES**											
TI	36	Federal Deferred Taxes	TOTPLT			159,385	83,312	21,191	29,978	747	20,514	1,182	2,461
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX RATE**				33,471	17,495	4,450	6,295	157	4,308	248	517
TI	38	**LESS:**											
TI	39	**OTHER TAX ADJUSTMENTS**											
TI	40	Electric Plant	TOTPLT			0	0	0	0	0	0	0	0
TI	41	Common Plant	SALWAGES			0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	EBT			(17)	(10)	(0)	(4)	(0)	(3)	(0)	(0)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**				15,002	10,958	(5,625)	5,507	227	3,506	(398)	827
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**				16,736	12,980	(8,121)	6,794	291	4,293	(568)	1,067
TI													
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**											
TI													
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**											
TI	47	PURCHASED POWER OPERATING REVENUES				1,612,994	1,040,649	259,956	228,750	1,695	81,286	0	658
TI	48	LESS:											
TI	49	OPERATION & MAINTAINENCE EXPENSE				1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
TI	50	TAXES OTHER THAN INCOME TAXES				95,167	61,398	15,337	13,496	100	4,796	0	39
TI	51	NET OPERATING INCOME BEFORE TAXES				4,036	2,604	650	572	4	203	0	2
TI	52	LESS:											
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)				2,034	1,312	328	288	2	103	0	1
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**				2,001	1,291	323	284	2	101	0	1
TI	55	LESS:											
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99% TAX RATE**				140	90	23	20	0	7	0	0
TI	57	EQUALS:											
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00% TAX RATE**				391	252	63	55	0	20	0	0
TI	59	Additional Purchase Power Expense NOL				0	0	0	0	0	0	0	0
TI													
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**											
TI	61	TRANSMISSION OPERATING REVENUES				241,020	132,058	32,991	47,223	658	26,979	1,074	37
TI	62	LESS:											
TI	63	OPERATION & MAINTAINENCE EXPENSE				225,704	123,666	30,895	44,222	616	25,264	1,006	34
TI	64	TAXES OTHER THAN INCOME TAXES				14,220	7,791	1,946	2,786	39	1,592	63	2
TI	65	NET OPERATING INCOME BEFORE TAXES				1,096	600	150	215	3	123	5	0
TI	66	LESS:											
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)				283	135	20	54	2	69	3	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**				812	465	130	160	1	54	2	(0)
TI	69	LESS:											
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% TAX RATE**				57	32	9	11	0	4	0	(0)
TI	71	EQUALS:											
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% TAX RATE**				159	91	25	31	0	10	0	(0)
TI													

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator			Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
TI	73	**TOTAL PA INCOME TAX EXPENSE**				1,931	2,145	(2,464)	1,318	64	798	(169)	240
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**				15,551	11,301	(5,537)	5,594	227	3,536	(398)	827
TI	75	**TOTAL INCOME TAX EXPENSE**				17,483	13,446	(8,001)	6,912	292	4,334	(567)	1,067
TI													
TI													
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PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027

Sch.	Line No.	Description	Allocator			Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
TI													
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**											
RRW													
RRW	2	Present Rates											
RRW													
RRW	3	Rate Base ($)				10,847,754	5,751,782	1,454,776	1,981,310	51,508	1,384,552	78,424	145,401
RRW	4	Net Operating Income at Present Rates ($)				587,385	320,571	49,719	119,264	3,356	81,266	2,394	10,816
RRW	5	Rate of Return at Present Rates				5.41%	5.57%	3.42%	6.02%	6.52%	5.87%	3.05%	7.44%
RRW	6	Relative Rate of Return				1.00	1.03	0.63	1.11	1.20	1.08	0.56	1.37
RRW	7	Sales Revenue at Present Rates ($)				1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
RRW	8	Revenue at Present Rates ($/KWH)				$0.0544	$0.1000	$0.0782	$0.0456	$0.0342	$0.0169	$0.0207	$0.2118
RRW	9	Revenue Required - $/MO/CUST				$95.42	$70.13	$86.95	$184.30	$2,202.59	$7,009.62	$20,778.63	$191.58
RRW	10	Sales Revenue Required - $/KW				$33.12	$0.00	$0.00	$13.78	$13.39	$7.24	$5.54	$0.00
RRW													
RRW	11	Proposed Rate of Return											
RRW													
RRW	12	Proposed Rate of Return				8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR				876,500	464,745	117,546	160,090	4,162	111,872	6,337	11,748
RRW	14	Sales Revenue Required at Proposed ROR - Distribution				2,403,895	1,345,635	318,658	404,014	11,039	278,904	15,433	30,211
RRW	15	Revenue Deficiency Sales Revenue				423,304	211,099	99,301	59,776	1,180	44,810	5,771	1,366
RRW	16	Percent Increase Required				21.37%	18.61%	45.27%	17.36%	11.97%	19.14%	59.73%	4.73%
RRW	17	Annual Booked kWh Sales				36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
RRW	18	Sales Revenue Required $/KWH				$0.0660	$0.1186	$0.1136	$0.0535	$0.0383	$0.0202	$0.0330	$0.2219
RRW	19	Revenue Deficiency $/KWH				$0.0116	$0.0186	$0.0354	$0.0079	$0.0041	$0.0032	$0.0124	$0.0100
RRW	20	Sales Revenue Req. at Proposed ROR - Energy				1,618,585	1,044,256	260,857	229,543	1,701	81,568	0	660
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission				241,232	132,078	32,928	47,259	664	27,184	1,082	38

PECO Exhibit JD-2:
Total Class Allocation
Allocator Development

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Allocation Development and Ratio Tables

Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Allocation Development Tables											
	Total-Cost-of-Service Level Allocators											
1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATOR**											
2	**PRODUCTION OTHER SALARIES & WAGES EXPENSE**											
3	555-Purchased Power	OX_PROD			0	0	0	0	0	0	0	0
4	TOTAL PRODUCTION OTHER SAL & WAG EXP				0	0	0	0	0	0	0	0
5	**TRANSMISSION SALARIES & WAGES EXPENSE**											
6	Operation	OX_TRAN			0	0	0	0	0	0	0	0
7	Maintenance	MX_TRAN			0	0	0	0	0	0	0	0
8	TOTAL TRANSMISSION				0	0	0	0	0	0	0	0
9	**DISTRIBUTION SALARIES & WAGES EXPENSE**											
10	Operation											
11	583-Overhead Lines	OX_583			2,927	1,605	398	511	15	338	20	39
12	584-Underground Lines	OX_584			3,079	1,605	406	529	16	458	27	37
13	586-Metering	OX_586			2,686	1,798	291	455	10	130	1	0
14	587-Customer Installations	OX_587			6,460	5,035	785	581	1	10	0	47
15	588-Miscellaneous	OX_588			8,424	4,391	1,121	1,591	40	1,089	63	131
16	Total Operation				23,577	14,435	3,002	3,667	83	2,025	111	254
17	Maintenance											
18	591-Structures	MX_591			1,581	659	202	294	10	387	23	7
19	592-Station Equipment	MX_592			8,312	3,465	1,060	1,545	53	2,032	119	38
20	593-Overhead Lines	MX_593			47,503	26,050	6,464	8,298	247	5,486	320	637
21	594-Underground Lines	MX_594			16,141	8,416	2,130	2,773	84	2,402	140	196
22	595-Transformers	MX_595			805	457	140	204	0	0	0	5
23	596-Street Lighting	MX_596			147	0	0	0	0	0	0	147
24	598-Miscellaneous	MX_598			3,377	1,760	449	638	16	436	25	52
25	Total Maintenance				77,866	40,807	10,445	13,751	410	10,743	627	1,083
26	TOTAL DISTRIBUTION				101,443	55,241	13,447	17,418	493	12,768	738	1,337
27	**CUSTOMER ACCOUNTS SAL & WAGES EXP**											
28	903-Customer Records and Collection Expense	CUSTREC			35,751	27,315	4,305	2,545	157	1,278	7	144
29	905-Miscellaneous CA	CUSTCAM			985	768	120	89	0	2	0	7
30	**TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP**				36,736	28,083	4,425	2,634	157	1,279	7	151
31	**CUSTOMER SERVICE SAL & WAGES EXP**											
32	908-Customer Assistance	CUSTASST			1,187	980	153	50	0	1	0	3
33	909-Advertisement	CUSTADVT			0	0	0	0	0	0	0	0
34	910-Miscellaneous CS	CUSTCSM			0	0	0	0	0	0	0	0
35	TOTAL CUSTOMER SERVICE SAL & WAGES EXP				1,187	980	153	50	0	1	0	3
36	**SALES EXPENSE (ACCT 912&916)**	OX_CS			493	405	63	23	0	0	0	1
37	**ADMINISTRATIVE & GENERAL SALARIES & WAGES EXP**	SALWAGXAG			47,418	28,684	6,133	6,840	221	4,780	253	507
38	**TOT OPER & MAINTENANCE LABOR**				187,276	113,393	24,220	26,965	871	18,828	998	2,000
	Allocation Development Tables											
39	**Total-Cost-of-Service Level Allocators (Cont'd)**											
40	**INTERNALLY DEVELOPED ALLOCATORS**											
41	**Plant Related**											
42	Intangible Plant	INTPLT			7,056	4,702	769	1,198	27	353	5	2
43	Transmission Plant in Service	TRANPLT			0	0	0	0	0	0	0	0
44	Distribution Plant in Service	DISTPLT			12,935,381	6,742,843	1,720,765	2,442,467	60,652	1,671,385	96,422	200,847
45	Distribution plant in Service - R and RH only	DISTPLTRRH			8,463,608	6,742,843	1,720,765	0	0	0	0	0
46	Energy Storage Plant in Service	ENSTORPLT			0	0	0	0	0	0	0	0
47	General Plant in Service	GENLPLT			212,149	128,453	27,437	30,546	987	21,329	1,131	2,266

PECO Energy Company
Electric Class Cost of Service Study ($000s)
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Allocation Development and Ratio Tables

Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
48	Total Electric Plant In Service	TOTPLT			13,154,586	6,875,998	1,748,971	2,474,212	61,666	1,693,067	97,558	203,115
49	Distribution Plant Excl Asset Retirement	DISTPLTXAR			12,600,531	6,602,814	1,678,035	2,380,222	58,507	1,590,006	91,672	199,274
50	Total Transmission and Distribution Plant	TDPLT			12,935,381	6,742,843	1,720,765	2,442,467	60,652	1,671,385	96,422	200,847
51	Total Distribution and General Plant	DGPLT			13,147,530	6,871,296	1,748,202	2,473,014	61,639	1,692,714	97,553	203,113
52	Rate Base	RATEBASE			10,951,677	5,816,710	1,470,364	1,996,682	51,688	1,392,247	78,538	145,447
53	Account 360	PLT_360			56,497	23,553	7,206	10,500	363	13,811	806	258
54	Account 361	PLT_361			319,617	133,247	40,764	59,402	2,054	78,130	4,561	1,459
55	Account 362	PLT_362			1,387,485	578,439	176,962	257,867	8,918	339,169	19,798	6,333
56	Account 363	PLT_363			330,833	137,924	42,195	61,486	2,126	80,872	4,721	1,510
57	Account 364	PLT_364			1,925,544	1,055,927	262,039	336,381	10,009	222,394	12,981	25,814
58	Account 365	PLT_365			2,730,320	1,497,248	371,557	476,970	14,192	315,343	18,407	36,602
59	Account 366	PLT_366			1,362,310	710,301	179,785	234,023	7,094	202,731	11,834	16,542
60	Account 367	PLT_367			2,654,822	1,384,209	350,359	456,056	13,825	395,075	23,061	32,237
61	Account 368	PLT_368			1,145,141	649,661	198,751	289,618	0	0	0	7,112
62	Account 369	PLT_369			516,670	281,055	43,828	187,976	450	3,361	0	0
63	Account 370	PLT_370			413,020	276,443	44,799	69,960	1,600	19,993	225	0
64	Account 371	PLT_371			16,772	12,731	1,985	1,470	0	0	0	586
65	Account 373	PLT_373			72,331	0	0	0	0	0	0	72,331
66	Distribution Overhead Plant in Service	OHDIST			4,655,864	2,553,175	633,595	813,351	24,201	537,737	31,388	62,416
67	Distribution Underground Plant in Service	UGDIST			4,017,133	2,094,509	530,145	690,079	20,920	597,806	34,895	48,780
68	Accounts 360 & 361	PLT_3601			376,114	156,801	47,970	69,902	2,417	91,940	5,367	1,717
69	Accounts 371 & 373	PLT_3713			89,104	12,731	1,985	1,470	0	0	0	72,917
70	Distribution Plant Accounts 364-367	DPLT_364-367			8,672,997	4,647,685	1,163,740	1,503,430	45,121	1,135,543	66,283	111,195
	Allocation Development Tables											
71	**Total-Cost-of-Service Level Allocators (Cont'd)**											
72	**INTERNALLY DEVELOPED ALLOCATORS**											
73	**Production Expense Related**											
74	Account 555	OX_555			1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
75	O&M Expense Production Other	OX_PROD			1,513,792	976,647	243,968	214,682	1,590	76,287	0	618
76	Salaries and Wages Production Operation	SALWAGPO			0	0	0	0	0	0	0	0
77	**Transmission Expense Related**											
78	Transmission Operation Expense	OX_TRAN			225,704	123,666	30,895	44,222	616	25,264	1,006	34
79	Transmission Maintenance Expense	MX_TRAN			0	0	0	0	0	0	0	0
80	Transmission Salaries & Wages Accounts 511-567	SALWAGTO			0	0	0	0	0	0	0	0
81	Transmission Salaries & Wages Accounts 569-574	SALWAGTM			0	0	0	0	0	0	0	0
82	**Distribution Expense Related**											
83	Account 580	OX_580			577	353	73	90	2	50	3	6
84	Account 581	OX_581			0	0	0	0	0	0	0	0
85	Account 582	OX_582			7,147	2,980	912	1,328	46	1,747	102	33
86	Account 583	OX_583			17,832	9,779	2,427	3,115	93	2,060	120	239
87	Account 584	OX_584			11,466	5,978	1,513	1,970	60	1,706	100	139
88	Account 585	OX_585			0	0	0	0	0	0	0	0
89	Account 586	OX_586			6,490	4,344	704	1,099	25	314	4	0
90	Account 587	OX_587			13,367	10,418	1,625	1,203	3	22	0	97
91	Account 588	OX_588			89,634	46,724	11,924	16,925	420	11,582	668	1,392
92	Account 589	OX_589			4,105	2,140	546	775	19	530	31	64
93	Account 578.2	MX_578.2			0	0	0	0	0	0	0	0
94	Account 578.3	MX_578.3			0	0	0	0	0	0	0	0
95	Account 578.4	MX_578.4			0	0	0	0	0	0	0	0
96	Account 578.5	MX_578.5			0	0	0	0	0	0	0	0
97	Account 578.6	MX_578.6			0	0	0	0	0	0	0	0

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Allocation Development and Ratio Tables

Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
98	Account 578.7	MX_578.7			0	0	0	0	0	0	0	0
93	Account 591	MX_591			7,254	3,024	925	1,348	47	1,773	104	33
99	Account 592	MX_592			17,283	7,205	2,204	3,212	111	4,225	247	79
100	Account 593	MX_593			202,158	110,859	27,511	35,316	1,051	23,349	1,363	2,710
101	Account 594	MX_594			36,494	19,028	4,816	6,269	190	5,431	317	443
102	Account 595	MX_595			2,640	1,498	458	668	0	0	0	16
103	Account 596	MX_596			1,828	0	0	0	0	0	0	1,828
104	Account 597	MX_597			0	0	0	0	0	0	0	0
105	Account 598	MX_598			17,638	9,194	2,346	3,330	83	2,279	131	274
106	O&M Accounts 581-589	OX_DIST			150,042	82,362	19,650	26,415	666	17,961	1,024	1,963
107	O&M Accounts 591-598	MX_DIST			302,578	158,014	40,465	53,355	1,592	41,282	2,408	5,462
	Allocation Development Tables											
108	**Total-Cost-of-Service Level Allocators (Cont'd)**											
109	**INTERNALLY DEVELOPED ALLOCATORS**											
110	**Customer Distribution Expense Related**											
111	Account 902	OX_902			250	167	27	42	1	12	0	0
112	Account 903	OX_903			102,973	78,676	12,399	7,331	452	3,680	20	416
113	Account 904	OX_904			58,726	42,597	9,458	6,308	12	345	0	4
114	O&M Accounts 902-905	OX_CA			168,808	126,786	22,718	14,299	466	4,048	20	469
115	Account908	OX_908			35,434	29,258	4,563	1,495	4	27	0	88
116	Account909	OX_909			2,438	1,900	296	219	1	4	0	18
117	Account910	OX_910			935	729	114	84	0	2	0	7
118	O&M Accounts 908-910	OX_CS			38,807	31,887	4,973	1,798	4	32	0	112
119	Accounts 901-910	X_CACS			207,615	158,674	27,691	16,097	471	4,080	21	581
120	Total O&M less Purchased Power	OMXPP			1,085,781	646,770	144,713	168,336	4,229	106,121	5,358	10,254
121	Total O&M less PP less Payroll less Pension	OMXPPPP			865,708	513,519	116,251	136,649	3,206	83,995	4,185	7,904
122	**Salaries and Wages Expense Related**											
123	Salaries & Wages Accounts 581-589	SALWAGDO			23,577	14,435	3,002	3,667	83	2,025	111	254
124	Salaries & Wages Accounts 591-598	SALWAGDM			77,866	40,807	10,445	13,751	410	10,743	627	1,083
125	Salaries & Wages Accounts 902-905	SALWAGCA			36,736	28,083	4,425	2,634	157	1,279	7	151
126	Salaries & Wages Accounts 908-910	SALWAGCS			1,187	980	153	50	0	1	0	3
127	Salaries & Wages Excluding Admin & Gen	SALWAGXAG			139,366	84,304	18,025	20,102	650	14,048	745	1,491
128	Total Salaries and Wages Expense	SALWAGES			187,276	113,393	24,220	26,965	871	18,828	998	2,000
129	Base Taxable Income	EBT			362,216	205,286	9,157	81,875	2,498	54,683	77	8,640
130	**REVENUES AND BILLING DETERMINANTS**											
131	Base Rate Sales Revenue	SALESREV			1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
132	Residential	SREVRES			1,134,536	1,134,536	0	0	0	0	0	0
133	Residential Heating	SREVRH			219,357	0	219,357	0	0	0	0	0
134	General Service	SREVGS			344,238	0	0	344,238	0	0	0	0
135	Primary Distribution	SREVPRID			9,859	0	0	0	9,859	0	0	0
136	High Tension	SREVHT			234,093	0	0	0	0	234,093	0	0
137	Electric Propulsion	SREVEP			9,662	0	0	0	0	0	9,662	0
138	Lighting	SREVLCUST			28,846	0	0	0	0	0	0	28,846
139	Available 1	SREVAV1			0	0	0	0	0	0	0	0
140	Available 2	SREVAV2			0	0	0	0	0	0	0	0
141	Available 3	SREVAV3			0	0	0	0	0	0	0	0
142	Available 4	SREVAV4			0	0	0	0	0	0	0	0
143	Available 5	SREVAV5			0	0	0	0	0	0	0	0
144	Available 6	SREVAV6			0	0	0	0	0	0	0	0
145	Available 7	SREVAV7			0	0	0	0	0	0	0	0
146	Available 8	SREVAV8			0	0	0	0	0	0	0	0

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Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
147	Available 9	SREVAV9			0	0	0	0	0	0	0	0
148	Available 10	SREVAV10			0	0	0	0	0	0	0	0
149	R/RH	SREVRRH			1,353,893	1,134,536	219,357	0	0	0	0	0
150	GS/PD/HT	SREVGSPDHT			588,190	0	0	344,238	9,859	234,093	0	0
151	PD/HT	SREVPDHT			243,952	0	0	0	9,859	234,093	0	0
152	Proposed Rate Sales Revenue	PROPREV			4,263,712	2,521,970	612,443	680,816	13,403	387,656	16,515	30,909
153	Capital Stock	CAPSTOCK			8,709,149	4,698,984	1,180,707	1,577,514	37,535	1,040,361	57,036	117,012
154	**PRESENT REVENUES/EXPENSES FROM SALES INPUT**											
155	Sales of Electricity Revenues - Distribution				1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
156	Sales of Electricity Revenues - Transmission				241,020	132,058	32,991	47,223	658	26,979	1,074	37
157	**Allocation of Net Write-Offs, Cust. Advances, and POR**											
158	Net Write-Offs	EXP_904			140,276	101,751	22,593	15,069	29	825	0	9
159	Customer Advances for Construction	CUSTADV			8,672,997	4,647,685	1,163,740	1,503,430	45,121	1,135,543	66,283	111,195
160	Customer Advances for Construction - R & RH	CUSTADVRRH			5,811,425	4,647,685	1,163,740	0	0	0	0	0
161	Purchase of Receivables	POR			1,428,686	329,053	81,347	523,862	10,016	480,428	0	3,980
162	**BILLING DETERMINATE INPUTS**											
163	Number of Customer Bills				20,756,557	16,177,098	2,522,699	1,867,855	4,476	33,396	465	150,568
164	Annual MWh Sales @ Meter				36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
165	Annual MW - Billed				59,800	0	0	24,978	736	32,343	1,743	0
166	**RATE OF RETURN**											
167	Rate of Return (Equalized)				8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
	Allocation Development Tables Total-Cost-of-Service & (Sub)Function Level Allocators											
2	**EXTERNALLY DEVELOPED ALLOCATORS**											
3	**DEMAND**											
4	DEMAND - PRODUCTION RELATED											
5	Demand Production	DPROD			0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	DEMAND - TRANSMISSION RELATED											
7	Demand Transmission (1 Coincident Peak)	DTRAN			8,379,496	4,007,744	584,624	1,606,611	55,471	2,044,013	75,331	5,701
8	Demand Transmission (Revenue)	DTRANR			241,020	132,058.014	32,991.390	47,223.029	657.975	26,978.551	1,074.485	36.789
9	DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand)											
10	Demand Distribution Primary High Tension	DDISPHT			9,667,374	4,030,305	1,232,991	1,796,705	62,135	2,363,175	137,941	44,122
11	Demand Distribution Primary High Tension - Residential Only	DDISPHTR			5,263,296	4,030,305	1,232,991	0	0	0	0	0
12	Demand Distribution Primary Overhead Lines	DDISTPOL			7,166,258	4,030,305	1,232,991	1,796,705	62,135	0	0	44,122
13	Demand Distribution Primary Underground Lines	DDISTPUL			7,166,258	4,030,305	1,232,991	1,796,705	62,135	0	0	44,122

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Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
14	Demand Distribution Secondary Overhead Lines	DDISTSOL			7,104,123	4,030,305	1,232,991	1,796,705	0	0	0	44,122
15	Demand Distribution Secondary Underground Lines	DDISTSUL			7,104,123	4,030,305	1,232,991	1,796,705	0	0	0	44,122
16	Demand Distribution Overhead Line Transformers	DDISTSOT			7,104,123	4,030,305	1,232,991	1,796,705	0	0	0	44,122
17	Demand Distribution Underground Line Transformers	DDISTSUT			7,104,123	4,030,305	1,232,991	1,796,705	0	0	0	44,122
	Allocation Development Tables											
	Total-Cost-of-Service											
	&											
18	**(Sub)Function Level Allocators (Cont'd)**											
19	**EXTERNALLY DEVELOPED ALLOCATORS**											
20	**ENERGY**											
21	Energy Revenue at pro-forma adjusted level	ENERGY1			1,612,994	1,040,649	259,956	228,750	1,695	81,286	0	658
22	Energy @ Meter (MWh Sales)	ENERGY2			36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
23	**CUSTOMER**											
24	364 & 365 - Cust. Dist. Secondary OH Lines (NCP)	CDISTSOL			7,104,123	4,030,305	1,232,991	1,796,705	0	0	0	44,122
25	366 & 367 - Cust. Dist. Secondary UG Lines (NCP)	CDISTSUL			7,104,123	4,030,305	1,232,991	1,796,705	0	0	0	44,122
26	364 & 366 - Cust. Dist. Secondary Poles, Towers, Fixtures and Conduit (Cust)	CDISTSOLC			1,775,975	1,348,092	210,225	155,655	0	0	0	62,004
27	365 & 367 - Cust. Dist. Secondary Conductors & Devices (Cust)	CDISTSULC			1,775,975	1,348,092	210,225	155,655	0	0	0	62,004
28	369-Services	CSERVICE			4,005,702	2,178,996	339,798	1,457,360	3,492	26,057	0	0
29	370-Meters	CMETERS			391,670	262,153	42,483	66,343	1,518	18,960	214	0
30	371-Installation on Customer Premises	CUSTPREM			1,775,975	1,348,092	210,225	155,655	0	0	0	62,004
31	373-Street Lighting & Signal Systems	CLIGHT			1	0	0	0	0	0	0	1
32	Customer Deposits	CUSTDEP			1	0.328	0.073	0.498	0.003	0.097	0.000	0.000
33	903-Customer Records and Collections	CUSTREC			1.00	0.764	0.120	0.071	0.004	0.036	0.000	0.004
34	905-Miscellaneous Customer Accounts	CUSTCAM			1,729,713	1,348,092	210,225	155,655	373	2,783	39	12,547
35	908-Customer Assistance	CUSTASST			1.00	0.826	0.129	0.042	0.000	0.001	0.000	0.002
36	909-Informational and Instructional Advertising	CUSTADVT			1,729,713	1,348,092	210,225	155,655	373	2,783	39	12,547
37	910-Miscellaneous Customer Service	CUSTCSM			1,729,713	1,348,092	210,225	155,655	373	2,783	39	12,547
38	912/916-Miscellaneous Sales Expense	CUSTSALES			1.00	0.000	0.000	0.362	0.014	0.624	0.000	0.000
39	Number of Bills	CUSTBILLS			20,756,557	16,177,098	2,522,699	1,867,855	4,476	33,396	465	150,568
40	Number of Customers	CUST			1,729,713	1,348,092	210,225	155,655	373	2,783	39	12,547
41	Number of Residential Customers	CUSTRES			1,558,316	1,348,092	210,225	0	0	0	0	0
42	Number of Commercial and Industrial Customers	CUSTCI			158,811	0	0	155,655	373	2,783	0	0
43	Transit Charging - GS	CTCREALLR			0	0	0	0	0	0	0	0
44	Transit Charging - PD/HT	CTCREALLCI			0	0	0	0	0	0	0	0
	Allocation Ratio Tables											
1	**Total-Cost-of-Service Level Allocators**											
2	**INTERNALLY DEVELOPED ALLOCATORS**											
3	**Plant Related**											
4	Intangible Plant	INTPLT			1.00000	0.66633	0.10896	0.16978	0.00389	0.05004	0.00068	0.00031
5	Transmission Plant in Service	TRANPLT			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
6	Distribution Plant in Service	DISTPLT			1.00000	0.52127	0.13303	0.18882	0.00469	0.12921	0.00745	0.01553
7	Distribution plant in Service - R and RH only	DISTPLTRRH			1.00000	0.79669	0.20331	0.00000	0.00000	0.00000	0.00000	0.00000
8	Energy Storage Plant in Service	ENSTORPLT			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
7	General Plant in Service	GENLPLT			1.00000	0.60549	0.12933	0.14399	0.00465	0.10054	0.00533	0.01068
9	Total Electric Plant In Service	TOTPLT			1.00000	0.52271	0.13296	0.18809	0.00469	0.12871	0.00742	0.01544

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
10	Distribution Plant Excl Asset Retirement	DISTPLTXAR			1.00000	0.52401	0.13317	0.18890	0.00464	0.12619	0.00728	0.01581
11	Total Transmission and Distribution Plant	TDPLT			1.00000	0.52127	0.13303	0.18882	0.00469	0.12921	0.00745	0.01553
12	Total Distribution and General Plant	DGPLT			1.00000	0.52263	0.13297	0.18810	0.00469	0.12875	0.00742	0.01545
13	Rate Base	RATEBASE			1.00000	0.53113	0.13426	0.18232	0.00472	0.12713	0.00717	0.01328
14	Account 360	PLT_360			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
15	Account 361	PLT_361			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
16	Account 362	PLT_362			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
17	Account 363	PLT_363			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
18	Account 364	PLT_364			1.00000	0.54838	0.13609	0.17469	0.00520	0.11550	0.00674	0.01341
19	Account 365	PLT_365			1.00000	0.54838	0.13609	0.17469	0.00520	0.11550	0.00674	0.01341
20	Account 366	PLT_366			1.00000	0.52139	0.13197	0.17178	0.00521	0.14881	0.00869	0.01214
21	Account 367	PLT_367			1.00000	0.52139	0.13197	0.17178	0.00521	0.14881	0.00869	0.01214
22	Account 368	PLT_368			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
23	Account 369	PLT_369			1.00000	0.54397	0.08483	0.36382	0.00087	0.00650	0.00000	0.00000
24	Account 370	PLT_370			1.00000	0.66932	0.10847	0.16939	0.00387	0.04841	0.00055	0.00000
25	Account 371	PLT_371			1.00000	0.75907	0.11837	0.08764	0.00000	0.00000	0.00000	0.03491
26	Account 373	PLT_373			1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
27	Distribution Overhead Plant in Service	OHDIST			1.00000	0.54838	0.13609	0.17469	0.00520	0.11550	0.00674	0.01341
28	Distribution Underground Plant in Service	UGDIST			1.00000	0.52139	0.13197	0.17178	0.00521	0.14881	0.00869	0.01214
29	Accounts 360 & 361	PLT_3601			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
30	Accounts 371 & 373	PLT_3713			1.00000	0.14288	0.02228	0.01650	0.00000	0.00000	0.00000	0.81834
31	Distribution Plant Accounts 364-367	DPLT_364-367			1.00000	0.53588	0.13418	0.17335	0.00520	0.13093	0.00764	0.01282
32	**Allocation Ratio Tables** **Total-Cost-of-Service Level Allocators, Cont'd**											
33	**INTERNALLY DEVELOPED ALLOCATORS**											
34	**Production Expense Related**											
35	Account 555	OX_555			1.00000	0.64517	0.16116	0.14182	0.00105	0.05039	0.00000	0.00041
36	O&M Expense Production Other	OX_PROD			1.00000	0.64517	0.16116	0.14182	0.00105	0.05039	0.00000	0.00041
37	Salaries and Wages Production Operation	SALWAGPO			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
					0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
38	**Transmission Expense Related**											
39	Transmission Operation Expense	OX_TRAN			1.00000	0.54791	0.13688	0.19593	0.00273	0.11193	0.00446	0.00015
40	Transmission Maintenance Expense	MX_TRAN			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
41	Transmission Salaries & Wages Accounts 511-567	SALWAGTO			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
42	Transmission Salaries & Wages Accounts 569-574	SALWAGTM			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
43	**Distribution Expense Related**											
44	Account 580	OX_580			1.00000	0.61224	0.12732	0.15555	0.00350	0.08590	0.00470	0.01079
45	Account 581	OX_581			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
46	Account 582	OX_582			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
47	Account 583	OX_583			1.00000	0.54838	0.13609	0.17469	0.00520	0.11550	0.00674	0.01341
48	Account 584	OX_584			1.00000	0.52139	0.13197	0.17178	0.00521	0.14881	0.00869	0.01214
49	Account 585	OX_585			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
50	Account 586	OX_586			1.00000	0.66932	0.10847	0.16939	0.00387	0.04841	0.00055	0.00000
51	Account 587	OX_587			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
52	Account 588	OX_588			1.00000	0.52127	0.13303	0.18882	0.00469	0.12921	0.00745	0.01553
53	Account 589	OX_589			1.00000	0.52127	0.13303	0.18882	0.00469	0.12921	0.00745	0.01553
54	Account 578.2	MX_578.2			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
55	Account 578.3	MX_578.3			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
56	Account 578.4	MX_578.4			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
57	Account 578.5	MX_578.5			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
58	Account 578.6	MX_578.6			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
59	Account 578.7	MX_578.7			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
60	Account 591	MX_591			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
61	Account 592	MX_592			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
62	Account 593	MX_593			1.00000	0.54838	0.13609	0.17469	0.00520	0.11550	0.00674	0.01341
63	Account 594	MX_594			1.00000	0.52139	0.13197	0.17178	0.00521	0.14881	0.00869	0.01214
64	Account 595	MX_595			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
65	Account 596	MX_596			1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
66	Account 597	MX_597			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
67	Account 598	MX_598			1.00000	0.52127	0.13303	0.18882	0.00469	0.12921	0.00745	0.01553
68	O&M Accounts 581-589	OX_DIST			1.00000	0.54893	0.13096	0.17605	0.00444	0.11971	0.00683	0.01309
69	O&M Accounts 591-598	MX_DIST			1.00000	0.52222	0.13374	0.17634	0.00526	0.13643	0.00796	0.01805
	Allocation Ratio Tables											
70	**Total-Cost-of-Service Level Allocators, Cont'd**											
71	**INTERNALLY DEVELOPED ALLOCATORS**											
72	**Customer Distribution Expense Related**											
73	Account 902	OX_902			1.00000	0.66932	0.10847	0.16939	0.00387	0.04841	0.00055	0.00000
74	Account 903	OX_903			1.00000	0.76404	0.12041	0.07120	0.00438	0.03573	0.00019	0.00404
75	Account 904	OX_904			1.00000	0.72536	0.16106	0.10742	0.00021	0.00588	0.00000	0.00007
76	O&M Accounts 902-905	OX_CA			1.00000	0.75107	0.13458	0.08471	0.00276	0.02398	0.00012	0.00278
77	Account908	OX_908			1.00000	0.82571	0.12876	0.04218	0.00010	0.00075	0.00001	0.00248
78	Account909	OX_909			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
79	Account910	OX_910			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
80	O&M Accounts 908-910	OX_CS			1.00000	0.82169	0.12814	0.04634	0.00011	0.00083	0.00001	0.00289
81	Accounts 901-910	X_CACS			1.00000	0.76427	0.13338	0.07754	0.00227	0.01965	0.00010	0.00280
82	Total O&M less Purchased Power	OMXPP			1.00000	0.59567	0.13328	0.15504	0.00390	0.09774	0.00493	0.00944
83	Total O&M less PP less Payroll less Pension	OMXPPPP			1.00000	0.59318	0.13428	0.15785	0.00370	0.09702	0.00483	0.00913
84	**Salaries and Wages Expense Related**											
85	Salaries & Wages Accounts 581-589	SALWAGDO			1.00000	0.61224	0.12732	0.15555	0.00350	0.08590	0.00470	0.01079
86	Salaries & Wages Accounts 591-598	SALWAGDM			1.00000	0.52406	0.13414	0.17660	0.00527	0.13797	0.00805	0.01390
87	Salaries & Wages Accounts 902-905	SALWAGCA			1.00000	0.76445	0.12044	0.07170	0.00427	0.03482	0.00019	0.00412
88	Salaries & Wages Accounts 908-910	SALWAGCS			1.00000	0.82571	0.12876	0.04218	0.00010	0.00075	0.00001	0.00248
89	Salaries & Wages Excluding Admin & Gen	SALWAGXAG			1.00000	0.60492	0.12933	0.14424	0.00466	0.10080	0.00534	0.01070
90	Total Salaries and Wages Expense	SALWAGES			1.00000	0.60549	0.12933	0.14399	0.00465	0.10054	0.00533	0.01068
91	Base Taxable Income	EBT			1.00000	0.56675	0.02528	0.22604	0.00690	0.15097	0.00021	0.02385
92	**REVENUES AND BILLING DETERMINANTS**											
93	Base Rate Sales Revenue	SALESREV			1.00000	0.57283	0.11075	0.17381	0.00498	0.11819	0.00488	0.01456
94	Residential	SREVRES			1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
95	Residential Heating	SREVRH			1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
96	General Service	SREVGS			1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
97	Primary Distribution	SREVPRID			1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
98	High Tension	SREVHT			1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
99	Electric Propulsion	SREVEP			1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
100	Lighting	SREVLCUST			1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
101	Available 1	SREVAV1			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
102	Available 2	SREVAV2			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
103	Available 3	SREVAV3			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
104	Available 4	SREVAV4			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
105	Available 5	SREVAV5			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
106	Available 6	SREVAV6			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
107	Available 7	SREVAV7			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
108	Available 8	SREVAV8			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
109	Available 9	SREVAV9			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Allocation Development and Ratio Tables

Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
110	Available 10	SREVAV10			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
111	R/RH	SREVRRH			1.00000	0.83798	0.16202	0.00000	0.00000	0.00000	0.00000	0.00000
112	GS/PD/HT	SREVGSPDHT			1.00000	0.00000	0.00000	0.58525	0.01676	0.39799	0.00000	0.00000
113	PD/HT	SREVPDHT			1.00000	0.00000	0.00000	0.00000	0.04041	0.95959	0.00000	0.00000
114	Proposed Rate Sales Revenue	PROPREV			1.00000	0.59150	0.14364	0.15968	0.00314	0.09092	0.00387	0.00725
115	Capital Stock	CAPSTOCK			1.00000	0.53955	0.13557	0.18113	0.00431	0.11946	0.00655	0.01344
116	**PRESENT REVENUES/EXPENSES FROM SALES INPUT**											
117	Sales of Electricity Revenues - Distribution				1.00000	0.57283	0.11075	0.17381	0.00498	0.11819	0.00488	0.01456
118	Sales of Electricity Revenues - Transmission				1.00000	0.54791	0.13688	0.19593	0.00273	0.11193	0.00446	0.00015
119	**Allocation of Net Write-Offs, Cust. Advances, and POR**											
120	Net Write-Offs	EXP_904			1.00000	0.72536	0.16106	0.10742	0.00021	0.00588	0.00000	0.00007
121	Customer Advances for Construction	CUSTADV			1.00000	0.53588	0.13418	0.17335	0.00520	0.13093	0.00764	0.01282
122	Customer Advances for Construction - R & RH	CUSTADVRRH			1.00000	0.79975	0.20025	0.00000	0.00000	0.00000	0.00000	0.00000
123	Purchase of Receivables	POR			1.00000	0.23032	0.05694	0.36667	0.00701	0.33627	0.00000	0.00279
124	**Allocation Ratio Tables Total-Cost-of-Service & (Sub)Function Level Allocators**											
125	**EXTERNALLY DEVELOPED ALLOCATORS**											
126	DEMAND - PRODUCTION RELATED											
127	Demand Production	DPROD			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
128	DEMAND - TRANSMISSION RELATED											

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Allocation Development and Ratio Tables

Line No.	Description	Allocator	Allocator Category	Allocator Status	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
129	Demand Transmission (1 Coincident Peak)	DTRAN			1.00000	0.47828	0.06977	0.19173	0.00662	0.24393	0.00899	0.00068
130	Demand Transmission (Revenue)	DTRANR			1.00000	0.54791	0.13688	0.19593	0.00273	0.11193	0.00446	0.00015
131	DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand)											
132	Demand Distribution Primary High Tension	DDISPHT			1.00000	0.41690	0.12754	0.18585	0.00643	0.24445	0.01427	0.00456
133	Demand Distribution Primary High Tension - Residential Only	DDISPHTR			1.00000	0.76574	0.23426	0.00000	0.00000	0.00000	0.00000	0.00000
134	Demand Distribution Primary Overhead Lines	DDISTPOL			1.00000	0.56240	0.17206	0.25072	0.00867	0.00000	0.00000	0.00616
135	Demand Distribution Primary Underground Lines	DDISTPUL			1.00000	0.56240	0.17206	0.25072	0.00867	0.00000	0.00000	0.00616
136	Demand Distribution Secondary Overhead Lines	DDISTSOL			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
137	Demand Distribution Secondary Underground Lines	DDISTSUL			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
138	Demand Distribution Overhead Line Transformers	DDISTSOT			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
139	Demand Distribution Underground Line Transformers	DDISTSUT			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
140	**Allocation Ratio Tables** **Total-Cost-of-Service** **&** **(Sub)Function Level Allocators (Cont'd)**											
141	**EXTERNALLY DEVELOPED ALLOCATORS**											
142	**ENERGY**											
143	Energy Revenue at pro-forma adjusted level	ENERGY1			1.00000	0.64517	0.16116	0.14182	0.00105	0.05039	0.00000	0.00041
144	Energy @ Meter (MWh Sales)	ENERGY2			1.00000	0.31161	0.07703	0.20733	0.00791	0.37955	0.01283	0.00374
145	**CUSTOMER**											
146	364 & 365 - Cust. Dist. Secondary OH Lines (NCP)	CDISTSOL			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
147	366 & 367 - Cust. Dist. Secondary UG Lines (NCP)	CDISTSUL			1.00000	0.56732	0.17356	0.25291	0.00000	0.00000	0.00000	0.00621
148	364 & 366 - Cust. Dist. Secondary Poles, Towers, Fixtures and Conduit (Cust)	CDISTSOLC			1.00000	0.75907	0.11837	0.08764	0.00000	0.00000	0.00000	0.03491
149	365 & 367 - Cust. Dist. Secondary Conductors & Devices (Cust)	CDISTSULC			1.00000	0.75907	0.11837	0.08764	0.00000	0.00000	0.00000	0.03491
150	369-Services	CSERVICE			1.00000	0.54397	0.08483	0.36382	0.00087	0.00650	0.00000	0.00000
151	370-Meters	CMETERS			1.00000	0.66932	0.10847	0.16939	0.00387	0.04841	0.00055	0.00000
152	371-Installation on Customer Premises	CUSTPREM			1.00000	0.75907	0.11837	0.08764	0.00000	0.00000	0.00000	0.03491
153	373-Street Lighting & Signal Systems	CLIGHT			1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
154	Customer Deposits	CUSTDEP			1.00000	0.32837	0.07291	0.49781	0.00348	0.09744	0.00000	0.00000
155	903-Customer Records and Collections	CUSTREC			1.00000	0.76404	0.12041	0.07120	0.00438	0.03573	0.00019	0.00404
156	905-Miscellaneous Customer Accounts	CUSTCAM			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
157	908-Customer Assistance	CUSTASST			1.00000	0.82571	0.12876	0.04218	0.00010	0.00075	0.00001	0.00248
158	909-Informational and Instructional Advertising	CUSTADVT			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
159	910-Miscellaneous Customer Service	CUSTCSM			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
160	912/916-Miscellaneous Sales Expense	CUSTSALES			1.00000	0.00000	0.00000	0.36193	0.01358	0.62449	0.00000	0.00000
161	Number of Bills	CUSTBILLS			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
162	Number of Customers	CUST			1.00000	0.77937	0.12154	0.08999	0.00022	0.00161	0.00002	0.00725
163	Number of Residential Customers	CUSTRES			1.00000	0.86509	0.13491	0.00000	0.00000	0.00000	0.00000	0.00000
164	Number of Commercial and Industrial Customers	CUSTCI			1.00000	0.00000	0.00000	0.98013	0.00235	0.01752	0.00000	0.00000
165	Transit Charging - GS	CTCREALLR			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
166	Transit Charging - PD/HT	CTCREALLCI			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

PECO Exhibit JD-3:
Revenue Requirement by Functional Classification

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
S	1	**SUMMARY OF RETURN AT PRESENT RATES**												
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**												
S	3	OPERATING REVENUE												
S	4	Sales of Electricity - Base			1,980,591	1,239,750	9,570	731,270	0	1,569	1,238,182	875,411	260,177	0
S	5	Decommissioning Revenues			(4,213)	0	(4,213)	0	0	0	0	0	0	0
S	6	Other Operating Revenue			58,150	36,109	81	21,960	0	15	36,094	24,650	7,366	0
S	7	TOTAL OPERATING REVENUE			2,034,528	1,275,859	5,439	753,230	0	1,583	1,274,276	900,061	267,543	0
S														
S	8	OPERATING EXPENSES												
S	9	Operation and Maintenance Expense			860,811	454,752	3,796	402,263	0	575	454,177	323,464	111,717	0
S	10	Depreciation and Amortization Expense			424,593	277,779	0	146,814	0	0	277,779	199,627	47,863	0
S	11	Taxes Other Than Income Taxes-General			30,519	20,091	899	9,530	0	134	19,956	16,266	2,865	0
S	12	Taxes Other Than Income Taxes-Distribution GRT			114,483	71,801	554	42,128	0	91	71,711	50,785	15,008	0
S	13	Income Taxes			16,736	12,901	33	3,802	0	137	12,764	8,246	3,524	0
S	14	TOTAL OPERATING EXPENSES			1,447,142	837,324	5,282	604,537	0	937	836,387	598,388	180,978	0
S	15	**OPERATING INCOME (RETURN)**			587,385	438,535	157	148,693	0	647	437,889	301,673	86,565	0
S														
S	16	**DEVELOPMENT OF RATE BASE**												
S	17	Electric Plant in Service			13,154,586	9,755,413	0	3,399,173	0	0	9,755,413	6,820,173	1,786,912	0
S	18	Less: Accumulated Depreciation			2,223,678	1,446,011	0	777,667	0	0	1,446,011	1,145,757	148,208	0
S	19	Plus: Rate Base Additions			1,072,510	591,630	2,900	477,980	0	11,987	579,643	425,516	130,191	0
S	20	Less: Rate Base Deductions			1,155,663	785,632	0	370,031	0	0	785,632	550,738	146,906	0
S	21	**TOTAL DISTRIBUTION RATE BASE**			10,847,754	8,115,400	2,900	2,729,454	0	11,987	8,103,413	5,549,195	1,621,988	0
S														
S	22	**DISTRIBUTION RATE OF RETURN (PRESENT)**			5.41%	5.40%	5.41%	5.45%	0.00%	5.39%	5.40%	5.44%	5.34%	0.00%
S	23	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**			1.00	1.00	1.00	1.00	0.00	1.00	1.00	1.00	1.00	0.00
S														
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**												
S	25	Purchased Electric Revenues			1,612,994	0	1,612,994	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense			1,513,792	0	1,513,792	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense			95,167	0	95,167	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes			531	0	531	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income			3,505	0	3,505	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital			91,220	0	91,220	0	0	0	0	0	0	0
S	31	**PURCHASED POWER RATE OF RETURN (PRESENT)**			3.84%	0.00%	3.84%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S														
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**												
S	33	Transmission Revenues			241,020	241,020	0	0	0	241,020	0	0	0	0
S	34	Transmission O&M Expense			225,704	225,704	0	0	0	225,704	0	0	0	0
S	35	Transmission GRT Expense			14,220	14,220	0	0	0	14,220	0	0	0	0
S	36	Transmission Income Taxes			215	215	0	0	0	215	0	0	0	0
S	37	Transmission Operating Income			880	880	0	0	0	880	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital			12,703	12,703	0	0	0	12,703	0	0	0	0
S	39	**TRANSMISSION RATE OF RETURN (PRESENT)**			6.93%	6.93%	0.00%	0.00%	0.00%	6.93%	0.00%	0.00%	0.00%	0.00%
S														
S	40	**TOTAL OPERATING INCOME (RETURN)**			591,770	439,415	3,662	148,693	0	1,527	437,889	301,673	86,565	0
S	41	**TOTAL RATE BASE**			10,951,677	8,128,103	94,119	2,729,454	0	24,690	8,103,413	5,549,195	1,621,988	0
S	42	**COMPOSITE RATE OF RETURN AT CURRENT RATES**			5.40%	5.41%	3.89%	5.45%	0.00%	6.18%	5.40%	5.44%	5.34%	0.00%
S														
S														
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**												
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**												
S	45	**RATE BASE**			10,847,754	8,115,400	2,900	2,729,454	0	11,987	8,103,413	5,549,195	1,621,988	0
S	46	**RETURN (= RATE BASE * 8.08% ROR)**			876,500	655,725	234	220,540	0	969	654,757	448,375	131,057	0
S	47	**PLUS:**												
S	48	**OPERATING EXPENSES**												
S	49	Operation and Maintenance Expense			867,155	459,457	3,881	403,818	0	585	458,871	326,639	112,680	0
S	50	Depreciation and Amortization Expense			424,593	277,779	0	146,814	0	0	277,779	199,627	47,863	0
S	51	Taxes Other Than Income Taxes-General			30,519	20,091	899	9,530	0	134	19,956	16,266	2,865	0
S	52	Taxes Other Than Income Taxes-Distribution GRT			139,458	90,560	565	48,333	0	119	90,441	63,456	18,850	0
S	53	State and Federal Income Taxes			121,092	91,296	60	29,736	0	253	91,043	61,199	19,584	0
S	54	**TOTAL OPERATING EXPENSES**			1,582,817	939,182	5,404	638,231	0	1,091	938,091	667,187	201,843	0
S														
S	55	**EQUALS TOTAL COST OF SERVICE**			2,459,317	1,594,907	5,639	858,771	0	2,060	1,592,848	1,115,563	332,900	0
S	56	**LESS:**												
S	57	Decommissioning Revenues			(4,213)	0	(4,213)	0	0	0	0	0	0	0
S	58	Other Operating Revenue			59,635	37,210	101	22,324	0	17	37,193	25,393	7,592	0

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
S	1	**SUMMARY OF RETURN AT PRESENT RATES**											
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**											
S	3	OPERATING REVENUE											
S	4	Sales of Electricity - Base			102,594	9,570	0	326,225	29,379	87,577	212,814	47,491	27,786
S	5	Decommissioning Revenues			0	(4,213)	0	0	0	0	0	0	0
S	6	Other Operating Revenue			4,078	81	0	9,615	1,641	2,022	2,486	555	5,641
S	7	TOTAL OPERATING REVENUE			106,671	5,439	0	335,839	31,020	89,599	215,299	48,046	33,426
S													
S	8	OPERATING EXPENSES											
S	9	Operation and Maintenance Expense			18,996	3,796	0	135,461	6,165	18,010	172,066	43,686	26,875
S	10	Depreciation and Amortization Expense			30,289	0	0	60,676	9,662	60,143	11,978	507	3,849
S	11	Taxes Other Than Income Taxes-General			825	899	0	3,553	319	583	4,097	195	781
S	12	Taxes Other Than Income Taxes-Distribution GRT			5,918	554	0	18,789	1,697	5,051	12,253	2,731	1,607
S	13	Income Taxes			993	33	0	5,007	(1,152)	(1,854)	2,221	145	(564)
S	14	TOTAL OPERATING EXPENSES			57,021	5,282	0	223,486	16,692	81,933	202,615	47,264	32,547
S	15	**OPERATING INCOME (RETURN)**			49,651	157	0	112,353	14,328	7,666	12,685	783	879
S													
S	16	**DEVELOPMENT OF RATE BASE**											
S	17	Electric Plant in Service			1,148,328	0	0	2,299,474	517,556	424,721	55,775	2,360	99,288
S	18	Less: Accumulated Depreciation			152,046	0	0	194,723	227,594	276,568	23,476	993	54,313
S	19	Plus: Rate Base Additions			23,936	2,900	0	155,182	7,267	26,925	232,060	14,510	42,035
S	20	Less: Rate Base Deductions			87,988	0	0	188,376	39,420	34,098	28,218	1,194	78,726
S	21	**TOTAL DISTRIBUTION RATE BASE**			932,230	2,900	0	2,071,557	257,809	140,980	236,141	14,683	8,283
S													
S	22	**DISTRIBUTION RATE OF RETURN (PRESENT)**			5.33%	5.41%	0.00%	5.42%	5.56%	5.44%	5.37%	5.33%	10.61%
S	23	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**			1.00	1.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00
S													
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**											
S	25	Purchased Electric Revenues			0	1,612,994	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense			0	1,513,792	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense			0	95,167	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes			0	531	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income			0	3,505	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital			0	91,220	0	0	0	0	0	0	0
S	31	**PURCHASED POWER RATE OF RETURN (PRESENT)**			0.00%	3.84%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S													
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**											
S	33	Transmission Revenues			0	0	0	0	0	0	0	0	0
S	34	Transmission O&M Expense			0	0	0	0	0	0	0	0	0
S	35	Transmission GRT Expense			0	0	0	0	0	0	0	0	0
S	36	Transmission Income Taxes			0	0	0	0	0	0	0	0	0
S	37	Transmission Operating Income			0	0	0	0	0	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital			0	0	0	0	0	0	0	0	0
S	39	**TRANSMISSION RATE OF RETURN (PRESENT)**			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S													
S	40	**TOTAL OPERATING INCOME (RETURN)**			49,651	3,662	0	112,353	14,328	7,666	12,685	783	879
S	41	**TOTAL RATE BASE**			932,230	94,119	0	2,071,557	257,809	140,980	236,141	14,683	8,283
S	42	**COMPOSITE RATE OF RETURN AT CURRENT RATES**			5.33%	3.89%	0.00%	5.42%	5.56%	5.44%	5.37%	5.33%	10.61%
S													
S													
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**											
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**											
S	45	**RATE BASE**			932,230	2,900	0	2,071,557	257,809	140,980	236,141	14,683	8,283
S	46	**RETURN (= RATE BASE * 8.08% ROR)**			75,324	234	0	167,382	20,831	11,391	19,080	1,186	669
S	47	**PLUS:**											
S	48	**OPERATING EXPENSES**											
S	49	Operation and Maintenance Expense			19,552	3,881	0	136,652	6,306	18,090	172,205	43,694	26,870
S	50	Depreciation and Amortization Expense			30,289	0	0	60,676	9,662	60,143	11,978	507	3,849
S	51	Taxes Other Than Income Taxes-General			825	899	0	3,553	319	583	4,097	195	781
S	52	Taxes Other Than Income Taxes-Distribution GRT			8,135	565	0	23,542	2,259	5,372	12,805	2,766	1,588
S	53	State and Federal Income Taxes			10,260	60	0	24,870	1,196	(510)	4,529	291	(640)
S	54	**TOTAL OPERATING EXPENSES**			69,061	5,404	0	249,293	19,742	83,680	205,614	47,453	32,449
S													
S	55	**EQUALS TOTAL COST OF SERVICE**			144,385	5,639	0	416,675	40,573	95,071	224,694	48,639	33,118
S	56	**LESS:**											
S	57	Decommissioning Revenues			0	(4,213)	0	0	0	0	0	0	0
S	58	Other Operating Revenue			4,208	101	0	9,894	1,674	2,040	2,518	557	5,640

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Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
S	59	**EQUALS:**												
S	60	**DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR**			2,403,895	1,557,697	9,750	836,447	0	2,043	1,555,655	1,090,169	325,308	0
S	61	Distribution Cost Increase without Forfeited Discount			423,300	317,947	177	105,177	0	474	317,473	214,758	65,131	0
S	62	**TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE**			424,789	319,049	200	105,541	(0)	476	318,572	215,502	65,357	(0)
S	63	**REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUNT(%**			21.37%	25.65%	1.85%	14.38%	0.00%	30.21%	25.64%	24.53%	25.03%	0.00%
S					8.08%	8.08%	8.08%	8.08%	0.00%	8.08%	8.08%	8.08%	8.08%	0.00%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**												
S	65	**RATE BASE (CWC)**			91,220	0	91,220	0	0	0	0	0	0	0
S	66	**RETURN (= RATE BASE * 8.08% ROR)**			7,371	0	7,371	0	0	0	0	0	0	0
S	67	**PLUS:**												
S	68	**OPERATING EXPENSES**												
S	69	Purchased Power O&M Expense			1,513,792	0	1,513,792	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes			1,926	0	1,926	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense			95,497	0	95,497	0	0	0	0	0	0	0
S	72	**EQUALS TOTAL PURCHASED POWER COST OF SERVICE**			1,618,585	0	1,618,585	0	0	0	0	0	0	0
S	73	**TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE**			5,591	0	5,591	0	0	0	0	0	0	0
S	74	**REVENUE INCREASE TO DISTRIBUTION REVENUES (%)**			0.35%	0.00%	0.35%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S					8.08%	0.00%	8.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**												
S	76	**RATE BASE (CWC)**			12,703	12,703	0	0	0	12,703	0	0	0	0
S	77	**RETURN (= RATE BASE * 8.08% ROR)**			1,026	1,026	0	0	0	1,026	0	0	0	0
S	78	**PLUS:**												
S	79	**OPERATING EXPENSES**												
S	80	Transmission O&M Expense			225,704	225,704	0	0	0	225,704	0	0	0	0
S	81	Transmission Income Taxes			268	268	0	0	0	268	0	0	0	0
S	82	Transmission GRT Expense			14,233	14,233	0	0	0	14,233	0	0	0	0
S	83	**EQUALS TOTAL TRANSMISSION COST OF SERVICE**			241,232	241,232	0	0	0	241,232	0	0	0	0
S	84	**TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE**			212	212	0	0	0	212	0	0	0	0
S	85	**REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)**			0.09%	0.09%	0.00%	0.00%	0.00%	0.09%	0.00%	0.00%	0.00%	0.00%
S					8.08%	8.08%	0.00%	0.00%	0.00%	8.08%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**			430,592	319,260	5,791	105,541	(0)	688	318,572	215,502	65,357	(0)
S														
S														
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**												
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**												
S	89	**RATE BASE**			10,951,677	8,128,103	94,119	2,729,454	0	24,690	8,103,413	5,549,195	1,621,988	0
S	90	**RETURN (= RATE BASE * 8.08% ROR)**			884,897	656,752	7,605	220,540	0	1,995	654,757	448,375	131,057	0
S	91	**PLUS:**												
S	92	**OPERATING EXPENSES**												
S	93	Operation and Maintenance Expense			2,606,652	685,161	1,517,673	403,818	0	226,290	458,871	326,639	112,680	0
S	94	Depreciation and Amortization Expense			424,593	277,779	0	146,814	0	0	277,779	199,627	47,863	0
S	95	Taxes Other Than Income Taxes-General			30,519	20,091	899	9,530	0	134	19,956	16,266	2,865	0
S	96	Taxes Other Than Income Taxes-GRT			249,187	104,793	96,061	48,333	0	14,351	90,441	63,456	18,850	0
S	97	State and Federal Income Taxes			123,286	91,564	1,986	29,736	0	521	91,043	61,199	19,584	0
S	98	**TOTAL OPERATING EXPENSES**			3,434,237	1,179,388	1,616,619	638,231	0	241,297	938,091	667,187	201,843	0
S														
S	99	**EQUALS TOTAL COST OF SERVICE**			4,319,134	1,836,139	1,624,224	858,771	0	243,292	1,592,848	1,115,563	332,900	0
S	100	**LESS:**												
S	101	Decommissioning Revenues			(4,213)	0	(4,213)	0	0	0	0	0	0	0
S	102	Other Operating Revenue			59,635	37,210	101	22,324	0	17	37,193	25,393	7,592	0
S	103	**EQUALS:**												
S	104	**OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR**			4,263,712	1,798,929	1,628,336	836,447	0	243,274	1,555,655	1,090,169	325,308	0
S	105	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUNT**			429,106	318,158	5,771	105,177	(0)	686	317,473	214,758	65,131	(0)
S	106	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**			430,592	319,260	5,791	105,541	(0)	688	318,572	215,502	65,357	(0)
S					8.08%	8.08%	8.08%	8.08%	0.00%	8.08%	8.08%	8.08%	8.08%	0.00%
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PECO Energy Company
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Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
S	59	**EQUALS:**											
S	60	**DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR**			140,177	9,750	0	406,782	38,899	93,030	222,176	48,082	27,478
S	61	Distribution Cost Increase without Forfeited Discount			37,584	177	0	80,557	9,520	5,453	9,363	591	(307)
S	62	**TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE**			37,714	200	(0)	80,836	9,553	5,472	9,395	593	(308)
S	63	**REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUNT(%**			36.63%	1.85%	0.00%	24.69%	32.40%	6.23%	4.40%	1.24%	-1.11%
S					8.08%	8.08%	0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**											
S	65	**RATE BASE (CWC)**			0	91,220	0	0	0	0	0	0	0
S	66	**RETURN (= RATE BASE * 8.08% ROR)**			0	7,371	0	0	0	0	0	0	0
S	67	**PLUS:**											
S	68	**OPERATING EXPENSES**											
S	69	Purchased Power O&M Expense			0	1,513,792	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes			0	1,926	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense			0	95,497	0	0	0	0	0	0	0
S	72	**EQUALS TOTAL PURCHASED POWER COST OF SERVICE**			0	1,618,585	0	0	0	0	0	0	0
S	73	**TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE**			0	5,591	0	0	0	0	0	0	0
S	74	**REVENUE INCREASE TO DISTRIBUTION REVENUES (%)**			0.00%	0.35%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S					0.00%	8.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**											
S	76	**RATE BASE (CWC)**			0	0	0	0	0	0	0	0	0
S	77	**RETURN (= RATE BASE * 8.08% ROR)**			0	0	0	0	0	0	0	0	0
S	78	**PLUS:**											
S	79	**OPERATING EXPENSES**											
S	80	Transmission O&M Expense			0	0	0	0	0	0	0	0	0
S	81	Transmission Income Taxes			0	0	0	0	0	0	0	0	0
S	82	Transmission GRT Expense			0	0	0	0	0	0	0	0	0
S	83	**EQUALS TOTAL TRANSMISSION COST OF SERVICE**			0	0	0	0	0	0	0	0	0
S	84	**TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE**			0	0	0	0	0	0	0	0	0
S	85	**REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)**			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**			37,714	5,791	(0)	80,836	9,553	5,472	9,395	593	(308)
S													
S													
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**											
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**											
S	89	**RATE BASE**			932,230	94,119	0	2,071,557	257,809	140,980	236,141	14,683	8,283
S	90	**RETURN (= RATE BASE * 8.08% ROR)**			75,324	7,605	0	167,382	20,831	11,391	19,080	1,186	669
S	91	**PLUS:**											
S	92	**OPERATING EXPENSES**											
S	93	Operation and Maintenance Expense			19,552	1,517,673	0	136,652	6,306	18,090	172,205	43,694	26,870
S	94	Depreciation and Amortization Expense			30,289	0	0	60,676	9,662	60,143	11,978	507	3,849
S	95	Taxes Other Than Income Taxes-General			825	899	0	3,553	319	583	4,097	195	781
S	96	Taxes Other Than Income Taxes-GRT			8,135	96,061	0	23,542	2,259	5,372	12,805	2,766	1,588
S	97	State and Federal Income Taxes			10,260	1,986	0	24,870	1,196	(510)	4,529	291	(640)
S	98	**TOTAL OPERATING EXPENSES**			69,061	1,616,619	0	249,293	19,742	83,680	205,614	47,453	32,449
S													
S	99	**EQUALS TOTAL COST OF SERVICE**			144,385	1,624,224	0	416,675	40,573	95,071	224,694	48,639	33,118
S	100	**LESS:**											
S	101	Decommissioning Revenues			0	(4,213)	0	0	0	0	0	0	0
S	102	Other Operating Revenue			4,208	101	0	9,894	1,674	2,040	2,518	557	5,640
S	103	**EQUALS:**											
S	104	**OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR**			140,177	1,628,336	0	406,782	38,899	93,030	222,176	48,082	27,478
S	105	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUNT**			37,584	5,771	(0)	80,557	9,520	5,453	9,363	591	(307)
S	106	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**			37,714	5,791	(0)	80,836	9,553	5,472	9,395	593	(308)
S					8.08%	8.08%	0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
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Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
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RBP	1	**DEVELOPMENT OF RATE BASE**												
RBP	2	**ELECTRIC PLANT IN SERVICE**												
RBP	3	INTANGIBLE PLANT												
RBP	4	302-303-Franchise and consents & Misc Intang. Plant	TDPLT	INTERNAL	142	106	0	36	0	0	106	74	19	0
RBP	5	303-AMI Plant	CMETERS	EXTERNAL	6,914	0	0	6,914	0	0	0	0	0	0
RBP	6	TOTAL INTANGIBLE PLANT			7,056	106	0	6,950	0	0	106	74	19	0
RBP														
RBP	7	TRANSMISSION PLANT												
RBP	8	350-359 Accounts	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	9	361- Transmission Related Plant	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	10	TOTAL TRANSMISSION PLANT			0	0	0	0	0	0	0	0	0	0
RBP														
RBP	11	DISTRIBUTION PLANT												
RBP	12	360-Land & Land Rights	DDISPHT	EXTERNAL	56,497	56,497	0	0	0	0	56,497	56,497	0	0
RBP	13	361-Structures & Improvements	DDISPHT	EXTERNAL	319,617	319,617	0	0	0	0	319,617	319,617	0	0
RBP	14	362-Station Equipment	DDISPHT	EXTERNAL	1,387,485	1,387,485	0	0	0	0	1,387,485	1,387,485	0	0
RBP	15	363-Computer HW SW and Equipment												
RBP	16	363.1 Computer Hardware	DDISPHT	EXTERNAL	11,877	11,877	0	0	0	0	11,877	11,877	0	0
RBP	17	363.2 Computer Software	DDISPHT	EXTERNAL	181,334	181,334	0	0	0	0	181,334	181,334	0	0
RBP	18	363.3 Communication Equipment	DDISPHT	EXTERNAL	137,623	137,623	0	0	0	0	137,623	137,623	0	0
RBP	19	Total Account 363			330,833	330,833	0	0	0	0	330,833	330,833	0	0
RBP	20	364-Poles,Towers & Fixtures												
RBP	21	Primary HT	DDISPHT	EXTERNAL	909,779	909,779	0	0	0	0	909,779	909,779	0	0
RBP	22	Primary	DDISTPOL	EXTERNAL	479,969	479,969	0	0	0	0	479,969	0	479,969	0
RBP	23	Secondary	CDISTSOLC	EXTERNAL	535,797	0	0	535,797	0	0	0	0	0	0
RBP	24	Total Account 364			1,925,544	1,389,747	0	535,797	0	0	1,389,747	909,779	479,969	0
RBP	25	365-Overhead Conductors & Devices												
RBP	26	Primary HT	DDISPHT	EXTERNAL	1,290,018	1,290,018	0	0	0	0	1,290,018	1,290,018	0	0
RBP	27	Primary	DDISTPOL	EXTERNAL	680,570	680,570	0	0	0	0	680,570	0	680,570	0
RBP	28	Secondary	CDISTSULC	EXTERNAL	759,731	0	0	759,731	0	0	0	0	0	0
RBP	29	Total Account 365			2,730,320	1,970,588	0	759,731	0	0	1,970,588	1,290,018	680,570	0
RBP	30	366-Underground Conduit												
RBP	31	Primary HT	DDISPHT	EXTERNAL	829,340	829,340	0	0	0	0	829,340	829,340	0	0
RBP	32	Primary	DDISTPUL	EXTERNAL	203,444	203,444	0	0	0	0	203,444	0	203,444	0
RBP	33	Secondary	CDISTSOLC	EXTERNAL	329,526	0	0	329,526	0	0	0	0	0	0
RBP	34	Total Account 366			1,362,310	1,032,785	0	329,526	0	0	1,032,785	829,340	203,444	0
RBP	35	367-Underground Conductors & Devices												
RBP	36	Primary HT	DDISPHT	EXTERNAL	1,616,189	1,616,189	0	0	0	0	1,616,189	1,616,189	0	0
RBP	37	Primary	DDISTPUL	EXTERNAL	396,465	396,465	0	0	0	0	396,465	0	396,465	0
RBP	38	Secondary	CDISTSULC	EXTERNAL	642,168	0	0	642,168	0	0	0	0	0	0
RBP	39	Total Account 367			2,654,822	2,012,655	0	642,168	0	0	2,012,655	1,616,189	396,465	0
RBP	40	368-Line Transformers	DDISTSUT	EXTERNAL	1,145,141	1,145,141	0	0	0	0	1,145,141	0	0	0
RBP	41	369-Services	CSERVICE	EXTERNAL	516,670	0	0	516,670	0	0	0	0	0	0
RBP	42	370-Meters	CMETERS	EXTERNAL	413,020	0	0	413,020	0	0	0	0	0	0
RBP	43	371-Installation on Customer Premises	CUSTPREM	EXTERNAL	16,772	0	0	16,772	0	0	0	0	0	0
RBP	44	373-Street Lighting & Signal Systems	CLIGHT	EXTERNAL	72,331	0	0	72,331	0	0	0	0	0	0
RBP	45	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	INTERNAL	4,017	2,970	0	1,048	0	0	2,970	2,043	561	0
RBP	46	SUBTOTAL DISTRIBUTION PLANT			12,935,381	9,648,318	0	3,287,064	0	0	9,648,318	6,741,801	1,761,010	0
RBP														

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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
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RBP	1	**DEVELOPMENT OF RATE BASE**											
RBP	2	**ELECTRIC PLANT IN SERVICE**											
RBP	3	INTANGIBLE PLANT											
RBP	4	302-303-Franchise and consents & Misc Intang. Plant	TDPLT	INTERNAL	13	0	0	25	6	5	0	0	1
RBP	5	303-AMI Plant	CMETERS	EXTERNAL	0	0	0	0	0	6,914	0	0	0
RBP	6	TOTAL INTANGIBLE PLANT			13	0	0	25	6	6,918	0	0	1
RBP													
RBP	7	TRANSMISSION PLANT											
RBP	8	350-359 Accounts	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	9	361- Transmission Related Plant	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	10	TOTAL TRANSMISSION PLANT			0	0	0	0	0	0	0	0	0
RBP													
RBP	11	DISTRIBUTION PLANT											
RBP	12	360-Land & Land Rights	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	13	361-Structures & Improvements	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	14	362-Station Equipment	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	15	363-Computer HW SW and Equipment											
RBP	16	363.1 Computer Hardware	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	17	363.2 Computer Software	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	18	363.3 Communication Equipment	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	19	Total Account 363			0	0	0	0	0	0	0	0	0
RBP	20	364-Poles,Towers & Fixtures											
RBP	21	Primary HT	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	22	Primary	DDISTPOL	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	23	Secondary	CDISTSOLC	EXTERNAL	0	0	0	535,797	0	0	0	0	0
RBP	24	Total Account 364			0	0	0	535,797	0	0	0	0	0
RBP	25	365-Overhead Conductors & Devices											
RBP	26	Primary HT	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	27	Primary	DDISTPOL	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	28	Secondary	CDISTSULC	EXTERNAL	0	0	0	759,731	0	0	0	0	0
RBP	29	Total Account 365			0	0	0	759,731	0	0	0	0	0
RBP	30	366-Underground Conduit											
RBP	31	Primary HT	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	32	Primary	DDISTPUL	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	33	Secondary	CDISTSOLC	EXTERNAL	0	0	0	329,526	0	0	0	0	0
RBP	34	Total Account 366			0	0	0	329,526	0	0	0	0	0
RBP	35	367-Underground Conductors & Devices											
RBP	36	Primary HT	DDISPHT	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	37	Primary	DDISTPUL	EXTERNAL	0	0	0	0	0	0	0	0	0
RBP	38	Secondary	CDISTSULC	EXTERNAL	0	0	0	642,168	0	0	0	0	0
RBP	39	Total Account 367			0	0	0	642,168	0	0	0	0	0
RBP	40	368-Line Transformers	DDISTSUT	EXTERNAL	1,145,141	0	0	0	0	0	0	0	0
RBP	41	369-Services	CSERVICE	EXTERNAL	0	0	0	0	516,670	0	0	0	0
RBP	42	370-Meters	CMETERS	EXTERNAL	0	0	0	0	0	413,020	0	0	0
RBP	43	371-Installation on Customer Premises	CUSTPREM	EXTERNAL	0	0	0	0	0	0	0	0	16,772
RBP	44	373-Street Lighting & Signal Systems	CLIGHT	EXTERNAL	0	0	0	0	0	0	0	0	72,331
RBP	45	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	INTERNAL	365	0	0	723	165	132	0	0	28
RBP	46	SUBTOTAL DISTRIBUTION PLANT			1,145,506	0	0	2,267,945	516,835	413,152	0	0	89,132
RBP													

PECO Energy Company
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Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
RBP	47	ENERGY STORAGE PLANT												
RBP	48	387 [Reserved]	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT			0	0	0	0	0	0	0	0	0	0
RBP														
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)			12,935,381	9,648,318	0	3,287,064	0	0	9,648,318	6,741,801	1,761,010	0
RBP														
RBP														
RBP														
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**												
RBP														
RBP	64	GENERAL PLANT												
RBP	65	389-Land and Land Rights	SALWAGES	INTERNAL	930	469	0	461	0	0	469	343	113	0
RBP	66	390-Structures and Improvements	SALWAGES	INTERNAL	65,382	32,973	0	32,409	0	0	32,973	24,131	7,977	0
RBP	67	391-Office Furniture & Equipment	SALWAGES	INTERNAL	8,231	4,151	0	4,080	0	0	4,151	3,038	1,004	0
RBP	68	393-Store Equipment	SALWAGES	INTERNAL	38	19	0	19	0	0	19	14	5	0
RBP	69	394-Tools, Shop & Garage Equip.	SALWAGES	INTERNAL	64,233	32,394	0	31,840	0	0	32,394	23,707	7,836	0
RBP	70	395-Laboratory Equipment	SALWAGES	INTERNAL	85	43	0	42	0	0	43	31	10	0
RBP	71	397 Communication Equipment												
RBP	72	397.1 Computer Hardware	SALWAGES	INTERNAL	6,872	3,466	0	3,406	0	0	3,466	2,536	838	0
RBP	73	397.2 Computer Software	SALWAGES	INTERNAL	23,829	12,017	0	11,812	0	0	12,017	8,794	2,907	0
RBP	74	397.3 Communication Equipment	SALWAGES	INTERNAL	38,899	19,617	0	19,282	0	0	19,617	14,357	4,746	0
RBP	75	Total Account 397			69,600	35,100	0	34,500	0	0	35,100	25,687	8,491	0
RBP	76	398-Miscellaneous Equipment / ARO	SALWAGES	INTERNAL	1,750	883	0	868	0	0	883	646	214	0
RBP	77	399-Other Tangible Property	SALWAGES	INTERNAL	1,898	957	0	941	0	0	957	701	232	0
RBP	78	TOTAL GENERAL PLANT			212,149	106,989	0	105,160	0	0	106,989	78,298	25,882	0
RBP														
RBP														
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**			13,154,586	9,755,413	0	3,399,173	0	0	9,755,413	6,820,173	1,786,912	0
RBP														
RBP														
RBP													

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Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
RBP	47	ENERGY STORAGE PLANT											
RBP	48	387 [Reserved]	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT			0	0	0	0	0	0	0	0	0
RBP													
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)			1,145,506	0	0	2,267,945	516,835	413,152	0	0	89,132
RBP													
RBP													
RBP													
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**											
RBP													
RBP	64	GENERAL PLANT											
RBP	65	389-Land and Land Rights	SALWAGES	INTERNAL	12	0	0	138	3	20	245	10	45
RBP	66	390-Structures and Improvements	SALWAGES	INTERNAL	866	0	0	9,709	221	1,433	17,189	727	3,130
RBP	67	391-Office Furniture & Equipment	SALWAGES	INTERNAL	109	0	0	1,222	28	180	2,164	92	394
RBP	68	393-Store Equipment	SALWAGES	INTERNAL	1	0	0	6	0	1	10	0	2
RBP	69	394-Tools, Shop & Garage Equip.	SALWAGES	INTERNAL	851	0	0	9,539	217	1,408	16,887	714	3,075
RBP	70	395-Laboratory Equipment	SALWAGES	INTERNAL	1	0	0	13	0	2	22	1	4
RBP	71	397 Communication Equipment											
RBP	72	397.1 Computer Hardware	SALWAGES	INTERNAL	91	0	0	1,020	23	151	1,807	76	329
RBP	73	397.2 Computer Software	SALWAGES	INTERNAL	316	0	0	3,539	80	522	6,265	265	1,141
RBP	74	397.3 Communication Equipment	SALWAGES	INTERNAL	515	0	0	5,777	131	853	10,227	433	1,862
RBP	75	Total Account 397			922	0	0	10,336	235	1,526	18,298	774	3,331
RBP	76	398-Miscellaneous Equipment / ARO	SALWAGES	INTERNAL	23	0	0	260	6	38	460	19	84
RBP	77	399-Other Tangible Property	SALWAGES	INTERNAL	25	0	0	282	6	42	499	21	91
RBP	78	TOTAL GENERAL PLANT			2,809	0	0	31,505	716	4,651	55,775	2,360	10,155
RBP													
RBP													
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**			1,148,328	0	0	2,299,474	517,556	424,721	55,775	2,360	99,288
RBP													
RBP													
RBP												

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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
RBP														
RBP														
RBP														
RBP														
RBP														
RBP														
RBP														
RBD	1	**LESS: ACCUMULATED DEPRECIATION**												
RBD														
RBD	2	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	INTPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBD														
RBD	3	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	TRANPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBD														
RBD	4	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION												
RBD	5	360-Land & Land Rights	PLT_360	INTERNAL	310	310	0	0	0	0	310	310	0	0
RBD	6	361-Structures & Improvements	PLT_361	INTERNAL	57,133	57,133	0	0	0	0	57,133	57,133	0	0
RBD	7	362-Station Equipment	PLT_362	INTERNAL	492,797	492,797	0	0	0	0	492,797	492,797	0	0
RBD	8	363-Computer HW SW and Equipment	PLT_363	INTERNAL	179,828	179,828	0	0	0	0	179,828	179,828	0	0
RBD	9	364-Poles,Towers & Fixtures	PLT_364	INTERNAL	(2,932)	(2,116)	0	(816)	0	0	(2,116)	(1,385)	(731)	0
RBD	10	365-Overhead Conductors & Devices	PLT_365	INTERNAL	328,256	236,917	0	91,340	0	0	236,917	155,094	81,823	0
RBD	11	366-Underground Conduit	PLT_366	INTERNAL	225,322	170,819	0	54,502	0	0	170,819	137,170	33,649	0
RBD	12	367-Underground Conductors & Devices	PLT_367	INTERNAL	148,586	112,645	0	35,941	0	0	112,645	90,455	22,190	0
RBD	13	368-Line Transformers	PLT_368	INTERNAL	150,614	150,614	0	0	0	0	150,614	0	0	0
RBD	14	369-Services	PLT_369	INTERNAL	227,180	0	0	227,180	0	0	0	0	0	0
RBD	15	370-Meters	PLT_370	INTERNAL	274,521	0	0	274,521	0	0	0	0	0	0
RBD	16	371-Installation on Customer Premises	PLT_371	INTERNAL	11,947	0	0	11,947	0	0	0	0	0	0
RBD	17	373-Street Lighting & Signal Systems	PLT_373	INTERNAL	38,073	0	0	38,073	0	0	0	0	0	0
RBD	18	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	INTERNAL	2,749	2,032	0	717	0	0	2,032	1,398	384	0
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPREC			2,134,385	1,400,979	0	733,405	0	0	1,400,979	1,112,801	137,314	0
RBD														
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATIO	ENSTORPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBD														
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	INTERNAL	89,294	45,032	0	44,262	0	0	45,032	32,956	10,894	0
RBD														
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**			2,223,678	1,446,011	0	777,667	0	0	1,446,011	1,145,757	148,208	0
RBD														
RBD														
RBD														
RBD	23	**NET ELECTRIC PLANT IN SERVICE**			10,930,908	8,309,402	0	2,621,506	0	0	8,309,402	5,674,417	1,638,703	0
RBD														
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RBD														
RBD														
RBD														
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**												
RBO														
RBO	2	**PLUS: ADDITIONS TO RATE BASE**												
RBO														
RBO	3	COMMON PLANT	SALWAGES	INTERNAL	620,339	312,844	0	307,495	0	0	312,844	228,949	75,681	0
RBO	4	Pension Assets / (Liability)	SALWAGES	INTERNAL	161,288	81,339	0	79,949	0	0	81,339	59,527	19,677	0
RBO														

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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBP													
RBD	1	**LESS: ACCUMULATED DEPRECIATION**											
RBD													
RBD	2	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	INTPLT	INTERNAL	0	0	0	0	0	0	0	0	0
RBD													
RBD	3	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	TRANPLT	INTERNAL	0	0	0	0	0	0	0	0	0
RBD													
RBD	4	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION											
RBD	5	360-Land & Land Rights	PLT_360	INTERNAL	0	0	0	0	0	0	0	0	0
RBD	6	361-Structures & Improvements	PLT_361	INTERNAL	0	0	0	0	0	0	0	0	0
RBD	7	362-Station Equipment	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
RBD	8	363-Computer HW SW and Equipment	PLT_363	INTERNAL	0	0	0	0	0	0	0	0	0
RBD	9	364-Poles,Towers & Fixtures	PLT_364	INTERNAL	0	0	0	(816)	0	0	0	0	0
RBD	10	365-Overhead Conductors & Devices	PLT_365	INTERNAL	0	0	0	91,340	0	0	0	0	0
RBD	11	366-Underground Conduit	PLT_366	INTERNAL	0	0	0	54,502	0	0	0	0	0
RBD	12	367-Underground Conductors & Devices	PLT_367	INTERNAL	0	0	0	35,941	0	0	0	0	0
RBD	13	368-Line Transformers	PLT_368	INTERNAL	150,614	0	0	0	0	0	0	0	0
RBD	14	369-Services	PLT_369	INTERNAL	0	0	0	0	227,180	0	0	0	0
RBD	15	370-Meters	PLT_370	INTERNAL	0	0	0	0	0	274,521	0	0	0
RBD	16	371-Installation on Customer Premises	PLT_371	INTERNAL	0	0	0	0	0	0	0	0	11,947
RBD	17	373-Street Lighting & Signal Systems	PLT_373	INTERNAL	0	0	0	0	0	0	0	0	38,073
RBD	18	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	INTERNAL	250	0	0	495	113	90	0	0	19
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPREC			150,864	0	0	181,462	227,293	274,611	0	0	50,039
RBD													
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATIO	ENSTORPLT	INTERNAL	0	0	0	0	0	0	0	0	0
RBD													
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	INTERNAL	1,182	0	0	13,260	301	1,957	23,476	993	4,274
RBD													
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**			152,046	0	0	194,723	227,594	276,568	23,476	993	54,313
RBD													
RBD													
RBD													
RBD	23	**NET ELECTRIC PLANT IN SERVICE**			996,282	0	0	2,104,752	289,962	148,152	32,299	1,366	44,975
RBD													
RBD													
RBD													
RBD													
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RBD													
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**											
RBO													
RBO	2	**PLUS: ADDITIONS TO RATE BASE**											
RBO													
RBO	3	COMMON PLANT	SALWAGES	INTERNAL	8,215	0	0	92,122	2,093	13,598	163,089	6,900	29,693
RBO	4	Pension Assets / (Liability)	SALWAGES	INTERNAL	2,136	0	0	23,952	544	3,536	42,403	1,794	7,720
RBO													

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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
RBO	5	**WORKING CAPITAL**												
RBO	6	Purchased Power Cash Working Capital			91,220	0	91,220	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital			12,703	12,703	0	0	0	12,703	0	0	0	0
RBO	8	Distribution												
RBO	9	Cash Working Capital			237,794	158,077	2,900	76,817	0	11,987	146,089	109,516	27,621	0
RBO	10	Materials and Supplies	TOTPLT	INTERNAL	53,088	39,370	0	13,718	0	0	39,370	27,524	7,211	0
RBO	11	Total Distribution Working Capital			290,882	197,447	2,900	90,536	0	11,987	185,460	137,040	34,833	0
RBO	12	TOTAL WORKING CAPITAL			394,805	210,150	94,119	90,536	0	24,690	185,460	137,040	34,833	0
RBO	13	TOTAL ADDITIONS TO RATE BASE			1,176,432	604,333	94,119	477,980	0	24,690	579,643	425,516	130,191	0
RBO														
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**												
RBO	15	Customer Deposits	CUSTDEP	EXTERNAL	66,853	0	0	66,853	0	0	0	0	0	0
RBO	16	Customer Advances for Construction	CUSTADV	INTERNAL	10,468	7,731	0	2,736	0	0	7,731	5,606	2,125	0
RBO	17	Deferred Income Taxes and Credits												
RBO	18	Plant	TOTPLT	INTERNAL	1,006,714	746,577	0	260,137	0	0	746,577	521,945	136,751	0
RBO	19	Common Plant	SALWAGES	INTERNAL	91,299	46,043	0	45,256	0	0	46,043	33,696	11,138	0
RBO	20	Corporate Alternative Minimum Tax	TOTPLT	INTERNAL	(12,621)	(9,360)	0	(3,261)	0	0	(9,360)	(6,544)	(1,714)	0
RBO	21	Unamortized AMR Investment	CMETERS	EXTERNAL	0	0	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	CUSTADV	INTERNAL	(8,940)	(6,603)	0	(2,337)	0	0	(6,603)	(4,788)	(1,815)	0
RBO	23	Unamortized Payment for BESS	CUSTADVRRI	INTERNAL	1,890	1,243	0	647	0	0	1,243	823	421	0
RBO	24	Total Deferred Income Taxes and Credits			1,076,453	776,658	0	299,795	0	0	776,658	544,309	144,361	0
RBO	25	TOTAL DEDUCTIONS TO RATE BASE			1,155,663	785,632	0	370,031	0	0	785,632	550,738	146,906	0
RBO														
RBO														
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE			1,072,510	591,630	2,900	477,980	0	11,987	579,643	425,516	130,191	0
RBO														
RBO	27	TOTAL PURCHASED POWER RATE BASE			91,220	0	91,220	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE			12,703	12,703	0	0	0	12,703	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE			10,847,754	8,115,400	2,900	2,729,454	0	11,987	8,103,413	5,549,195	1,621,988	0
RBO														
RBO	30	**TOTAL RATE BASE**			10,951,677	8,128,103	94,119	2,729,454	0	24,690	8,103,413	5,549,195	1,621,988	0
RBO														
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RBO														
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**												
RBC	2	**DISTRIBUTION**												
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL												
RBC	4	Payroll (Distribution Only)	SALWAGES	INTERNAL	187,276	94,445	0	92,831	0	0	94,445	69,118	22,847	0
RBC	5	Pension	SALWAGES	INTERNAL	2,988	1,507	0	1,481	0	0	1,507	1,103	365	0
RBC	6	Other Expenses	OMXPPPP	INTERNAL	734,716	483,303	3,221	248,191	0	192,041	291,263	205,587	72,027	0
RBC	7	TOTAL EXPENSES			924,980	579,256	3,221	342,503	0	192,041	387,215	275,808	95,239	0
RBC	8	POR Working Capital	POR	INTERNAL	1,428,686	1,093,003	8,406	327,277	0	1,197	1,091,806	861,436	164,901	0
RBC	9	TOTAL EXPENSES PER DAY			6,448	4,582	32	1,835	0	529	4,052	3,116	713	0
RBC														
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG			141,842	100,777	701	40,364	0	11,645	89,132	68,535	15,677	0
RBC														
RBC	11	AVERAGE PREPAYMENTS			8,432	3,540	1,707	3,185	0	255	3,285	2,319	752	0
RBC	12	DISTRIBUTION ACCRUED TAXES			110,012	70,439	492	39,081	0	87	70,352	50,323	14,248	0
RBC	13	INTEREST PAYMENTS	TOTPLT	INTERNAL	(22,491)	(16,679)	0	(5,812)	0	0	(16,679)	(11,661)	(3,055)	0
RBC														
RBC														
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIRE!			237,794	158,077	2,900	76,817	0	11,987	146,089	109,516	27,621	0
RBC														
RBC														

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
RBO	5	**WORKING CAPITAL**											
RBO	6	Purchased Power Cash Working Capital			0	91,220	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital			0	0	0	0	0	0	0	0	0
RBO	8	Distribution											
RBO	9	Cash Working Capital			8,952	2,900	0	29,828	2,541	8,077	26,342	5,807	4,222
RBO	10	Materials and Supplies	TOTPLT	INTERNAL	4,634	0	0	9,280	2,089	1,714	225	10	401
RBO	11	Total Distribution Working Capital			13,586	2,900	0	39,109	4,630	9,791	26,567	5,816	4,622
RBO	12	TOTAL WORKING CAPITAL			13,586	94,119	0	39,109	4,630	9,791	26,567	5,816	4,622
RBO	13	TOTAL ADDITIONS TO RATE BASE			23,936	94,119	0	155,182	7,267	26,925	232,060	14,510	42,035
RBO													
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**											
RBO	15	Customer Deposits	CUSTDEP	EXTERNAL	0	0	0	0	0	0	0	0	66,853
RBO	16	Customer Advances for Construction	CUSTADV	INTERNAL	0	0	0	2,736	0	0	0	0	0
RBO	17	Deferred Income Taxes and Credits											
RBO	18	Plant	TOTPLT	INTERNAL	87,881	0	0	175,978	39,608	32,504	4,268	181	7,598
RBO	19	Common Plant	SALWAGES	INTERNAL	1,209	0	0	13,558	308	2,001	24,003	1,016	4,370
RBO	20	Corporate Alternative Minimum Tax	TOTPLT	INTERNAL	(1,102)	0	0	(2,206)	(497)	(407)	(54)	(2)	(95)
RBO	21	Unamortized AMR Investment	CMETERS	EXTERNAL	0	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	CUSTADV	INTERNAL	0	0	0	(2,337)	0	0	0	0	0
RBO	23	Unamortized Payment for BESS	CUSTADVRRI	INTERNAL	0	0	0	647	0	0	0	0	0
RBO	24	Total Deferred Income Taxes and Credits			87,988	0	0	184,993	39,420	34,098	28,218	1,194	11,873
RBO	25	TOTAL DEDUCTIONS TO RATE BASE			87,988	0	0	188,376	39,420	34,098	28,218	1,194	78,726
RBO													
RBO													
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE			23,936	2,900	0	155,182	7,267	26,925	232,060	14,510	42,035
RBO													
RBO	27	TOTAL PURCHASED POWER RATE BASE			0	91,220	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE			0	0	0	0	0	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE			932,230	2,900	0	2,071,557	257,809	140,980	236,141	14,683	8,283
RBO													
RBO	30	**TOTAL RATE BASE**			932,230	94,119	0	2,071,557	257,809	140,980	236,141	14,683	8,283
RBO													
RBO													
RBO													
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RBO													
RBO													
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**											
RBC	2	**DISTRIBUTION**											
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	4	Payroll (Distribution Only)	SALWAGES	INTERNAL	2,480	0	0	27,811	632	4,105	49,235	2,083	8,964
RBC	5	Pension	SALWAGES	INTERNAL	40	0	0	444	10	66	786	33	143
RBC	6	Other Expenses	OMXPPPP	INTERNAL	13,649	3,221	0	87,228	4,602	11,190	96,927	34,375	13,868
RBC	7	TOTAL EXPENSES			16,168	3,221	0	115,482	5,244	15,361	146,948	36,491	22,975
RBC	8	POR Working Capital	POR	INTERNAL	65,470	8,406	0	132,124	22,927	52,224	95,902	18,182	5,918
RBC	9	TOTAL EXPENSES PER DAY			224	32	0	678	77	185	665	150	79
RBC													
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG			4,920	701	0	14,922	1,698	4,073	14,635	3,295	1,741
RBC													
RBC	11	AVERAGE PREPAYMENTS			215	1,707	0	920	66	156	757	73	1,212
RBC	12	DISTRIBUTION ACCRUED TAXES			5,781	492	0	17,918	1,662	4,574	11,045	2,444	1,438
RBC	13	INTEREST PAYMENTS	TOTPLT	INTERNAL	(1,963)	0	0	(3,932)	(885)	(726)	(95)	(4)	(170)
RBC													
RBC													
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIRE!			8,952	2,900	0	29,828	2,541	8,077	26,342	5,807	4,222
RBC													
RBC													

PECO Energy Company
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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
RBC	15	**PURCHASED POWER**												
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL												
RBC	17	Commodity Purchased - Contract Purchases	ENERGY1	EXTERNAL	1,501,553	0	1,501,553	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	ENERGY1	EXTERNAL	12,239	0	12,239	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES			1,513,792	0	1,513,792	0	0	0	0	0	0	0
RBC														
RBC	20	TOTAL EXPENSES PER DAY			4,147	0	4,147	0	0	0	0	0	0	0
RBC														
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE L			91,220	0	91,220	0	0	0	0	0	0	0
RBC														
RBC	22	Energy ACCRUED TAXES	ENERGY1	EXTERNAL	0	0	0	0	0	0	0	0	0	0
RBC														
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT			91,220	0	91,220	0	0	0	0	0	0	0
RBC														
RBC	24	**TRANSMISSION**												
RBC	25	O&M EXPENSE - PJM Transmission Purchase	DTRAN	EXTERNAL	102,810	102,810	0	0	0	102,810	0	0	0	0
RBC														
RBC	26	TOTAL EXPENSES PER DAY			282	282	0	0	0	282	0	0	0	0
RBC														
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG			12,703	12,703	0	0	0	12,703	0	0	0	0
RBC														
RBC	28	TRANSMISSION ACCRUED TAXES	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0	0
RBC														
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIRE			12,703	12,703	0	0	0	12,703	0	0	0	0
RBC														
RBC														
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT			341,717	170,780	94,119	76,817	0	24,690	146,089	109,516	27,621	0
RBC														
RBC														
RBC														
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**												
RBC														
RBC	2	**LAG/LEAD DAYS**												
RBC	3	REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	4	EXPENSE LAG DAYS			35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
RBC	5	PURCHASED POWER REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	6	PURCHASED POWER EXP LAG DAYS			35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60
RBC	7	TRANSMISSION REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	8	TRANSMISSION EXP LAG DAYS			12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
RBC	9	DISTRIBUTION REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	10	DISTRIBUTION LAG DAYS			35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60
RBC														
RBC														
RBC														
RBC														
RBC	11	DISTRIBUTION ACCRUED TAXES												
RBC	12	Federal Income Tax	EBT	INTERNAL	1,463,760	1,092,970	507	370,283	0	2,086	1,090,884	752,343	217,894	0
RBC	13	State Income Tax	EBT	INTERNAL	259,962	194,110	90	65,762	0	370	193,740	133,615	38,698	0
RBC	14	PURTA Taxes	PLT_3601	INTERNAL	813,970	813,970	0	0	0	0	813,970	813,970	0	0
RBC	15	Capital Stock	CAPSTOCK	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	PROPREV	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	TOTPLT	INTERNAL	544,299	403,651	0	140,648	0	0	403,651	282,199	73,937	0
RBC	18	PA Corp Loan Tax	TOTPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	SALESREV	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	SALESREV	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	SALESREV	INTERNAL	37,072,413	23,205,465	179,135	13,687,813	0	29,363	23,176,102	16,385,820	4,869,947	0
RBC	22	Lag Day Weighted Accrued Taxes			40,154,403	25,710,165	179,732	14,264,506	0	31,819	25,678,347	18,367,948	5,200,477	0
RBC	23	TOTAL ACCRUED TAXES CWC			110,012	70,439	492	39,081	0	87	70,352	50,323	14,248	0
RBC														
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS												
RBC	25	Customer Experience	CUST	EXTERNAL	173	0	0	173	0	0	0	0	0	0
RBC	26	EEI, EAP and EPRI Dues	PROPREV	INTERNAL	521	220	199	102	0	30	190	133	40	0
RBC	27	PUC Assess - Electric	PROPREV	INTERNAL	3,948	1,666	1,508	774	0	225	1,440	1,009	301	0
RBC	28	Prepaid Rents and Pole Attachment Fees	PLT_364	INTERNAL	417	301	0	116	0	0	301	197	104	0
RBC	29	Land Leasing	DISTPLT	INTERNAL	50	37	0	13	0	0	37	26	7	0
RBC	30	Equipment Maintenance	DISTPLT	INTERNAL	81	60	0	21	0	0	60	42	11	0
RBC	31	Business Support System	CUST	EXTERNAL	464	0	0	464	0	0	0	0	0	0

PECO Energy Company
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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
RBC	15	**PURCHASED POWER**											
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	17	Commodity Purchased - Contract Purchases	ENERGY1	EXTERNAL	0	1,501,553	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	ENERGY1	EXTERNAL	0	12,239	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES			0	1,513,792	0	0	0	0	0	0	0
RBC													
RBC	20	TOTAL EXPENSES PER DAY			0	4,147	0	0	0	0	0	0	0
RBC													
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE L			0	91,220	0	0	0	0	0	0	0
RBC													
RBC	22	Energy ACCRUED TAXES	ENERGY1	EXTERNAL	0	0	0	0	0	0	0	0	0
RBC													
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT			0	91,220	0	0	0	0	0	0	0
RBC													
RBC	24	**TRANSMISSION**											
RBC	25	O&M EXPENSE - PJM Transmission Purchase	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0
RBC													
RBC	26	TOTAL EXPENSES PER DAY			0	0	0	0	0	0	0	0	0
RBC													
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG			0	0	0	0	0	0	0	0	0
RBC													
RBC	28	TRANSMISSION ACCRUED TAXES	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0
RBC													
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIRE			0	0	0	0	0	0	0	0	0
RBC													
RBC													
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT			8,952	94,119	0	29,828	2,541	8,077	26,342	5,807	4,222
RBC													
RBC													
RBC													
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**											
RBC													
RBC	2	**LAG/LEAD DAYS**											
RBC	3	REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	4	EXPENSE LAG DAYS			35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
RBC	5	PURCHASED POWER REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	6	PURCHASED POWER EXP LAG DAYS			35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60
RBC	7	TRANSMISSION REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	8	TRANSMISSION EXP LAG DAYS			12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
RBC	9	DISTRIBUTION REVENUE LAG DAYS			57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60	57.60
RBC	10	DISTRIBUTION LAG DAYS			35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60	35.60
RBC													
RBC													
RBC													
RBC													
RBC	11	DISTRIBUTION ACCRUED TAXES											
RBC	12	Federal Income Tax	EBT	INTERNAL	120,647	507	0	287,585	30,014	10,782	38,953	2,426	525
RBC	13	State Income Tax	EBT	INTERNAL	21,427	90	0	51,075	5,330	1,915	6,918	431	93
RBC	14	PURTA Taxes	PLT_3601	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	15	Capital Stock	CAPSTOCK	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	PROPREV	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	TOTPLT	INTERNAL	47,515	0	0	95,146	21,415	17,574	2,308	98	4,108
RBC	18	PA Corp Loan Tax	TOTPLT	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	SALESREV	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	SALESREV	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	SALESREV	INTERNAL	1,920,334	179,135	0	6,106,227	549,905	1,639,255	3,983,414	888,927	520,086
RBC	22	Lag Day Weighted Accrued Taxes			2,109,922	179,732	0	6,540,032	606,664	1,669,525	4,031,593	891,881	524,812
RBC	23	TOTAL ACCRUED TAXES CWC			5,781	492	0	17,918	1,662	4,574	11,045	2,444	1,438
RBC													
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS											
RBC	25	Customer Experience	CUST	EXTERNAL	0	0	0	0	0	0	0	0	173
RBC	26	EEI, EAP and EPRI Dues	PROPREV	INTERNAL	17	199	0	50	5	11	27	6	3
RBC	27	PUC Assess - Electric	PROPREV	INTERNAL	130	1,508	0	377	36	86	206	45	25
RBC	28	Prepaid Rents and Pole Attachment Fees	PLT_364	INTERNAL	0	0	0	116	0	0	0	0	0
RBC	29	Land Leasing	DISTPLT	INTERNAL	4	0	0	9	2	2	0	0	0
RBC	30	Equipment Maintenance	DISTPLT	INTERNAL	7	0	0	14	3	3	0	0	1
RBC	31	Business Support System	CUST	EXTERNAL	0	0	0	0	0	0	0	0	464

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2027
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Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
RBC	32	VEBA Adjustment	SALWAGES	INTERNAL	1,651	833	0	818	0	0	833	609	201	0
RBC	33	Facilities Contracts	DISTPLT	INTERNAL	36	27	0	9	0	0	27	19	5	0
RBC	34	IT Service Contracts	TOTPLT	INTERNAL	305	226	0	79	0	0	226	158	41	0
RBC	35	Fleet Activities	GENLPLT	INTERNAL	337	170	0	167	0	0	170	125	41	0
RBC	36	Postage	CUSTBILLS	EXTERNAL	449	0	0	449	0	0	0	0	0	0
RBC	37	TOTAL AVERAGE PREPAYMENTS			8,432	3,540	1,707	3,185	0	255	3,285	2,319	752	0
RBC														
RBC														
RBC														
RBC														
RBC														
RBC														
RBC														
RBC	38	**OPERATING REVENUES**												
RBC														
RBC	39	**SALES REVENUES**												
RBC	40	Sales of Electricity Revenues - Base			1,980,591	1,239,750	9,570	731,270	0	1,569	1,238,182	875,411	260,177	0
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	ENERGY2	EXTERNAL	(4,213)	0	(4,213)	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	DTRANR	EXTERNAL	241,020	241,020	0	0	0	241,020	0	0	0	0
RBC	43	Purchased Electric Revenues	ENERGY1	EXTERNAL	1,612,994	0	1,612,994	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY			3,830,392	1,480,771	1,618,351	731,270	0	242,589	1,238,182	875,411	260,177	0
RBC														
RBC	45	**OTHER OPERATING REVENUES**												
RBC	46	Unbilled and Cost Adjustment Revenue	SALESREV	INTERNAL	0	0	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	OX_904	INTERNAL	18,527	10,499	81	7,946	0	15	10,485	6,748	2,679	0
RBC	48	454-Rent from Electric Property	TOTPLT	INTERNAL	27,708	20,548	0	7,160	0	0	20,548	14,365	3,764	0
RBC	49	456-Other Electric Revenues												
RBC	50	Connection Charges/Returned Check Fees/Solar Application I	CUST	EXTERNAL	5,129	0	0	5,129	0	0	0	0	0	0
RBC	51	All Other	DISTPLT	INTERNAL	6,786	5,061	0	1,724	0	0	5,061	3,537	924	0
RBC	52	Total 456-Other Electric Revenues			11,915	5,061	0	6,854	0	0	5,061	3,537	924	0
RBC	53	TOTAL OTHER OPERATING REV			58,150	36,109	81	21,960	0	15	36,094	24,650	7,366	0
RBC														
RBC	54	**TOTAL OPERATING REVENUES**			3,888,542	1,516,879	1,618,433	753,230	0	242,604	1,274,276	900,061	267,543	0
RBC														
RBC														
RBC														
RBC														
RBC														
RBC														
RBC													

PECO Energy Company
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For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
RBC	32	VEBA Adjustment	SALWAGES	INTERNAL	22	0	0	245	6	36	434	18	79
RBC	33	Facilities Contracts	DISTPLT	INTERNAL	3	0	0	6	1	1	0	0	0
RBC	34	IT Service Contracts	TOTPLT	INTERNAL	27	0	0	53	12	10	1	0	2
RBC	35	Fleet Activities	GENLPLT	INTERNAL	4	0	0	50	1	7	89	4	16
RBC	36	Postage	CUSTBILLS	EXTERNAL	0	0	0	0	0	0	0	0	449
RBC	37	TOTAL AVERAGE PREPAYMENTS			215	1,707	0	920	66	156	757	73	1,212
RBC													
RBC													
RBC													
RBC													
RBC													
RBC													
RBC													
RBC	38	**OPERATING REVENUES**											
RBC													
RBC	39	**SALES REVENUES**											
RBC	40	Sales of Electricity Revenues - Base			102,594	9,570	0	326,225	29,379	87,577	212,814	47,491	27,786
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	ENERGY2	EXTERNAL	0	(4,213)	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	DTRANR	EXTERNAL	0	0	0	0	0	0	0	0	0
RBC	43	Purchased Electric Revenues	ENERGY1	EXTERNAL	0	1,612,994	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY			102,594	1,618,351	0	326,225	29,379	87,577	212,814	47,491	27,786
RBC													
RBC	45	**OTHER OPERATING REVENUES**											
RBC	46	Unbilled and Cost Adjustment Revenue	SALESREV	INTERNAL	0	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	OX_904	INTERNAL	1,058	81	0	3,582	280	910	2,368	550	256
RBC	48	454-Rent from Electric Property	TOTPLT	INTERNAL	2,419	0	0	4,843	1,090	895	117	5	209
RBC	49	456-Other Electric Revenues											
RBC	50	Connection Charges/Returned Check Fees/Solar Application I	CUST	EXTERNAL	0	0	0	0	0	0	0	0	5,129
RBC	51	All Other	DISTPLT	INTERNAL	601	0	0	1,190	271	217	0	0	47
RBC	52	Total 456-Other Electric Revenues			601	0	0	1,190	271	217	0	0	5,176
RBC	53	TOTAL OTHER OPERATING REV			4,078	81	0	9,615	1,641	2,022	2,486	555	5,641
RBC													
RBC	54	**TOTAL OPERATING REVENUES**			106,671	1,618,433	0	335,839	31,020	89,599	215,299	48,046	33,426
RBC													
RBC													
RBC													
RBC													
RBC													
RBC													
RBC												

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Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
E	1	**OPERATION & MAINTENANCE EXPENSE**												
E														
E	2	PRODUCTION EXPENSE												
E	3	Other Power Supply												
E	4	555 - Purchased Power - Capacity	ENERGY1	EXTERNAL	1,513,792	0	1,513,792	0	0	0	0	0	0	0
E	5	Total Other Power Supply			1,513,792	0	1,513,792	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE			1,513,792	0	1,513,792	0	0	0	0	0	0	0
E														
E	7	TRANSMISSION EXPENSES												
E	8	Operation Expense	DTRANR	EXTERNAL	225,704	225,704	0	0	0	225,704	0	0	0	0
E	9	Maintenance Expense	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE			225,704	225,704	0	0	0	225,704	0	0	0	0
E														
E	11	DISTRIBUTION EXPENSES												
E	12	Operation												
E	13	Account 577 - Energy Storage Expense - Operation												
E	14	577.1 Operation Supervision and Engineering	SALWAGDO	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	SALWAGDO	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	ENERGY1	EXTERNAL	0	0	0	0	0	0	0	0	0	0
E	17	577.4 Rents	DISTPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	DISTPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	19	Total Account 577			0	0	0	0	0	0	0	0	0	0
E	20	580-Supervision	SALWAGDO	INTERNAL	577	262	0	314	0	0	262	187	57	0
E	21	581-Load Dispatch	DISTPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	PLT_362	INTERNAL	7,147	7,147	0	0	0	0	7,147	7,147	0	0
E	23	583-Overhead Lines	OHDIST	INTERNAL	17,832	12,870	0	4,962	0	0	12,870	8,425	4,445	0
E	24	584-Underground Lines	UGDIST	INTERNAL	11,466	8,693	0	2,774	0	0	8,693	6,980	1,712	0
E	25	585-Street Lighting	PLT_3713	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	26	586-Metering	CMETERS	EXTERNAL	6,490	0	0	6,490	0	0	0	0	0	0
E	27	587-Customer Installations	CUST	EXTERNAL	13,367	0	0	13,367	0	0	0	0	0	0
E	28	588-Miscellaneous	DISTPLT	INTERNAL	89,634	66,857	0	22,777	0	0	66,857	46,717	12,203	0
E	29	589-Rents	DISTPLT	INTERNAL	4,105	3,062	0	1,043	0	0	3,062	2,140	559	0
E	30	Total Distribution Operation			150,619	98,892	0	51,727	0	0	98,892	71,596	18,976	0
E														
E	31	Maintenance												
E	32	578 - Energy Storage Expense - Maintenance												
E	33	578.1 Maintenance Supervision and Engineering (Major Only	SALWAGDM	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structu	MX_578.2	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	MX_578.3	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	MX_578.4	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Onl	MX_578.5	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Pl	MX_578.6	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor	MX_578.7	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	40	Total Account 578			0	0	0	0	0	0	0	0	0	0
E	41	590-Supervision	SALWAGDM	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	42	591-Structures	PLT_361	INTERNAL	7,254	7,254	0	0	0	0	7,254	7,254	0	0
E	43	592-Station Equipment												
E	44	592.1-Structures and Equipment	PLT_362	INTERNAL	17,283	17,283	0	0	0	0	17,283	17,283	0	0
E	45	592.2-Computer Hardware	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	48	Total Account 592			17,283	17,283	0	0	0	0	17,283	17,283	0	0
E	49	593-Overhead Lines	OHDIST	INTERNAL	202,158	145,906	0	56,252	0	0	145,906	95,515	50,391	0
E	50	594-Underground Lines	UGDIST	INTERNAL	36,494	27,667	0	8,827	0	0	27,667	22,217	5,450	0
E	51	595-Transformers	PLT_368	INTERNAL	2,640	2,640	0	0	0	0	2,640	0	0	0
E	52	596-Street Lighting	PLT_373	INTERNAL	1,828	0	0	1,828	0	0	0	0	0	0
E	53	597-Metering	CMETERS	EXTERNAL	0	0	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	DISTPLT	INTERNAL	17,638	13,156	0	4,482	0	0	13,156	9,193	2,401	0
E	55	Total Distribution Maintenance			285,295	213,906	0	71,389	0	0	213,906	151,463	58,242	0
E														
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES			435,914	312,798	0	123,116	0	0	312,798	223,059	77,218	0
E	57	TOTAL PURCHASED POWER O&M EXPENSES			1,513,792	0	1,513,792	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES			225,704	225,704	0	0	0	225,704	0	0	0	0
E														
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)			2,175,410	538,503	1,513,792	123,116	0	225,704	312,798	223,059	77,218	0
E														
E														

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Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
E	1	**OPERATION & MAINTENANCE EXPENSE**											
E													
E	2	PRODUCTION EXPENSE											
E	3	Other Power Supply											
E	4	555 - Purchased Power - Capacity	ENERGY1	EXTERNAL	0	1,513,792	0	0	0	0	0	0	0
E	5	Total Other Power Supply			0	1,513,792	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE			0	1,513,792	0	0	0	0	0	0	0
E													
E	7	TRANSMISSION EXPENSES											
E	8	Operation Expense	DTRANR	EXTERNAL	0	0	0	0	0	0	0	0	0
E	9	Maintenance Expense	DTRAN	EXTERNAL	0	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE			0	0	0	0	0	0	0	0	0
E													
E	11	DISTRIBUTION EXPENSES											
E	12	Operation											
E	13	Account 577 - Energy Storage Expense - Operation											
E	14	577.1 Operation Supervision and Engineering	SALWAGDO	INTERNAL	0	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	SALWAGDO	INTERNAL	0	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	ENERGY1	EXTERNAL	0	0	0	0	0	0	0	0	0
E	17	577.4 Rents	DISTPLT	INTERNAL	0	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	DISTPLT	INTERNAL	0	0	0	0	0	0	0	0	0
E	19	Total Account 577			0	0	0	0	0	0	0	0	0
E	20	580-Supervision	SALWAGDO	INTERNAL	18	0	0	74	8	72	0	0	159
E	21	581-Load Dispatch	DISTPLT	INTERNAL	0	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
E	23	583-Overhead Lines	OHDIST	INTERNAL	0	0	0	4,962	0	0	0	0	0
E	24	584-Underground Lines	UGDIST	INTERNAL	0	0	0	2,774	0	0	0	0	0
E	25	585-Street Lighting	PLT_3713	INTERNAL	0	0	0	0	0	0	0	0	0
E	26	586-Metering	CMETERS	EXTERNAL	0	0	0	0	0	6,490	0	0	0
E	27	587-Customer Installations	CUST	EXTERNAL	0	0	0	0	0	0	0	0	13,367
E	28	588-Miscellaneous	DISTPLT	INTERNAL	7,938	0	0	15,715	3,581	2,863	0	0	618
E	29	589-Rents	DISTPLT	INTERNAL	364	0	0	720	164	131	0	0	28
E	30	Total Distribution Operation			8,319	0	0	24,245	3,754	9,556	0	0	14,172
E													
E	31	Maintenance											
E	32	578 - Energy Storage Expense - Maintenance											
E	33	578.1 Maintenance Supervision and Engineering (Major Only	SALWAGDM	INTERNAL	0	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structu	MX_578.2	INTERNAL	0	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	MX_578.3	INTERNAL	0	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	MX_578.4	INTERNAL	0	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Onl	MX_578.5	INTERNAL	0	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Pl	MX_578.6	INTERNAL	0	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor	MX_578.7	INTERNAL	0	0	0	0	0	0	0	0	0
E	40	Total Account 578			0	0	0	0	0	0	0	0	0
E	41	590-Supervision	SALWAGDM	INTERNAL	0	0	0	0	0	0	0	0	0
E	42	591-Structures	PLT_361	INTERNAL	0	0	0	0	0	0	0	0	0
E	43	592-Station Equipment											
E	44	592.1-Structures and Equipment	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
E	45	592.2-Computer Hardware	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
E	48	Total Account 592			0	0	0	0	0	0	0	0	0
E	49	593-Overhead Lines	OHDIST	INTERNAL	0	0	0	56,252	0	0	0	0	0
E	50	594-Underground Lines	UGDIST	INTERNAL	0	0	0	8,827	0	0	0	0	0
E	51	595-Transformers	PLT_368	INTERNAL	2,640	0	0	0	0	0	0	0	0
E	52	596-Street Lighting	PLT_373	INTERNAL	0	0	0	0	0	0	0	0	1,828
E	53	597-Metering	CMETERS	EXTERNAL	0	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	DISTPLT	INTERNAL	1,562	0	0	3,092	705	563	0	0	122
E	55	Total Distribution Maintenance			4,202	0	0	68,172	705	563	0	0	1,949
E													
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES			12,521	0	0	92,417	4,458	10,119	0	0	16,121
E	57	TOTAL PURCHASED POWER O&M EXPENSES			0	1,513,792	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES			0	0	0	0	0	0	0	0	0
E													
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)			12,521	1,513,792	0	92,417	4,458	10,119	0	0	16,121
E													
E													

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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
E														
E														
E														
E														
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**												
E														
E	61	CUSTOMER ACCOUNTS EXPENSES												
E	62	901-Supervision	SALWAGCA	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	63	902-Meter Reading	CMETERS	EXTERNAL	250	0	0	250	0	0	0	0	0	0
E	64	903-Customer Records and Collection Expense	CUSTREC	EXTERNAL	102,973	0	0	102,973	0	0	0	0	0	0
E	65	904-Uncollectible Accounts	EXP_904	INTERNAL	58,726	33,280	258	25,188	0	47	33,233	21,389	8,491	0
E	66	905-Miscellaneous CA	CUSTCAM	EXTERNAL	6,859	0	0	6,859	0	0	0	0	0	0
E	67	TOTAL CUSTOMER ACCTS EXPENSE			168,808	33,280	258	135,270	0	47	33,233	21,389	8,491	0
E														
E														
E	68	CUSTOMER SERVICE EXPENSES												
E	69	907-Supervision	SALWAGCS	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	70	908-Customer Assistance	CUSTASST	EXTERNAL	35,434	0	0	35,434	0	0	0	0	0	0
E	71	909-Informational Advertisement	CUSTADVT	EXTERNAL	2,438	0	0	2,438	0	0	0	0	0	0
E	72	910-Miscellaneous CS	CUSTCSM	EXTERNAL	935	0	0	935	0	0	0	0	0	0
E	73	TOTAL CUSTOMER SERVICE EXPENSE			38,807	0	0	38,807	0	0	0	0	0	0
E														
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	CUSTSALES	EXTERNAL	734	0	0	734	0	0	0	0	0	0
E														
E	75	TOTAL OPER & MAINT EXCL A&G			2,383,760	571,782	1,514,050	297,927	0	225,751	346,031	244,448	85,709	0
E														
E	76	ADMINISTRATIVE & GENERAL EXPENSE												
E	77	920-Administrative Salaries	SALWAGES	INTERNAL	39,282	19,811	0	19,472	0	0	19,811	14,498	4,792	0
E	78	921-Office Supplies & Expense	SALWAGES	INTERNAL	4,273	2,155	0	2,118	0	0	2,155	1,577	521	0
E	79	923-Outside Service Employed	SALWAGES	INTERNAL	101,338	51,106	0	50,232	0	0	51,106	37,401	12,363	0
E	80	924-Property Insurance	DGPLT	INTERNAL	970	720	0	250	0	0	720	503	132	0
E	81	925-Injuries and Damages	SALWAGES	INTERNAL	18,625	9,393	0	9,232	0	0	9,393	6,874	2,272	0
E	82	926-Employee Pensions & Benefits	SALWAGES	INTERNAL	32,797	16,540	0	16,257	0	0	16,540	12,104	4,001	0
E	83	928-Regulatory Commission	PROPREV	INTERNAL	9,851	4,156	3,762	1,932	0	562	3,594	2,519	752	0
E	84	929-Duplicate Charges-Credit	PROPREV	INTERNAL	(2,075)	(876)	(793)	(407)	(0)	(118)	(757)	(531)	(158)	(0)
E	85	930.2-Miscellaneous General												
E	86	R/RH	SREVRRH	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	87	GS	SREVGS	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	88	GS/PD/HT	CUSTCI	EXTERNAL	0	0	0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	CTCREALLR	EXTERNAL	0	0	0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	CTCREALLCI	EXTERNAL	0	0	0	0	0	0	0	0	0	0
E	91	All Other	PROPREV	INTERNAL	1,487	627	568	292	0	85	543	380	113	0
E	92	Total 930.2-Miscellaneous General			1,487	627	568	292	0	85	543	380	113	0
E	93	935-Maintenance of General Plant												
E	94	935-Maintenance of General Plant	GENLPLT	INTERNAL	10,000	5,043	0	4,957	0	0	5,043	3,691	1,220	0
E	95	935.1-Maintenance of Computer Hardware	GENLPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	GENLPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	GENLPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
E	98	Total Account 935			10,000	5,043	0	4,957	0	0	5,043	3,691	1,220	0
E	99	TOTAL A&G EXPENSE			216,547	108,675	3,537	104,335	0	528	108,146	79,016	26,009	0
E														
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EX**			860,811	454,752	3,796	402,263	0	575	454,177	323,464	111,717	0
E														
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**			2,600,307	680,457	1,517,587	402,263	0	226,279	454,177	323,464	111,717	0
E														
E														
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PECO Energy Company
Electric Class Cost of Service Study ($000s)
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Functional Summary

	Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
	(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
E														
E														
E														
E														
E		60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**											
E														
E		61	CUSTOMER ACCOUNTS EXPENSES											
E		62	901-Supervision	SALWAGCA	INTERNAL	0	0	0	0	0	0	0	0	0
E		63	902-Meter Reading	CMETERS	EXTERNAL	0	0	0	0	0	250	0	0	0
E		64	903-Customer Records and Collection Expense	CUSTREC	EXTERNAL	0	0	0	0	0	0	102,973	0	0
E		65	904-Uncollectible Accounts	EXP_904	INTERNAL	3,354	258	0	11,352	888	2,885	7,506	1,745	811
E		66	905-Miscellaneous CA	CUSTCAM	EXTERNAL	0	0	0	0	0	0	6,859	0	0
E		67	TOTAL CUSTOMER ACCTS EXPENSE			3,354	258	0	11,352	888	3,135	117,339	1,745	811
E														
E		68	CUSTOMER SERVICE EXPENSES											
E		69	907-Supervision	SALWAGCS	INTERNAL	0	0	0	0	0	0	0	0	0
E		70	908-Customer Assistance	CUSTASST	EXTERNAL	0	0	0	0	0	0	0	35,434	0
E		71	909-Informational Advertisement	CUSTADVT	EXTERNAL	0	0	0	0	0	0	0	2,438	0
E		72	910-Miscellaneous CS	CUSTCSM	EXTERNAL	0	0	0	0	0	0	0	935	0
E		73	TOTAL CUSTOMER SERVICE EXPENSE			0	0	0	0	0	0	0	38,807	0
E														
E		74	SALES EXPENSES TOTAL (ACCT 912 & 916)	CUSTSALES	EXTERNAL	0	0	0	0	0	0	0	734	0
E														
E		75	TOTAL OPER & MAINT EXCL A&G			15,875	1,514,050	0	103,769	5,347	13,254	117,339	41,286	16,932
E														
E		76	ADMINISTRATIVE & GENERAL EXPENSE											
E		77	920-Administrative Salaries	SALWAGES	INTERNAL	520	0	0	5,834	133	861	10,328	437	1,880
E		78	921-Office Supplies & Expense	SALWAGES	INTERNAL	57	0	0	635	14	94	1,123	48	205
E		79	923-Outside Service Employed	SALWAGES	INTERNAL	1,342	0	0	15,049	342	2,221	26,642	1,127	4,851
E		80	924-Property Insurance	DGPLT	INTERNAL	85	0	0	170	38	31	4	0	7
E		81	925-Injuries and Damages	SALWAGES	INTERNAL	247	0	0	2,766	63	408	4,897	207	891
E		82	926-Employee Pensions & Benefits	SALWAGES	INTERNAL	434	0	0	4,870	111	719	8,622	365	1,570
E		83	928-Regulatory Commission	PROPREV	INTERNAL	324	3,762	0	940	90	215	513	111	63
E		84	929-Duplicate Charges-Credit	PROPREV	INTERNAL	(68)	(793)	(0)	(198)	(19)	(45)	(108)	(23)	(13)
E		85	930.2-Miscellaneous General											
E		86	R/RH	SREVRRH	INTERNAL	0	0	0	0	0	0	0	0	0
E		87	GS	SREVGS	INTERNAL	0	0	0	0	0	0	0	0	0
E		88	GS/PD/HT	CUSTCI	EXTERNAL	0	0	0	0	0	0	0	0	0
E		89	Transit Charging - GS	CTCREALLR	EXTERNAL	0	0	0	0	0	0	0	0	0
E		90	Transit Charging - PD/HT	CTCREALLCI	EXTERNAL	0	0	0	0	0	0	0	0	0
E		91	All Other	PROPREV	INTERNAL	49	568	0	142	14	32	77	17	10
E		92	Total 930.2-Miscellaneous General			49	568	0	142	14	32	77	17	10
E		93	935-Maintenance of General Plant											
E		94	935-Maintenance of General Plant	GENLPLT	INTERNAL	132	0	0	1,485	34	219	2,629	111	479
E		95	935.1-Maintenance of Computer Hardware	GENLPLT	INTERNAL	0	0	0	0	0	0	0	0	0
E		96	935.2-Maintenance of Computer Software	GENLPLT	INTERNAL	0	0	0	0	0	0	0	0	0
E		97	935.3-Maintenance of Communication Equipment	GENLPLT	INTERNAL	0	0	0	0	0	0	0	0	0
E		98	Total Account 935			132	0	0	1,485	34	219	2,629	111	479
E		99	TOTAL A&G EXPENSE			3,121	3,537	0	31,692	819	4,756	54,728	2,399	9,942
E														
E		100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EX**			18,996	3,796	0	135,461	6,165	18,010	172,066	43,686	26,875
E														
E		101	**TOTAL OPERATION & MAINTENANCE EXPENSES**			18,996	1,517,587	0	135,461	6,165	18,010	172,066	43,686	26,875
E														
E														
E														
E														

PECO Energy Company
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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**												
D														
D	2	INTANGIBLE PLANT EXPENSE	INTPLT	INTERNAL	38,758	584	0	38,174	0	0	584	408	107	0
D														
D	3	TRANSMISSION PLANT EXPENSE	TRANPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
D														
D	4	DISTRIBUTION PLANT EXPENSE												
D	5	360-Land & Land Rights	PLT_360	INTERNAL	0	0	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	PLT_361	INTERNAL	6,864	6,864	0	0	0	0	6,864	6,864	0	0
D	7	362-Station Equipment	PLT_362	INTERNAL	25,182	25,182	0	0	0	0	25,182	25,182	0	0
D	8	363-Computer HW SW and Equipment	PLT_363	INTERNAL	38,928	38,928	0	0	0	0	38,928	38,928	0	0
D	9	364-Poles,Towers & Fixtures	PLT_364	INTERNAL	47,519	34,297	0	13,223	0	0	34,297	22,452	11,845	0
D	10	365-Overhead Conductors & Devices	PLT_365	INTERNAL	62,747	45,287	0	17,460	0	0	45,287	29,647	15,641	0
D	11	366-Underground Conduit	PLT_366	INTERNAL	23,194	17,584	0	5,610	0	0	17,584	14,120	3,464	0
D	12	367-Underground Conductors & Devices	PLT_367	INTERNAL	60,171	45,617	0	14,555	0	0	45,617	36,631	8,986	0
D	13	368-Line Transformers	PLT_368	INTERNAL	28,173	28,173	0	0	0	0	28,173	0	0	0
D	14	369-Services	PLT_369	INTERNAL	8,825	0	0	8,825	0	0	0	0	0	0
D	15	370-Meters	PLT_370	INTERNAL	20,615	0	0	20,615	0	0	0	0	0	0
D	16	371-Installation on Customer Premises	PLT_371	INTERNAL	0	0	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	PLT_373	INTERNAL	1,551	0	0	1,551	0	0	0	0	0	0
D	18	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	INTERNAL	0	0	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE			323,772	241,933	0	81,839	0	0	241,933	173,824	39,935	0
D														
D	20	ENERGY STORAGE PLANT EXPENSE	ENSTORPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
D														
D	21	GENERAL PLANT EXPENSE	GENLPLT	INTERNAL	45,292	22,841	0	22,451	0	0	22,841	16,716	5,526	0
D														
D	22	BESS DEPRECIATION	CUSTADVRRI	INTERNAL	200	132	0	68	0	0	132	87	44	0
D														
D	23	REG ASSET AMORTIZATION	TOTPLT	INTERNAL	16,572	12,290	0	4,282	0	0	12,290	8,592	2,251	0
D														
D														
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**			424,593	277,779	0	146,814	0	0	277,779	199,627	47,863	0
D														
D														
D													

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**											
D													
D	2	INTANGIBLE PLANT EXPENSE	INTPLT	INTERNAL	69	0	0	137	31	38,000	0	0	5
D													
D	3	TRANSMISSION PLANT EXPENSE	TRANPLT	INTERNAL	0	0	0	0	0	0	0	0	0
D													
D	4	DISTRIBUTION PLANT EXPENSE											
D	5	360-Land & Land Rights	PLT_360	INTERNAL	0	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	PLT_361	INTERNAL	0	0	0	0	0	0	0	0	0
D	7	362-Station Equipment	PLT_362	INTERNAL	0	0	0	0	0	0	0	0	0
D	8	363-Computer HW SW and Equipment	PLT_363	INTERNAL	0	0	0	0	0	0	0	0	0
D	9	364-Poles,Towers & Fixtures	PLT_364	INTERNAL	0	0	0	13,223	0	0	0	0	0
D	10	365-Overhead Conductors & Devices	PLT_365	INTERNAL	0	0	0	17,460	0	0	0	0	0
D	11	366-Underground Conduit	PLT_366	INTERNAL	0	0	0	5,610	0	0	0	0	0
D	12	367-Underground Conductors & Devices	PLT_367	INTERNAL	0	0	0	14,555	0	0	0	0	0
D	13	368-Line Transformers	PLT_368	INTERNAL	28,173	0	0	0	0	0	0	0	0
D	14	369-Services	PLT_369	INTERNAL	0	0	0	0	8,825	0	0	0	0
D	15	370-Meters	PLT_370	INTERNAL	0	0	0	0	0	20,615	0	0	0
D	16	371-Installation on Customer Premises	PLT_371	INTERNAL	0	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	PLT_373	INTERNAL	0	0	0	0	0	0	0	0	1,551
D	18	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	INTERNAL	0	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE			28,173	0	0	50,848	8,825	20,615	0	0	1,551
D													
D	20	ENERGY STORAGE PLANT EXPENSE	ENSTORPLT	INTERNAL	0	0	0	0	0	0	0	0	0
D													
D	21	GENERAL PLANT EXPENSE	GENLPLT	INTERNAL	600	0	0	6,726	153	993	11,907	504	2,168
D													
D	22	BESS DEPRECIATION	CUSTADVRRI	INTERNAL	0	0	0	68	0	0	0	0	0
D													
D	23	REG ASSET AMORTIZATION	TOTPLT	INTERNAL	1,447	0	0	2,897	652	535	70	3	125
D													
D													
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**			30,289	0	0	60,676	9,662	60,143	11,978	507	3,849
D													
D													
D												

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
TO														
TO	13	**GROSS RECEIPTS TAX**												
TO														
TO	14	PURCHASED POWER												
TO	15	Retail Revenue			1,612,994	0	1,612,994	0	0	0	0	0	0	0
TO	16	Forfeited Discounts			0	0	0	0	0	0	0	0	0	0
TO	17	Less: Bad Debt			0	0	0	0	0	0	0	0	0	0
TO	18	Total Purchased Power Revenue			1,612,994	0	1,612,994	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate			95,167	0	95,167	0	0	0	0	0	0	0
TO														
TO	20	TRANSMISSION												
TO	21	Retail Revenue			241,020	241,020	0	0	0	241,020	0	0	0	0
TO	22	Forfeited Discounts			0	0	0	0	0	0	0	0	0	0
TO	23	Less: Bad Debt			0	0	0	0	0	0	0	0	0	0
TO	24	Total Transmission Revenue			241,020	241,020	0	0	0	241,020	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate			14,220	14,220	0	0	0	14,220	0	0	0	0
TO														
TO	26	DISTRIBUTION												
TO	27	Retail Revenue			1,980,591	1,239,750	9,570	731,270	0	1,569	1,238,182	875,411	260,177	0
TO	28	Forfeited Discounts			18,527	10,499	81	7,946	0	15	10,485	6,748	2,679	0
TO	29	Less: Bad Debt			58,726	33,280	258	25,188	0	47	33,233	21,389	8,491	0
TO	30	Total Distribution Revenue			1,940,393	1,216,970	9,394	714,029	0	1,537	1,215,433	860,771	254,365	0
TO	31	Total Distribution at 5.90% GRT Rate			114,483	71,801	554	42,128	0	91	71,711	50,785	15,008	0
TO														
TO	32	TOTAL GROSS RECEIPTS TAX			223,870	86,021	95,721	42,128	0	14,311	71,711	50,785	15,008	0
TO														
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES			95,167	0	95,167	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES			14,220	14,220	0	0	0	14,220	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES			145,002	91,892	1,453	51,657	0	225	91,667	67,052	17,873	0
TO														
TO	36	**TOTAL TAXES OTHER THAN INCOME**			254,389	106,112	96,620	51,657	0	14,445	91,667	67,052	17,873	0
TO														
TO														
TO														
TO														
TO														
TO														
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**												
TI														
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES			2,034,528	1,275,859	5,439	753,230	0	1,583	1,274,276	900,061	267,543	0
TI	3	LESS:												
TI	4	OPERATION & MAINTAINENCE EXPENSE			860,811	454,752	3,796	402,263	0	575	454,177	323,464	111,717	0
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE			424,593	277,779	0	146,814	0	0	277,779	199,627	47,863	0
TI	6	TAXES OTHER THAN INCOME TAXES			145,002	91,892	1,453	51,657	0	225	91,667	67,052	17,873	0
TI	7	NET OPERATING INCOME BEFORE TAXES			604,121	451,436	190	152,496	0	783	450,652	309,919	90,090	0
TI	8	LESS:												
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of D			241,905	180,973	65	60,867	0	267	180,706	123,747	36,170	0
TI														
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**			362,216	270,462	125	91,629	0	516	269,946	186,172	53,919	0
TI														
TI														
TI	11	**CALCULATION OF PA STATE INCOME TAXES**												
TI	12	BASE TAXABLE INCOME			362,216	270,462	125	91,629	0	516	269,946	186,172	53,919	0
TI	13	LESS:												
TI	14	State Tax Depreciation (Over) Under Book	TOTPLT	INTERNAL	(53,322)	(39,543)	0	(13,778)	0	0	(39,543)	(27,645)	(7,243)	0
TI	15	Other Adjustment (state calc.)	TOTPLT	INTERNAL	106,410	78,913	0	27,497	0	0	78,913	55,170	14,455	0
TI	16	Repair Allowance Deduction	TOTPLT	INTERNAL	377,000	279,582	0	97,418	0	0	279,582	195,461	51,211	0
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME			(67,872)	(48,490)	125	(19,507)	0	516	(49,007)	(36,813)	(4,504)	0
TI	18	NOL Utilization	TOTPLT	INTERNAL	39,035	28,948	0	10,087	0	0	28,948	20,238	5,302	0
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**			(2,016)	(1,366)	9	(658)	0	36	(1,402)	(1,159)	56	0
TI	20	**PLUS:**												
TI	21	**DEFERRED STATE INCOME TAXES**												
TI	22	State Deferred Taxes	TOTPLT	INTERNAL	53,652	39,788	0	13,864	0	0	39,788	27,817	7,288	0
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RAT**			3,750	2,781	0	969	0	0	2,781	1,944	509	0
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**			1,735	1,415	9	311	0	36	1,379	786	565	0
TI														

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
TO													
TO	13	**GROSS RECEIPTS TAX**											
TO													
TO	14	PURCHASED POWER											
TO	15	Retail Revenue			0	1,612,994	0	0	0	0	0	0	0
TO	16	Forfeited Discounts			0	0	0	0	0	0	0	0	0
TO	17	Less: Bad Debt			0	0	0	0	0	0	0	0	0
TO	18	Total Purchased Power Revenue			0	1,612,994	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate			0	95,167	0	0	0	0	0	0	0
TO													
TO	20	TRANSMISSION											
TO	21	Retail Revenue			0	0	0	0	0	0	0	0	0
TO	22	Forfeited Discounts			0	0	0	0	0	0	0	0	0
TO	23	Less: Bad Debt			0	0	0	0	0	0	0	0	0
TO	24	Total Transmission Revenue			0	0	0	0	0	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate			0	0	0	0	0	0	0	0	0
TO													
TO	26	DISTRIBUTION											
TO	27	Retail Revenue			102,594	9,570	0	326,225	29,379	87,577	212,814	47,491	27,786
TO	28	Forfeited Discounts			1,058	81	0	3,582	280	910	2,368	550	256
TO	29	Less: Bad Debt			3,354	258	0	11,352	888	2,885	7,506	1,745	811
TO	30	Total Distribution Revenue			100,298	9,394	0	318,454	28,771	85,602	207,676	46,297	27,230
TO	31	Total Distribution at 5.90% GRT Rate			5,918	554	0	18,789	1,697	5,051	12,253	2,731	1,607
TO													
TO	32	TOTAL GROSS RECEIPTS TAX			5,918	95,721	0	18,789	1,697	5,051	12,253	2,731	1,607
TO													
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES			0	95,167	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES			0	0	0	0	0	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES			6,742	1,453	0	22,342	2,017	5,634	16,350	2,926	2,388
TO													
TO	36	**TOTAL TAXES OTHER THAN INCOME**			6,742	96,620	0	22,342	2,017	5,634	16,350	2,926	2,388
TO													
TO													
TO													
TO													
TO													
TO													
TO													
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**											
TI													
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES			106,671	5,439	0	335,839	31,020	89,599	215,299	48,046	33,426
TI	3	LESS:											
TI	4	OPERATION & MAINTAINENCE EXPENSE			18,996	3,796	0	135,461	6,165	18,010	172,066	43,686	26,875
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE			30,289	0	0	60,676	9,662	60,143	11,978	507	3,849
TI	6	TAXES OTHER THAN INCOME TAXES			6,742	1,453	0	22,342	2,017	5,634	16,350	2,926	2,388
TI	7	NET OPERATING INCOME BEFORE TAXES			50,644	190	0	117,360	13,176	5,812	14,905	928	315
TI	8	LESS:											
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of D			20,789	65	0	46,196	5,749	3,144	5,266	327	185
TI													
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**			29,855	125	0	71,165	7,427	2,668	9,639	600	130
TI													
TI													
TI	11	**CALCULATION OF PA STATE INCOME TAXES**											
TI	12	BASE TAXABLE INCOME			29,855	125	0	71,165	7,427	2,668	9,639	600	130
TI	13	LESS:											
TI	14	State Tax Depreciation (Over) Under Book	TOTPLT	INTERNAL	(4,655)	0	0	(9,321)	(2,098)	(1,722)	(226)	(10)	(402)
TI	15	Other Adjustment (state calc.)	TOTPLT	INTERNAL	9,289	0	0	18,601	4,187	3,436	451	19	803
TI	16	Repair Allowance Deduction	TOTPLT	INTERNAL	32,910	0	0	65,901	14,833	12,172	1,598	68	2,846
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME			(7,690)	125	0	(4,017)	(9,494)	(11,218)	7,816	523	(3,116)
TI	18	NOL Utilization	TOTPLT	INTERNAL	3,408	0	0	6,823	1,536	1,260	166	7	295
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**			(299)	9	0	196	(556)	(696)	558	37	(197)
TI	20	**PLUS:**											
TI	21	**DEFERRED STATE INCOME TAXES**											
TI	22	State Deferred Taxes	TOTPLT	INTERNAL	4,684	0	0	9,379	2,111	1,732	227	10	405
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RAT**			327	0	0	656	148	121	16	1	28
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**			28	9	0	852	(409)	(575)	574	38	(169)
TI													

PECO Energy Company
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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**												
TI	26	BASE TAXABLE INCOME			362,216	270,462	125	91,629	0	516	269,946	186,172	53,919	0
TI	27	LESS:												
TI	28	PA State Income Taxes			(2,016)	(1,366)	9	(658)	0	36	(1,402)	(1,159)	56	0
TI	29	Federal Tax Depreciation (Over) Under Book	TOTPLT	INTERNAL	(44,620)	(33,090)	0	(11,530)	0	0	(33,090)	(23,134)	(6,061)	0
TI	30	Other Adjustment (federal calc.)	TOTPLT	INTERNAL	119,882	88,904	0	30,978	0	0	88,904	62,155	16,285	0
TI	31	Repair Allowance Deduction	TOTPLT	INTERNAL	377,000	279,582	0	97,418	0	0	279,582	195,461	51,211	0
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME			(88,030)	(63,568)	117	(24,578)	0	480	(64,048)	(47,151)	(7,572)	0
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**			(18,486)	(13,349)	24	(5,161)	0	101	(13,450)	(9,902)	(1,590)	0
TI	34	**PLUS:**												
TI	35	**DEFERRED FEDERAL INCOME TAXES**												
TI	36	Federal Deferred Taxes	TOTPLT	INTERNAL	159,385	118,200	0	41,185	0	0	118,200	82,635	21,651	0
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX I**			33,471	24,822	0	8,649	0	0	24,822	17,353	4,547	0
TI	38	**LESS:**												
TI	39	**OTHER TAX ADJUSTMENTS**												
TI	40	Electric Plant	TOTPLT	INTERNAL	0	0	0	0	0	0	0	0	0	0
TI	41	Common Plant	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	EBT	INTERNAL	(17)	(13)	(0)	(4)	(0)	(0)	(13)	(9)	(3)	(0)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENS**			15,002	11,485	24	3,492	0	101	11,385	7,461	2,959	0
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**			16,736	12,901	33	3,802	0	137	12,764	8,246	3,524	0
TI														
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**												
TI														
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**												
TI	47	PURCHASED POWER OPERATING REVENUES			1,612,994	0	1,612,994	0	0	0	0	0	0	0
TI	48	LESS:												
TI	49	OPERATION & MAINTAINENCE EXPENSE			1,513,792	0	1,513,792	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES			95,167	0	95,167	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES			4,036	0	4,036	0	0	0	0	0	0	0
TI	52	LESS:												
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of D			2,034	0	2,034	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**			2,001	0	2,001	0	0	0	0	0	0	0
TI	55	LESS:												
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99%**			140	0	140	0	0	0	0	0	0	0
TI	57	EQUALS:												
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00%**			391	0	391	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL			0	0	0	0	0	0	0	0	0	0
TI														
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**												
TI	61	TRANSMISSION OPERATING REVENUES			241,020	241,020	0	0	0	241,020	0	0	0	0
TI	62	LESS:												
TI	63	OPERATION & MAINTAINENCE EXPENSE			225,704	225,704	0	0	0	225,704	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES			14,220	14,220	0	0	0	14,220	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES			1,096	1,096	0	0	0	1,096	0	0	0	0
TI	66	LESS:												
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of D			283	283	0	0	0	283	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**			812	812	0	0	0	812	0	0	0	0
TI	69	LESS:												
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% T**			57	57	0	0	0	57	0	0	0	0
TI	71	EQUALS:												
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% T**			159	159	0	0	0	159	0	0	0	0
TI														
TI	73	**TOTAL PA INCOME TAX EXPENSE**			1,931	1,472	149	311	0	93	1,379	786	565	0
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**			15,551	11,644	415	3,492	0	259	11,385	7,461	2,959	0
TI	75	**TOTAL INCOME TAX EXPENSE**			17,483	13,116	564	3,802	0	352	12,764	8,246	3,524	0
TI														

PECO Energy Company
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Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**											
TI	26	BASE TAXABLE INCOME			29,855	125	0	71,165	7,427	2,668	9,639	600	130
TI	27	LESS:											
TI	28	PA State Income Taxes			(299)	9	0	196	(556)	(696)	558	37	(197)
TI	29	Federal Tax Depreciation (Over) Under Book	TOTPLT	INTERNAL	(3,895)	0	0	(7,800)	(1,756)	(1,441)	(189)	(8)	(337)
TI	30	Other Adjustment (federal calc.)	TOTPLT	INTERNAL	10,465	0	0	20,956	4,717	3,871	508	22	905
TI	31	Repair Allowance Deduction	TOTPLT	INTERNAL	32,910	0	0	65,901	14,833	12,172	1,598	68	2,846
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME			(9,326)	117	0	(8,089)	(9,811)	(11,238)	7,164	482	(3,086)
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**			(1,958)	24	0	(1,699)	(2,060)	(2,360)	1,504	101	(648)
TI	34	**PLUS:**											
TI	35	**DEFERRED FEDERAL INCOME TAXES**											
TI	36	Federal Deferred Taxes	TOTPLT	INTERNAL	13,914	0	0	27,861	6,271	5,146	676	29	1,203
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX I**			2,922	0	0	5,851	1,317	1,081	142	6	253
TI	38	**LESS:**											
TI	39	**OTHER TAX ADJUSTMENTS**											
TI	40	Electric Plant	TOTPLT	INTERNAL	0	0	0	0	0	0	0	0	0
TI	41	Common Plant	SALWAGES	INTERNAL	0	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	EBT	INTERNAL	(1)	(0)	(0)	(3)	(0)	(0)	(0)	(0)	(0)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENS**			965	24	0	4,156	(743)	(1,279)	1,647	107	(396)
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**			993	33	0	5,007	(1,152)	(1,854)	2,221	145	(564)
TI													
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**											
TI													
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**											
TI	47	PURCHASED POWER OPERATING REVENUES			0	1,612,994	0	0	0	0	0	0	0
TI	48	LESS:											
TI	49	OPERATION & MAINTAINENCE EXPENSE			0	1,513,792	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES			0	95,167	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES			0	4,036	0	0	0	0	0	0	0
TI	52	LESS:											
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of D			0	2,034	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**			0	2,001	0	0	0	0	0	0	0
TI	55	LESS:											
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99%**			0	140	0	0	0	0	0	0	0
TI	57	EQUALS:											
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00%**			0	391	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL			0	0	0	0	0	0	0	0	0
TI													
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**											
TI	61	TRANSMISSION OPERATING REVENUES			0	0	0	0	0	0	0	0	0
TI	62	LESS:											
TI	63	OPERATION & MAINTAINENCE EXPENSE			0	0	0	0	0	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES			0	0	0	0	0	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES			0	0	0	0	0	0	0	0	0
TI	66	LESS:											
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of D			0	0	0	0	0	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**			0	0	0	0	0	0	0	0	0
TI	69	LESS:											
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% T**			0	0	0	0	0	0	0	0	0
TI	71	EQUALS:											
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% T**			0	0	0	0	0	0	0	0	0
TI													
TI	73	**TOTAL PA INCOME TAX EXPENSE**			28	149	0	852	(409)	(575)	574	38	(169)
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**			965	415	0	4,156	(743)	(1,279)	1,647	107	(396)
TI	75	**TOTAL INCOME TAX EXPENSE**			993	564	0	5,007	(1,152)	(1,854)	2,221	145	(564)
TI													

PECO Energy Company
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Functional Summary

Sch.	Line No.	Description	Allocator	Allocator Category	Total Electric Division	Demand Total	Energy Total	Customer Total	Production	Transmission	Distribution	DEMDISPHT	DEMDISPRI	DEMDISSEC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
TI														
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TI														
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**												
RRW														
RRW	2	Present Rates												
RRW														
RRW	3	Rate Base ($)			10,847,754	8,115,400	2,900	2,729,454	0	11,987	8,103,413	5,549,195	1,621,988	0
RRW	4	Net Operating Income at Present Rates ($)			587,385	438,535	157	148,693	0	647	437,889	301,673	86,565	0
RRW	5	Rate of Return at Present Rates			5.41%	5.40%	5.41%	5.45%	108.08%	5.39%	5.40%	5.44%	5.34%	92.95%
RRW	6	Relative Rate of Return			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
RRW	7	Sales Revenue at Present Rates ($)			1,980,591	1,239,750	9,570	731,270	0	1,569	1,238,182	875,411	260,177	0
RRW	8	Revenue at Present Rates ($/KWH)			$0.0544	$0.0340	$0.0003	$0.0201	$0.0000	$0.0000	$0.0340	$0.0240	$0.0071	$0.0000
RRW	9	Revenue Required - $/MO/CUST			$95.42	$59.73	$0.46	$35.23	$0.00	$0.08	$59.65	$42.18	$12.53	$0.00
RRW	10	Sales Revenue Required - $/KW			$33.12	$20.73	$0.16	$12.23	$0.00	$0.03	$20.71	$14.64	$4.35	$0.00
RRW														
RRW	11	Proposed Rate of Return												
RRW														
RRW	12	Proposed Rate of Return			8.08%	8.08%	8.08%	8.08%	66.35%	8.08%	8.08%	8.08%	8.08%	64.37%
RRW	13	Return Required for Proposed ROR			876,500	655,725	234	220,540	0	969	654,757	448,375	131,057	0
RRW	14	Sales Revenue Required at Proposed ROR - Distribution			2,403,895	1,557,697	9,750	836,447	0	2,043	1,555,655	1,090,169	325,308	0
RRW	15	Revenue Deficiency Sales Revenue			423,304	317,947	180	105,177	0	474	317,473	214,758	65,131	0
RRW	16	Percent Increase Required			21.37%	25.65%	1.88%	14.38%	61.97%	30.22%	25.64%	24.53%	25.03%	59.48%
RRW	17	Annual Booked kWh Sales			36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039
RRW	18	Sales Revenue Required $/KWH			$0.0660	$0.0428	$0.0003	$0.0230	$0.0000	$0.0001	$0.0427	$0.0299	$0.0089	$0.0000
RRW	19	Revenue Deficiency $/KWH			$0.0116	$0.0087	$0.0000	$0.0029	$0.0000	$0.0000	$0.0087	$0.0059	$0.0018	$0.0000
RRW	20	Sales Revenue Req. at Proposed ROR - Energy			1,618,585	0	1,618,585	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission			241,232	241,232	0	0	0	241,232	0	0	0	0

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Sch.	Line No.	Description	Allocator	Allocator Category	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
(A)	(B)	(C)	(D)	(E)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)
TI													
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RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**											
RRW													
RRW	2	Present Rates											
RRW													
RRW	3	Rate Base ($)			932,230	2,900	0	2,071,557	257,809	140,980	236,141	14,683	8,283
RRW	4	Net Operating Income at Present Rates ($)			49,651	157	0	112,353	14,328	7,666	12,685	783	879
RRW	5	Rate of Return at Present Rates			5.33%	5.41%	91.21%	5.42%	5.56%	5.44%	5.37%	5.33%	10.61%
RRW	6	Relative Rate of Return			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
RRW	7	Sales Revenue at Present Rates ($)			102,594	9,570	0	326,225	29,379	87,577	212,814	47,491	27,786
RRW	8	Revenue at Present Rates ($/KWH)			$0.0028	$0.0003	$0.0000	$0.0090	$0.0008	$0.0024	$0.0058	$0.0013	$0.0008
RRW	9	Revenue Required - $/MO/CUST			$4.94	$0.46	$0.00	$15.72	$1.42	$4.22	$10.25	$2.29	$1.34
RRW	10	Sales Revenue Required - $/KW			$1.72	$0.16	$0.00	$5.46	$0.49	$1.46	$3.56	$0.79	$0.46
RRW													
RRW	11	Proposed Rate of Return											
RRW													
RRW	12	Proposed Rate of Return			8.08%	8.08%	64.43%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR			75,324	234	0	167,382	20,831	11,391	19,080	1,186	669
RRW	14	Sales Revenue Required at Proposed ROR - Distribution			140,177	9,750	0	406,782	38,899	93,030	222,176	48,082	27,478
RRW	15	Revenue Deficiency Sales Revenue			37,584	180	0	80,557	9,520	5,453	9,363	591	(307)
RRW	16	Percent Increase Required			36.63%	1.88%	60.01%	24.69%	32.40%	6.23%	4.40%	1.24%	-1.11%
RRW	17	Annual Booked kWh Sales			36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039	36,412,039
RRW	18	Sales Revenue Required $/KWH			$0.0038	$0.0003	$0.0000	$0.0112	$0.0011	$0.0026	$0.0061	$0.0013	$0.0008
RRW	19	Revenue Deficiency $/KWH			$0.0010	$0.0000	$0.0000	$0.0022	$0.0003	$0.0001	$0.0003	$0.0000	($0.0000)
RRW	20	Sales Revenue Req. at Proposed ROR - Energy			0	1,618,585	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission			0	0	0	0	0	0	0	0	0

PECO Exhibit JD-4:
Unitized Functionally Classified
Revenue Requirement

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Unbundled & Unit-Cost Summary

Line No.	Description	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**PRESENT RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**								
2	**Rate Of Return**	5.41%	5.57%	3.42%	6.02%	6.52%	5.87%	3.05%	7.44%
3	**Revenue Required by Component**								
4	**Demand Components**	1,239,750	582,956	142,126	268,848	8,557	220,429	9,522	7,312
5	Demand Production Component	0	0	0	0	0	0	0	0
6	Demand Transmission Component	1,569	880	168	328	5	183	5	0
7	Demand Distribution Component	1,238,182	582,076	141,958	268,520	8,553	220,246	9,517	7,312
8	Demand Distribution Primary HT	875,411	371,974	91,593	171,335	6,099	220,246	9,517	4,646
9	Demand Distribution Primary	260,177	149,834	37,057	68,965	2,453	0	0	1,867
10	Demand Distribution Secondary	0	0	0	0	0	0	0	0
11	Demand Distribution Transformers	102,594	60,268	13,307	28,220	0	0	0	799
12	**Energy Components**	9,570	4,664	1,154	1,658	41	1,977	58	19
13	Energy Purchased Power & Other	9,570	4,664	1,154	1,658	41	1,977	58	19
14	**Customer Components**	731,270	546,917	76,077	73,733	1,260	11,687	82	21,515
15	Customer Distribution Primary	0	0	0	0	0	0	0	0
16	Customer Distribution Secondary	326,225	251,506	31,483	30,017	0	0	0	13,219
17	Customer Services Investment	29,379	16,062	1,812	11,280	28	196	0	0
18	Customer Meter Investment	87,577	58,920	9,100	14,954	341	4,218	44	0
19	Customer Accounts Expense	212,814	163,443	24,943	15,399	890	7,205	37	897
20	Customer Service Expense	47,491	38,421	5,957	2,431	16	534	0	131
21	Customer Other	27,786	18,565	2,781	(348)	(15)	(466)	1	7,267
22	**Total Company**	1,980,591	1,134,536	219,357	344,238	9,859	234,093	9,662	28,846
23	Annual MWh Sales @ Meter	36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
24	Annual MW - Billed	59,800	0	0	24,978	736	32,343	1,743	0
25	Number of Customer Bills	20,756,557	16,177,098	2,522,699	1,867,855	4,476	33,396	465	150,568
26	Use per Month per Customer	1.75	0.70	1.11	4.04	64.37	413.83	1,004.33	0.90

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Unbundled & Unit-Cost Summary

Line No.	Description	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**PRESENT RATE OF RETURN SUMMARY SCHEDULE - UNIT COST**								
2	**Rate of Return**	5.41%	5.57%	3.42%	6.02%	6.52%	5.87%	3.05%	7.44%
3	**$/kWh**								
4	**Demand Components**	$ 0.0340	$ 0.0514	$ 0.0507	$ 0.0356	$ 0.0297	$ 0.0159	$ 0.0204	$ 0.0537
5	Demand Production Component	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
6	Demand Transmission Component	$ 0.0000	$ 0.0001	$ 0.0001	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
7	Demand Distribution Component	$ 0.0340	$ 0.0513	$ 0.0506	$ 0.0356	$ 0.0297	$ 0.0159	$ 0.0204	$ 0.0537
8	Demand Distribution Primary HT	$ 0.0240	$ 0.0328	$ 0.0327	$ 0.0227	$ 0.0212	$ 0.0159	$ 0.0204	$ 0.0341
9	Demand Distribution Primary	$ 0.0071	$ 0.0132	$ 0.0132	$ 0.0091	$ 0.0085	$ 0.0000	$ 0.0000	$ 0.0137
10	Demand Distribution Secondary	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
11	Demand Distribution Transformers	$ 0.0028	$ 0.0053	$ 0.0047	$ 0.0037	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0059
12	**Energy Components**	$ 0.0003	$ 0.0004	$ 0.0004	$ 0.0002	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
13	Energy Purchased Power & Other	$ 0.0003	$ 0.0004	$ 0.0004	$ 0.0002	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
14	**Customer Components**	$ 0.0201	$ 0.0482	$ 0.0271	$ 0.0098	$ 0.0044	$ 0.0008	$ 0.0002	$ 0.1580
15	Customer Distribution Primary	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
16	Customer Distribution Secondary	$ 0.0090	$ 0.0222	$ 0.0112	$ 0.0040	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0971
17	Customer Services Investment	$ 0.0008	$ 0.0014	$ 0.0006	$ 0.0015	$ 0.0001	$ 0.0000	$ 0.0000	$ 0.0000
18	Customer Meter Investment	$ 0.0024	$ 0.0052	$ 0.0032	$ 0.0020	$ 0.0012	$ 0.0003	$ 0.0001	$ 0.0000
19	Customer Accounts Expense	$ 0.0058	$ 0.0144	$ 0.0089	$ 0.0020	$ 0.0031	$ 0.0005	$ 0.0001	$ 0.0066
20	Customer Service Expense	$ 0.0013	$ 0.0034	$ 0.0021	$ 0.0003	$ 0.0001	$ 0.0000	$ 0.0000	$ 0.0010
21	Customer Other	$ 0.0008	$ 0.0016	$ 0.0010	$ (0.0000)	$ (0.0001)	$ (0.0000)	$ 0.0000	$ 0.0534
22	**Total Company**	$ 0.0544	$ 0.1000	$ 0.0782	$ 0.0456	$ 0.0342	$ 0.0169	$ 0.0207	$ 0.2118
23	**$/KW**								
24	**Demand Components**	$ 20.73	$ -	$ -	$ 10.76	$ 11.62	$ 6.82	$ 5.46	$ -
25	Demand Production Component	$ 0.00	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ -
26	Demand Transmission Component	$ 0.03	$ -	$ -	$ 0.01	$ 0.01	$ 0.01	$ 0.00	$ -
27	Demand Distribution Component	$ 20.71	$ -	$ -	$ 10.75	$ 11.61	$ 6.81	$ 5.46	$ -
28	Demand Distribution Primary HT	$ 14.64	$ -	$ -	$ 6.86	$ 8.28	$ 6.81	$ 5.46	$ -
29	Demand Distribution Primary	$ 4.35	$ -	$ -	$ 2.76	$ 3.33	$ 0.00	$ 0.00	$ -
30	Demand Distribution Secondary	$ 0.00	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ -
31	**$/Month/Customer**								
32	**Customer Components**	$ 35.23	$ 33.81	$ 30.16	$ 39.47	$ 281.56	$ 349.95	$ 176.27	$ 142.89
33	Customer Distribution Primary	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
34	Customer Distribution Secondary	$ 15.72	$ 15.55	$ 12.48	$ 16.07	$ 0.00	$ 0.00	$ 0.00	$ 87.79
35	Customer Services Investment	$ 1.42	$ 0.99	$ 0.72	$ 6.04	$ 6.32	$ 5.87	$ 0.00	$ 0.00
36	Customer Meter Investment	$ 4.22	$ 3.64	$ 3.61	$ 8.01	$ 76.22	$ 126.31	$ 94.53	$ 0.00
37	Customer Accounts Expense	$ 10.25	$ 10.10	$ 9.89	$ 8.24	$ 198.76	$ 215.75	$ 79.76	$ 5.96
38	Customer Service Expense	$ 2.29	$ 2.38	$ 2.36	$ 1.30	$ 3.53	$ 15.98	$ 0.86	$ 0.87
39	Customer Other	$ 1.34	$ 1.15	$ 1.10	$ (0.19)	$ (3.28)	$ (13.96)	$ 1.13	$ 48.27

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Unbundled & Unit-Cost Summary

Line No.	Description	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**PROPOSED RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**								
2	**Rate Of Return**	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
3	**Revenue Required by Component**								
4	**Demand Components**	1,557,697	720,283	220,090	319,788	9,701	264,855	15,285	7,696
5	Demand Production Component	0	0	0	0	0	0	0	0
6	Demand Transmission Component	2,043	1,120	278	400	6	229	9	0
7	Demand Distribution Component	1,555,655	719,162	219,811	319,388	9,695	264,626	15,276	7,696
8	Demand Distribution Primary HT	1,090,169	456,322	139,497	202,648	6,918	264,626	15,276	4,883
9	Demand Distribution Primary	325,308	183,204	56,010	81,357	2,777	0	0	1,960
10	Demand Distribution Secondary	0	0	0	0	0	0	0	0
11	Demand Distribution Transformers	140,177	79,636	24,304	35,384	0	0	0	853
12	**Energy Components**	9,750	4,763	1,191	1,683	41	1,995	58	19
13	Energy Purchased Power & Other	9,750	4,763	1,191	1,683	41	1,995	58	19
14	**Customer Components**	836,447	620,590	97,377	82,543	1,297	12,053	91	22,496
15	Customer Distribution Primary	0	0	0	0	0	0	0	0
16	Customer Distribution Secondary	406,782	309,153	48,172	35,559	0	0	0	13,898
17	Customer Services Investment	38,899	21,191	3,297	14,126	33	251	0	0
18	Customer Meter Investment	93,030	62,344	10,133	15,699	354	4,451	49	0
19	Customer Accounts Expense	222,176	170,012	26,873	15,940	913	7,493	40	906
20	Customer Service Expense	48,082	38,855	6,085	2,457	16	537	0	132
21	Customer Other	27,478	19,034	2,818	(1,238)	(20)	(678)	1	7,560
22	**Total Company**	2,403,895	1,345,635	318,658	404,014	11,039	278,904	15,433	30,211
23	Annual MWh Sales @ Meter	36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
24	Annual MW - Billed	59,800	0	0	24,978	736	32,343	1,743	0
25	Number of Customer Bills	20,756,557	16,177,098	2,522,699	1,867,855	4,476	33,396	465	150,568

PECO Energy Company
Electric Class Cost of Service Study ($000s)
For Fully Projected Future Test Year Ended December 31, 2027
Unbundled & Unit-Cost Summary

Line No.	Description	Total Electric Division	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**PROPOSED RATE OF RETURN SUMMARY SCHEDULE - UNIT COSTS**								
2	**Rate of Return**	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
3	**$/kWh**								
4	**Demand Components**	$ 0.0428	$ 0.0635	$ 0.0785	$ 0.0424	$ 0.0337	$ 0.0192	$ 0.0327	$ 0.0565
5	Demand Production Component	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
6	Demand Transmission Component	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
7	Demand Distribution Component	$ 0.0427	$ 0.0634	$ 0.0784	$ 0.0423	$ 0.0336	$ 0.0191	$ 0.0327	$ 0.0565
8	Demand Distribution Primary HT	$ 0.0299	$ 0.0402	$ 0.0497	$ 0.0268	$ 0.0240	$ 0.0191	$ 0.0327	$ 0.0359
9	Demand Distribution Primary	$ 0.0089	$ 0.0161	$ 0.0200	$ 0.0108	$ 0.0096	$ 0.0000	$ 0.0000	$ 0.0144
10	Demand Distribution Secondary	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
11	Demand Distribution Transformers	$ 0.0038	$ 0.0070	$ 0.0087	$ 0.0047	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0063
12	**Energy Components**	$ 0.0003	$ 0.0004	$ 0.0004	$ 0.0002	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
13	Energy Purchased Power & Other	$ 0.0003	$ 0.0004	$ 0.0004	$ 0.0002	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001
14	**Customer Components**	$ 0.0230	$ 0.0547	$ 0.0347	$ 0.0109	$ 0.0045	$ 0.0009	$ 0.0002	$ 0.1652
15	Customer Distribution Primary	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0000
16	Customer Distribution Secondary	$ 0.0112	$ 0.0272	$ 0.0172	$ 0.0047	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.1021
17	Customer Services Investment	$ 0.0011	$ 0.0019	$ 0.0012	$ 0.0019	$ 0.0001	$ 0.0000	$ 0.0000	$ 0.0000
18	Customer Meter Investment	$ 0.0026	$ 0.0055	$ 0.0036	$ 0.0021	$ 0.0012	$ 0.0003	$ 0.0001	$ 0.0000
19	Customer Accounts Expense	$ 0.0061	$ 0.0150	$ 0.0096	$ 0.0021	$ 0.0032	$ 0.0005	$ 0.0001	$ 0.0067
20	Customer Service Expense	$ 0.0013	$ 0.0034	$ 0.0022	$ 0.0003	$ 0.0001	$ 0.0000	$ 0.0000	$ 0.0010
21	Customer Other	$ 0.0008	$ 0.0017	$ 0.0010	$ (0.0002)	$ (0.0001)	$ (0.0000)	$ 0.0000	$ 0.0555
22	**Total Company**	$ 0.0660	$ 0.1186	$ 0.1136	$ 0.0535	$ 0.0383	$ 0.0202	$ 0.0330	$ 0.2219
23	**$/KW**								
24	**Demand Components**	$ 26.05	$ -	$ -	$ 12.80	$ 13.17	$ 8.19	$ 8.77	$ -
25	Demand Production Component	$ 0.00	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ -
26	Demand Transmission Component	$ 0.03	$ -	$ -	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ -
27	Demand Distribution Component	$ 26.01	$ -	$ -	$ 12.79	$ 13.16	$ 8.18	$ 8.77	$ -
28	Demand Distribution Primary HT	$ 18.23	$ -	$ -	$ 8.11	$ 9.39	$ 8.18	$ 8.77	$ -
29	Demand Distribution Primary	$ 5.44	$ -	$ -	$ 3.26	$ 3.77	$ 0.00	$ 0.00	$ -
30	Demand Distribution Secondary	$ 0.00	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ -
31	**$/Month/Customer**								
32	**Customer Components**	$ 40.30	$ 38.36	$ 38.60	$ 44.19	$ 289.71	$ 360.92	$ 195.14	$ 149.41
33	Customer Distribution Primary	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
34	Customer Distribution Secondary	$ 19.60	$ 19.11	$ 19.10	$ 19.04	$ 0.00	$ 0.00	$ 0.00	$ 92.30
35	Customer Services Investment	$ 1.87	$ 1.31	$ 1.31	$ 7.56	$ 7.47	$ 7.51	$ 0.00	$ 0.00
36	Customer Meter Investment	$ 4.48	$ 3.85	$ 4.02	$ 8.41	$ 79.06	$ 133.27	$ 106.38	$ 0.00
37	Customer Accounts Expense	$ 10.70	$ 10.51	$ 10.65	$ 8.53	$ 204.06	$ 224.36	$ 86.62	$ 6.02
38	Customer Service Expense	$ 2.32	$ 2.40	$ 2.41	$ 1.32	$ 3.55	$ 16.08	$ 0.87	$ 0.88
39	Customer Other	$ 1.32	$ 1.18	$ 1.12	$ (0.66)	$ (4.44)	$ (20.29)	$ 1.27	$ 50.21

PECO Exhibit JD-5:
Customer-Related Revenue Requirement and Customer Charge

Customer-Related Revenue Requirement and Customer Charge

Line	Description	Residential	Residential Heating	Total Residential	General Service	Primary Distribution	High Tension
1	Customer Services Investment ($000)	$ 21,191	$ 3,297	$ 24,488	$ 14,126	$ 33	$ 251
2	Customer Meter Investment ($000)	$ 62,344	$ 10,133	72,477	$ 15,699	$ 354	$ 4,451
3	Customer Accounts ($000)	$ 170,012	$ 26,873	196,885	$ 15,940	$ 913	$ 7,493
4	Customer Services ($000)	$ 38,855	$ 6,085	44,940	$ 2,457	$ 16	$ 537
5	Total Revenue Requirement ($000)	$ 292,402	$ 46,387	$ 338,790	$ 48,222	$ 1,317	$ 12,731
6	Number of Customer Bills	16,177,098	2,522,699	18,699,797	$ 1,867,855	$ 4,476	$ 33,396
7	$/Month/Customer (Line 5/Line 6*1000)	$ 18.08	$ 18.39	$ 18.12	$ 25.82	$ 294.14	$ 381.22

Notes:

1) Above costs included allocated payroll, administrative, pension and benefits and working capital supporting general plant.

2) Line 1 through line 4 from PECO Exhibit JD-4, page 3, lines 17 to 20.

Customer-Related Costs_Detail pages following this page have measures of value by account for line 1 through line 4.

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
S	1	**SUMMARY OF RETURN AT PRESENT RATES**								
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**								
S	3	OPERATING REVENUE								
S	4	Sales of Electricity - Base	0	251,506	16,062	58,920	163,443	38,421	18,565	546,917
S	5	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	6	Other Operating Revenue	0	7,559	931	1,442	2,026	459	4,267	16,683
S	7	TOTAL OPERATING REVENUE	0	259,065	16,993	60,361	165,468	38,880	22,832	563,600
S										
S	8	OPERATING EXPENSES								
S	9	Operation and Maintenance Expense	0	103,651	3,474	12,336	131,996	35,307	18,842	305,605
S	10	Depreciation and Amortization Expense	0	46,065	5,256	40,255	9,156	418	1,662	102,812
S	11	Taxes Other Than Income Taxes-General	0	2,697	174	391	3,132	160	563	7,117
S	12	Taxes Other Than Income Taxes-Distribution GRT	0	14,457	923	3,387	9,395	2,209	1,067	31,439
S	13	Income Taxes	0	4,634	(624)	(1,207)	1,811	127	(13)	4,727
S	14	TOTAL OPERATING EXPENSES	0	171,505	9,203	55,161	155,491	38,221	22,120	451,699
S	15	OPERATING INCOME (RETURN)	0	87,560	7,791	5,201	9,978	659	712	111,901
S										
S	16	DEVELOPMENT OF RATE BASE								
S	17	Electric Plant in Service	0	1,745,464	281,537	284,274	42,637	1,946	20,397	2,376,256
S	18	Less: Accumulated Depreciation	0	147,808	123,805	185,113	17,946	819	12,296	487,788
S	19	Plus: Rate Base Additions	0	116,429	3,493	16,977	175,906	11,691	31,468	355,962
S	20	Less: Rate Base Deductions	0	143,059	21,443	22,822	21,571	985	26,791	236,672
S	21	TOTAL DISTRIBUTION RATE BASE	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
S										
S	22	DISTRIBUTION RATE OF RETURN (PRESENT)	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%
S	23	DISTRIBUTION INDEX RATE OF RETURN (PRESENT)	0.00	1.03	1.00	1.02	1.04	1.05	0.53	1.02
S										
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**								
S	25	Purchased Electric Revenues	0	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income	0	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital	0	0	0	0	0	0	0	0
S	31	PURCHASED POWER RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**								
S	33	Transmission Revenues	0	0	0	0	0	0	0	0
S	34	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	35	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	36	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	37	Transmission Operating Income	0	0	0	0	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital	0	0	0	0	0	0	0	0
S	39	TRANSMISSION RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	40	TOTAL OPERATING INCOME (RETURN)	0	87,560	7,791	5,201	9,978	659	712	111,901
S	41	TOTAL RATE BASE	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
S	42	COMPOSITE RATE OF RETURN AT CURRENT RATES	0.00%	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%
S										
S										
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**								
S	45	RATE BASE	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
S	46	RETURN (= RATE BASE * 8.08% ROR)	0	126,939	11,294	7,540	14,465	956	1,032	162,227
S	47	PLUS:								
S	48	OPERATING EXPENSES								
S	49	Operation and Maintenance Expense	0	104,503	3,550	12,386	132,093	35,314	18,849	306,694

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
S	1	**SUMMARY OF RETURN AT PRESENT RATES**								
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**								
S	3	OPERATING REVENUE								
S	4	Sales of Electricity - Base	0	31,483	1,812	9,100	24,943	5,957	2,781	76,077
S	5	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	6	Other Operating Revenue	0	1,142	140	244	353	82	669	2,631
S	7	TOTAL OPERATING REVENUE	0	32,626	1,952	9,345	25,297	6,039	3,450	78,708
S										
S	8	OPERATING EXPENSES								
S	9	Operation and Maintenance Expense	0	16,048	526	2,033	20,900	5,538	2,949	47,995
S	10	Depreciation and Amortization Expense	0	7,183	820	6,523	1,443	65	259	16,294
S	11	Taxes Other Than Income Taxes-General	0	421	27	63	494	25	88	1,117
S	12	Taxes Other Than Income Taxes-Distribution GRT	0	1,803	104	521	1,428	341	159	4,356
S	13	Income Taxes	0	(1,186)	(267)	(313)	66	6	(24)	(1,719)
S	14	TOTAL OPERATING EXPENSES	0	24,269	1,209	8,828	24,331	5,975	3,431	68,043
S	15	OPERATING INCOME (RETURN)	0	8,357	743	517	966	64	19	10,666
S										
S	16	DEVELOPMENT OF RATE BASE								
S	17	Electric Plant in Service	0	272,192	43,904	46,068	6,718	303	3,181	372,366
S	18	Less: Accumulated Depreciation	0	23,050	19,307	29,998	2,827	128	1,917	77,227
S	19	Plus: Rate Base Additions	0	17,678	497	2,761	27,775	1,851	4,912	55,473
S	20	Less: Rate Base Deductions	0	22,309	3,344	3,698	3,399	154	5,629	38,532
S	21	TOTAL DISTRIBUTION RATE BASE	0	244,511	21,750	15,132	28,267	1,873	547	312,079
S										
S	22	DISTRIBUTION RATE OF RETURN (PRESENT)	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%
S	23	DISTRIBUTION INDEX RATE OF RETURN (PRESENT)	0.00	0.63	0.61	0.63	0.64	0.64	0.32	0.63
S										
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**								
S	25	Purchased Electric Revenues	0	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income	0	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital	0	0	0	0	0	0	0	0
S	31	PURCHASED POWER RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**								
S	33	Transmission Revenues	0	0	0	0	0	0	0	0
S	34	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	35	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	36	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	37	Transmission Operating Income	0	0	0	0	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital	0	0	0	0	0	0	0	0
S	39	TRANSMISSION RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	40	TOTAL OPERATING INCOME (RETURN)	0	8,357	743	517	966	64	19	10,666
S	41	TOTAL RATE BASE	0	244,511	21,750	15,132	28,267	1,873	547	312,079
S	42	COMPOSITE RATE OF RETURN AT CURRENT RATES	0.00%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%
S										
S										
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**								
S	45	RATE BASE	0	244,511	21,750	15,132	28,267	1,873	547	312,079
S	46	RETURN (= RATE BASE * 8.08% ROR)	0	19,757	1,757	1,223	2,284	151	44	25,216
S	47	PLUS:								
S	48	OPERATING EXPENSES								
S	49	Operation and Maintenance Expense	0	16,295	548	2,048	20,929	5,540	2,950	48,309

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
S	1	**SUMMARY OF RETURN AT PRESENT RATES**								
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**								
S	3	OPERATING REVENUE								
S	4	Sales of Electricity - Base	0	30,017	11,280	14,954	15,399	2,431	(348)	73,733
S	5	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	6	Other Operating Revenue	0	702	560	275	97	14	465	2,114
S	7	TOTAL OPERATING REVENUE	0	30,719	11,840	15,228	15,496	2,446	118	75,847
S										
S	8	OPERATING EXPENSES								
S	9	Operation and Maintenance Expense	0	11,427	2,127	2,836	12,155	2,213	2,081	32,838
S	10	Depreciation and Amortization Expense	0	5,312	3,515	10,187	859	22	192	20,087
S	11	Taxes Other Than Income Taxes-General	0	311	116	99	294	9	63	892
S	12	Taxes Other Than Income Taxes-Distribution GRT	0	1,749	657	871	897	142	(20)	4,296
S	13	Income Taxes	0	859	(255)	(252)	212	11	(423)	152
S	14	TOTAL OPERATING EXPENSES	0	19,659	6,160	13,741	14,417	2,396	1,893	58,265
S	15	OPERATING INCOME (RETURN)	0	11,060	5,680	1,488	1,079	50	(1,776)	17,582
S										
S	16	DEVELOPMENT OF RATE BASE								
S	17	Electric Plant in Service	0	201,536	188,298	71,942	3,999	102	2,355	468,232
S	18	Less: Accumulated Depreciation	0	17,066	82,804	46,847	1,683	43	1,420	149,863
S	19	Plus: Rate Base Additions	0	15,727	3,208	5,397	17,637	827	3,407	46,203
S	20	Less: Rate Base Deductions	0	16,453	14,342	5,776	2,023	52	33,839	72,484
S	21	TOTAL DISTRIBUTION RATE BASE	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
S										
S	22	DISTRIBUTION RATE OF RETURN (PRESENT)	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%
S	23	DISTRIBUTION INDEX RATE OF RETURN (PRESENT)	0.00	1.11	1.08	1.11	1.12	1.13	0.57	1.10
S										
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**								
S	25	Purchased Electric Revenues	0	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income	0	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital	0	0	0	0	0	0	0	0
S	31	PURCHASED POWER RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**								
S	33	Transmission Revenues	0	0	0	0	0	0	0	0
S	34	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	35	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	36	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	37	Transmission Operating Income	0	0	0	0	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital	0	0	0	0	0	0	0	0
S	39	TRANSMISSION RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	40	TOTAL OPERATING INCOME (RETURN)	0	11,060	5,680	1,488	1,079	50	(1,776)	17,582
S	41	TOTAL RATE BASE	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
S	42	COMPOSITE RATE OF RETURN AT CURRENT RATES	0.00%	6.02%	6.02%	6.02%	6.02%	6.02%	0.00%	6.02%
S										
S										
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**								
S	45	RATE BASE	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
S	46	RETURN (= RATE BASE * 8.08% ROR)	0	14,846	7,624	1,997	1,449	67	(2,383)	23,601
S	47	PLUS:								
S	48	OPERATING EXPENSES								
S	49	Operation and Maintenance Expense	0	11,509	2,169	2,847	12,163	2,213	2,068	32,969

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
S	1	**SUMMARY OF RETURN AT PRESENT RATES**								
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**								
S	3	OPERATING REVENUE								
S	4	Sales of Electricity - Base	0	0	28	341	890	16	(15)	1,260
S	5	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	6	Other Operating Revenue	0	0	1	4	1	0	1	8
S	7	TOTAL OPERATING REVENUE	0	0	29	346	891	16	(14)	1,268
S										
S	8	OPERATING EXPENSES								
S	9	Operation and Maintenance Expense	0	0	5	59	688	15	5	771
S	10	Depreciation and Amortization Expense	0	0	8	233	51	0	0	293
S	11	Taxes Other Than Income Taxes-General	0	0	0	2	17	0	0	20
S	12	Taxes Other Than Income Taxes-Distribution GRT	0	0	2	20	52	1	(1)	74
S	13	Income Taxes	0	0	(0)	(5)	14	0	(4)	5
S	14	TOTAL OPERATING EXPENSES	0	0	15	309	823	16	1	1,164
S	15	OPERATING INCOME (RETURN)	0	0	15	36	67	0	(15)	104
S										
S	16	DEVELOPMENT OF RATE BASE								
S	17	Electric Plant in Service	0	0	451	1,646	238	0	2	2,338
S	18	Less: Accumulated Depreciation	0	0	198	1,072	100	0	1	1,371
S	19	Plus: Rate Base Additions	0	0	7	113	1,018	3	6	1,147
S	20	Less: Rate Base Deductions	0	0	34	132	121	0	233	521
S	21	TOTAL DISTRIBUTION RATE BASE	0	0	225	555	1,036	3	(226)	1,593
S										
S	22	DISTRIBUTION RATE OF RETURN (PRESENT)	6.52%	6.52%	6.52%	6.52%	6.52%	6.52%	6.52%	6.52%
S	23	DISTRIBUTION INDEX RATE OF RETURN (PRESENT)	0.00	1.20	1.17	1.20	1.21	1.22	0.61	1.20
S										
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**								
S	25	Purchased Electric Revenues	0	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income	0	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital	0	0	0	0	0	0	0	0
S	31	PURCHASED POWER RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**								
S	33	Transmission Revenues	0	0	0	0	0	0	0	0
S	34	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	35	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	36	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	37	Transmission Operating Income	0	0	0	0	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital	0	0	0	0	0	0	0	0
S	39	TRANSMISSION RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	40	TOTAL OPERATING INCOME (RETURN)	0	0	15	36	67	0	(15)	104
S	41	TOTAL RATE BASE	0	0	225	555	1,036	3	(226)	1,593
S	42	COMPOSITE RATE OF RETURN AT CURRENT RATES	0.00%	0.00%	6.52%	6.52%	6.52%	6.52%	0.00%	6.52%
S										
S										
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**								
S	45	RATE BASE	0	0	225	555	1,036	3	(226)	1,593
S	46	RETURN (= RATE BASE * 8.08% ROR)	0	0	18	45	84	0	(18)	129
S	47	PLUS:								
S	48	OPERATING EXPENSES								
S	49	Operation and Maintenance Expense	0	0	5	59	688	15	5	772

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
S	1	**SUMMARY OF RETURN AT PRESENT RATES**								
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**								
S	3	OPERATING REVENUE								
S	4	Sales of Electricity - Base	0	0	196	4,218	7,205	534	(466)	11,687
S	5	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	6	Other Operating Revenue	0	0	9	56	7	0	8	80
S	7	TOTAL OPERATING REVENUE	0	0	205	4,274	7,213	534	(458)	11,767
S										
S	8	OPERATING EXPENSES								
S	9	Operation and Maintenance Expense	0	0	35	738	5,606	494	35	6,908
S	10	Depreciation and Amortization Expense	0	0	63	2,911	417	0	3	3,395
S	11	Taxes Other Than Income Taxes-General	0	0	2	28	143	0	1	174
S	12	Taxes Other Than Income Taxes-Distribution GRT	0	0	12	249	425	31	(27)	689
S	13	Income Taxes	0	0	(5)	(74)	101	1	(86)	(64)
S	14	TOTAL OPERATING EXPENSES	0	0	106	3,852	6,691	528	(74)	11,103
S	15	OPERATING INCOME (RETURN)	0	0	99	422	521	6	(384)	665
S										
S	16	DEVELOPMENT OF RATE BASE								
S	17	Electric Plant in Service	0	0	3,367	20,560	1,942	2	16	25,886
S	18	Less: Accumulated Depreciation	0	0	1,480	13,388	817	1	7	15,693
S	19	Plus: Rate Base Additions	0	0	63	1,666	8,741	103	(25)	10,547
S	20	Less: Rate Base Deductions	0	0	256	1,651	982	1	6,522	9,412
S	21	TOTAL DISTRIBUTION RATE BASE	0	0	1,692	7,187	8,883	103	(6,537)	11,327
S										
S	22	DISTRIBUTION RATE OF RETURN (PRESENT)	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%
S	23	DISTRIBUTION INDEX RATE OF RETURN (PRESENT)	0.00	1.08	1.06	1.08	1.09	1.10	0.55	1.08
S										
S	24	**DEVELOPMENT OF PURCHASED POWER RETURN**								
S	25	Purchased Electric Revenues	0	0	0	0	0	0	0	0
S	26	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	27	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	28	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	29	Purchased Power Operating Income	0	0	0	0	0	0	0	0
S	30	Rate Base - Purchased Pwr Cash Working Capital	0	0	0	0	0	0	0	0
S	31	PURCHASED POWER RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	32	**DEVELOPMENT OF TRANSMISSON RETURN**								
S	33	Transmission Revenues	0	0	0	0	0	0	0	0
S	34	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	35	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	36	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	37	Transmission Operating Income	0	0	0	0	0	0	0	0
S	38	Rate Base - Transmission Cash Working Capital	0	0	0	0	0	0	0	0
S	39	TRANSMISSION RATE OF RETURN (PRESENT)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S										
S	40	TOTAL OPERATING INCOME (RETURN)	0	0	99	422	521	6	(384)	665
S	41	TOTAL RATE BASE	0	0	1,692	7,187	8,883	103	(6,537)	11,327
S	42	COMPOSITE RATE OF RETURN AT CURRENT RATES	0.00%	0.00%	5.87%	5.87%	5.87%	5.87%	0.00%	5.87%
S										
S										
S	43	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	44	**DEVELOPMENT OF DISTRIBUTION RETURN AT EQUALIZED RATE**								
S	45	RATE BASE	0	0	1,692	7,187	8,883	103	(6,537)	11,327
S	46	RETURN (= RATE BASE * 8.08% ROR)	0	0	137	581	718	8	(528)	915
S	47	PLUS:								
S	48	OPERATING EXPENSES								
S	49	Operation and Maintenance Expense	0	0	35	742	5,610	494	32	6,914

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
S	50	Depreciation and Amortization Expense	0	46,065	5,256	40,255	9,156	418	1,662	102,812
S	51	Taxes Other Than Income Taxes-General	0	2,697	174	391	3,132	160	563	7,117
S	52	Taxes Other Than Income Taxes-Distribution GRT	0	17,859	1,226	3,589	9,783	2,234	1,095	35,785
S	53	State and Federal Income Taxes	0	18,848	641	(363)	3,431	234	102	22,893
S	54	TOTAL OPERATING EXPENSES	0	189,972	10,846	56,257	157,595	38,360	22,270	475,301
S										
S	55	EQUALS TOTAL COST OF SERVICE	0	316,911	22,140	63,797	172,060	39,316	23,303	637,528
S	56	LESS:								
S	57	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	58	Other Operating Revenue	0	7,758	949	1,454	2,049	461	4,269	16,938
S	59	EQUALS:								
S	60	DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR	0	309,153	21,191	62,344	170,012	38,855	19,034	620,590
S	61	Distribution Cost Increase without Forfeited Discount	0	57,647	5,129	3,424	6,569	434	469	73,673
S	62	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE	(0)	57,847	5,147	3,436	6,592	436	471	73,928
S	63	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUN	0.00%	22.92%	31.93%	5.81%	4.02%	1.13%	2.53%	13.47%
S			0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**								
S	65	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	66	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	67	PLUS:								
S	68	OPERATING EXPENSES								
S	69	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	72	EQUALS TOTAL PURCHASED POWER COST OF SERVICE	0	0	0	0	0	0	0	0
S	73	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	74	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**								
S	76	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	77	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	78	PLUS:								
S	79	OPERATING EXPENSES								
S	80	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	81	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	82	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	83	EQUALS TOTAL TRANSMISSION COST OF SERVICE	0	0	0	0	0	0	0	0
S	84	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	85	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**	(0)	57,847	5,147	3,436	6,592	436	471	73,928
S										
S										
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**								
S	89	RATE BASE	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
S	90	RETURN (= RATE BASE * 8.08% ROR)	0	126,939	11,294	7,540	14,465	956	1,032	162,227
S	91	PLUS:								
S	92	OPERATING EXPENSES								
S	93	Operation and Maintenance Expense	0	104,503	3,550	12,386	132,093	35,314	18,849	306,694
S	94	Depreciation and Amortization Expense	0	46,065	5,256	40,255	9,156	418	1,662	102,812
S	95	Taxes Other Than Income Taxes-General	0	2,697	174	391	3,132	160	563	7,117
S	96	Taxes Other Than Income Taxes-GRT	0	17,859	1,226	3,589	9,783	2,234	1,095	35,785
S	97	State and Federal Income Taxes	0	18,848	641	(363)	3,431	234	102	22,893
S	98	TOTAL OPERATING EXPENSES	0	189,972	10,846	56,257	157,595	38,360	22,270	475,301
S										
S	99	EQUALS TOTAL COST OF SERVICE	0	316,911	22,140	63,797	172,060	39,316	23,303	637,528
S	100	LESS:								

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
S	50	Depreciation and Amortization Expense	0	7,183	820	6,523	1,443	65	259	16,294
S	51	Taxes Other Than Income Taxes-General	0	421	27	63	494	25	88	1,117
S	52	Taxes Other Than Income Taxes-Distribution GRT	0	2,787	191	582	1,542	349	161	5,613
S	53	State and Federal Income Taxes	0	2,929	99	(59)	542	37	(15)	3,533
S	54	TOTAL OPERATING EXPENSES	0	29,615	1,685	9,158	24,949	6,016	3,443	74,866
S										
S	55	EQUALS TOTAL COST OF SERVICE	0	49,372	3,442	10,381	27,233	6,167	3,488	100,082
S	56	LESS:								
S	57	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	58	Other Operating Revenue	0	1,200	145	248	360	82	669	2,705
S	59	EQUALS:								
S	60	DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR	0	48,172	3,297	10,133	26,873	6,085	2,818	97,377
S	61	Distribution Cost Increase without Forfeited Discount	0	16,688	1,484	1,033	1,929	128	37	21,300
S	62	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE	(0)	16,746	1,490	1,036	1,936	128	37	21,374
S	63	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUN	0.00%	53.01%	81.91%	11.35%	7.73%	2.15%	1.34%	28.00%
S			0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**								
S	65	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	66	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	67	PLUS:								
S	68	OPERATING EXPENSES								
S	69	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	72	EQUALS TOTAL PURCHASED POWER COST OF SERVICE	0	0	0	0	0	0	0	0
S	73	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	74	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**								
S	76	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	77	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	78	PLUS:								
S	79	OPERATING EXPENSES								
S	80	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	81	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	82	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	83	EQUALS TOTAL TRANSMISSION COST OF SERVICE	0	0	0	0	0	0	0	0
S	84	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	85	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**	(0)	16,746	1,490	1,036	1,936	128	37	21,374
S										
S										
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**								
S	89	RATE BASE	0	244,511	21,750	15,132	28,267	1,873	547	312,079
S	90	RETURN (= RATE BASE * 8.08% ROR)	0	19,757	1,757	1,223	2,284	151	44	25,216
S	91	PLUS:								
S	92	OPERATING EXPENSES								
S	93	Operation and Maintenance Expense	0	16,295	548	2,048	20,929	5,540	2,950	48,309
S	94	Depreciation and Amortization Expense	0	7,183	820	6,523	1,443	65	259	16,294
S	95	Taxes Other Than Income Taxes-General	0	421	27	63	494	25	88	1,117
S	96	Taxes Other Than Income Taxes-GRT	0	2,787	191	582	1,542	349	161	5,613
S	97	State and Federal Income Taxes	0	2,929	99	(59)	542	37	(15)	3,533
S	98	TOTAL OPERATING EXPENSES	0	29,615	1,685	9,158	24,949	6,016	3,443	74,866
S										
S	99	EQUALS TOTAL COST OF SERVICE	0	49,372	3,442	10,381	27,233	6,167	3,488	100,082
S	100	LESS:								

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
S	50	Depreciation and Amortization Expense	0	5,312	3,515	10,187	859	22	192	20,087
S	51	Taxes Other Than Income Taxes-General	0	311	116	99	294	9	63	892
S	52	Taxes Other Than Income Taxes-Distribution GRT	0	2,076	825	915	929	143	(73)	4,815
S	53	State and Federal Income Taxes	0	2,226	447	(69)	346	17	(642)	2,325
S	54	TOTAL OPERATING EXPENSES	0	21,434	7,072	13,980	14,590	2,404	1,608	61,088
S										
S	55	EQUALS TOTAL COST OF SERVICE	0	36,281	14,696	15,977	16,039	2,471	(775)	84,688
S	56	LESS:								
S	57	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	58	Other Operating Revenue	0	722	570	277	99	14	462	2,145
S	59	EQUALS:								
S	60	DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR	0	35,559	14,126	15,699	15,940	2,457	(1,238)	82,543
S	61	Distribution Cost Increase without Forfeited Discount	0	5,543	2,846	746	541	25	(890)	8,811
S	62	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE	(0)	5,562	2,856	748	543	25	(893)	8,841
S	63	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUN	0.00%	18.47%	25.23%	4.99%	3.51%	1.04%	0.00%	11.95%
S			0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**								
S	65	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	66	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	67	PLUS:								
S	68	OPERATING EXPENSES								
S	69	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	72	EQUALS TOTAL PURCHASED POWER COST OF SERVICE	0	0	0	0	0	0	0	0
S	73	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	74	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**								
S	76	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	77	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	78	PLUS:								
S	79	OPERATING EXPENSES								
S	80	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	81	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	82	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	83	EQUALS TOTAL TRANSMISSION COST OF SERVICE	0	0	0	0	0	0	0	0
S	84	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	85	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**	(0)	5,562	2,856	748	543	25	(893)	8,841
S										
S										
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**								
S	89	RATE BASE	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
S	90	RETURN (= RATE BASE * 8.08% ROR)	0	14,846	7,624	1,997	1,449	67	(2,383)	23,601
S	91	PLUS:								
S	92	OPERATING EXPENSES								
S	93	Operation and Maintenance Expense	0	11,509	2,169	2,847	12,163	2,213	2,068	32,969
S	94	Depreciation and Amortization Expense	0	5,312	3,515	10,187	859	22	192	20,087
S	95	Taxes Other Than Income Taxes-General	0	311	116	99	294	9	63	892
S	96	Taxes Other Than Income Taxes-GRT	0	2,076	825	915	929	143	(73)	4,815
S	97	State and Federal Income Taxes	0	2,226	447	(69)	346	17	(642)	2,325
S	98	TOTAL OPERATING EXPENSES	0	21,434	7,072	13,980	14,590	2,404	1,608	61,088
S										
S	99	EQUALS TOTAL COST OF SERVICE	0	36,281	14,696	15,977	16,039	2,471	(775)	84,688
S	100	LESS:								

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
S	50	Depreciation and Amortization Expense	0	0	8	233	51	0	0	293
S	51	Taxes Other Than Income Taxes-General	0	0	0	2	17	0	0	20
S	52	Taxes Other Than Income Taxes-Distribution GRT	0	0	2	21	54	1	(1)	76
S	53	State and Federal Income Taxes	0	0	1	(2)	20	0	(5)	14
S	54	TOTAL OPERATING EXPENSES	0	0	16	314	831	16	(1)	1,176
S										
S	55	EQUALS TOTAL COST OF SERVICE	0	0	35	358	914	16	(19)	1,304
S	56	LESS:								
S	57	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	58	Other Operating Revenue	0	0	1	4	1	0	1	8
S	59	EQUALS:								
S	60	DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR	0	0	33	354	913	16	(20)	1,297
S	61	Distribution Cost Increase without Forfeited Discount	0	0	5	13	24	0	(5)	36
S	62	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE	(0)	(0)	5	13	24	0	(5)	37
S	63	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUN	0.00%	0.00%	18.26%	3.72%	2.67%	0.43%	0.00%	2.89%
S			0.00%	0.00%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**								
S	65	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	66	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	67	PLUS:								
S	68	OPERATING EXPENSES								
S	69	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	72	EQUALS TOTAL PURCHASED POWER COST OF SERVICE	0	0	0	0	0	0	0	0
S	73	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	74	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**								
S	76	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	77	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	78	PLUS:								
S	79	OPERATING EXPENSES								
S	80	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	81	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	82	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	83	EQUALS TOTAL TRANSMISSION COST OF SERVICE	0	0	0	0	0	0	0	0
S	84	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	85	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**	(0)	(0)	5	13	24	0	(5)	37
S										
S										
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**								
S	89	RATE BASE	0	0	225	555	1,036	3	(226)	1,593
S	90	RETURN (= RATE BASE * 8.08% ROR)	0	0	18	45	84	0	(18)	129
S	91	PLUS:								
S	92	OPERATING EXPENSES								
S	93	Operation and Maintenance Expense	0	0	5	59	688	15	5	772
S	94	Depreciation and Amortization Expense	0	0	8	233	51	0	0	293
S	95	Taxes Other Than Income Taxes-General	0	0	0	2	17	0	0	20
S	96	Taxes Other Than Income Taxes-GRT	0	0	2	21	54	1	(1)	76
S	97	State and Federal Income Taxes	0	0	1	(2)	20	0	(5)	14
S	98	TOTAL OPERATING EXPENSES	0	0	16	314	831	16	(1)	1,176
S										
S	99	EQUALS TOTAL COST OF SERVICE	0	0	35	358	914	16	(19)	1,304
S	100	LESS:								

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
S	50	Depreciation and Amortization Expense	0	0	63	2,911	417	0	3	3,395
S	51	Taxes Other Than Income Taxes-General	0	0	2	28	143	0	1	174
S	52	Taxes Other Than Income Taxes-Distribution GRT	0	0	15	262	442	32	(40)	710
S	53	State and Federal Income Taxes	0	0	8	(17)	172	2	(138)	27
S	54	TOTAL OPERATING EXPENSES	0	0	123	3,927	6,783	529	(142)	11,220
S										
S	55	EQUALS TOTAL COST OF SERVICE	0	0	260	4,507	7,501	537	(670)	12,135
S	56	LESS:								
S	57	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	58	Other Operating Revenue	0	0	9	57	8	0	7	82
S	59	EQUALS:								
S	60	DISTRIBUTION BASE RATE SALES AT 8.08% EQUALIZED ROR	0	0	251	4,451	7,493	537	(678)	12,053
S	61	Distribution Cost Increase without Forfeited Discount	0	0	55	233	287	3	(212)	367
S	62	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE	(0)	(0)	55	233	288	3	(212)	368
S	63	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISCOUN	0.00%	0.00%	27.93%	5.51%	3.99%	0.62%	0.00%	3.14%
S			0.00%	0.00%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
S	64	**DEVELOPMENT OF PURCH. POWER RETURN AT EQUALIZED RATE**								
S	65	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	66	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	67	PLUS:								
S	68	OPERATING EXPENSES								
S	69	Purchased Power O&M Expense	0	0	0	0	0	0	0	0
S	70	Purchased Power Income Taxes	0	0	0	0	0	0	0	0
S	71	Purchased Power GRT Expense	0	0	0	0	0	0	0	0
S	72	EQUALS TOTAL PURCHASED POWER COST OF SERVICE	0	0	0	0	0	0	0	0
S	73	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	74	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	75	**DEVELOPMENT OF TRANSMISSION RETURN AT EQUALIZED RATE**								
S	76	RATE BASE (CWC)	0	0	0	0	0	0	0	0
S	77	RETURN (= RATE BASE * 8.08% ROR)	0	0	0	0	0	0	0	0
S	78	PLUS:								
S	79	OPERATING EXPENSES								
S	80	Transmission O&M Expense	0	0	0	0	0	0	0	0
S	81	Transmission Income Taxes	0	0	0	0	0	0	0	0
S	82	Transmission GRT Expense	0	0	0	0	0	0	0	0
S	83	EQUALS TOTAL TRANSMISSION COST OF SERVICE	0	0	0	0	0	0	0	0
S	84	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE	0	0	0	0	0	0	0	0
S	85	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**TOTAL INCREASE (DECREASE) REQUIRED**	(0)	(0)	55	233	288	3	(212)	368
S										
S										
S	87	**EQUALIZED RETURN AT 8.08% PROPOSED ROR**								
S	88	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**								
S	89	RATE BASE	0	0	1,692	7,187	8,883	103	(6,537)	11,327
S	90	RETURN (= RATE BASE * 8.08% ROR)	0	0	137	581	718	8	(528)	915
S	91	PLUS:								
S	92	OPERATING EXPENSES								
S	93	Operation and Maintenance Expense	0	0	35	742	5,610	494	32	6,914
S	94	Depreciation and Amortization Expense	0	0	63	2,911	417	0	3	3,395
S	95	Taxes Other Than Income Taxes-General	0	0	2	28	143	0	1	174
S	96	Taxes Other Than Income Taxes-GRT	0	0	15	262	442	32	(40)	710
S	97	State and Federal Income Taxes	0	0	8	(17)	172	2	(138)	27
S	98	TOTAL OPERATING EXPENSES	0	0	123	3,927	6,783	529	(142)	11,220
S										
S	99	EQUALS TOTAL COST OF SERVICE	0	0	260	4,507	7,501	537	(670)	12,135
S	100	LESS:								

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
S	101	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	102	Other Operating Revenue	0	7,758	949	1,454	2,049	461	4,269	16,938
S	103	EQUALS:								
S	104	OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR	0	309,153	21,191	62,344	170,012	38,855	19,034	620,590
S	105	COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUN	(0)	57,647	5,129	3,424	6,569	434	469	73,673
S	106	TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE	(0)	57,847	5,147	3,436	6,592	436	471	73,928
S			0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
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RBP	1	**DEVELOPMENT OF RATE BASE**								
RBP	2	**ELECTRIC PLANT IN SERVICE**								
RBP	3	INTANGIBLE PLANT								
RBP	4	302-303-Franchise and consents & Misc Intang. Plant	0	19	3	3	0	0	0	25
RBP	5	303-AMI Plant	0	0	0	4,627	0	0	0	4,627
RBP	6	TOTAL INTANGIBLE PLANT	0	19	3	4,631	0	0	0	4,653
RBP										
RBP	7	TRANSMISSION PLANT								
RBP	8	350-359 Accounts	0	0	0	0	0	0	0	0
RBP	9	361- Transmission Related Plant	0	0	0	0	0	0	0	0
RBP	10	TOTAL TRANSMISSION PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	11	DISTRIBUTION PLANT								
RBP	12	360-Land & Land Rights	0	0	0	0	0	0	0	0
RBP	13	361-Structures & Improvements	0	0	0	0	0	0	0	0
RBP	14	362-Station Equipment	0	0	0	0	0	0	0	0
RBP	15	363-Computer HW SW and Equipment								
RBP	16	363.1 Computer Hardware	0	0	0	0	0	0	0	0
RBP	17	363.2 Computer Software	0	0	0	0	0	0	0	0
RBP	18	363.3 Communication Equipment	0	0	0	0	0	0	0	0
RBP	19	Total Account 363	0	0	0	0	0	0	0	0
RBP	20	364-Poles,Towers & Fixtures								
RBP	21	Primary HT	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
S	101	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	102	Other Operating Revenue	0	1,200	145	248	360	82	669	2,705
S	103	EQUALS:								
S	104	OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR	0	48,172	3,297	10,133	26,873	6,085	2,818	97,377
S	105	COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUN	(0)	16,688	1,484	1,033	1,929	128	37	21,300
S	106	TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE	(0)	16,746	1,490	1,036	1,936	128	37	21,374
S			0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
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RBP	1	**DEVELOPMENT OF RATE BASE**								
RBP	2	**ELECTRIC PLANT IN SERVICE**								
RBP	3	INTANGIBLE PLANT								
RBP	4	302-303-Franchise and consents & Misc Intang. Plant	0	3	0	0	0	0	0	4
RBP	5	303-AMI Plant	0	0	0	750	0	0	0	750
RBP	6	TOTAL INTANGIBLE PLANT	0	3	0	750	0	0	0	754
RBP										
RBP	7	TRANSMISSION PLANT								
RBP	8	350-359 Accounts	0	0	0	0	0	0	0	0
RBP	9	361- Transmission Related Plant	0	0	0	0	0	0	0	0
RBP	10	TOTAL TRANSMISSION PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	11	DISTRIBUTION PLANT								
RBP	12	360-Land & Land Rights	0	0	0	0	0	0	0	0
RBP	13	361-Structures & Improvements	0	0	0	0	0	0	0	0
RBP	14	362-Station Equipment	0	0	0	0	0	0	0	0
RBP	15	363-Computer HW SW and Equipment								
RBP	16	363.1 Computer Hardware	0	0	0	0	0	0	0	0
RBP	17	363.2 Computer Software	0	0	0	0	0	0	0	0
RBP	18	363.3 Communication Equipment	0	0	0	0	0	0	0	0
RBP	19	Total Account 363	0	0	0	0	0	0	0	0
RBP	20	364-Poles,Towers & Fixtures								
RBP	21	Primary HT	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
S	101	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	102	Other Operating Revenue	0	722	570	277	99	14	462	2,145
S	103	EQUALS:								
S	104	OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR	0	35,559	14,126	15,699	15,940	2,457	(1,238)	82,543
S	105	COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUN	(0)	5,543	2,846	746	541	25	(890)	8,811
S	106	TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE	(0)	5,562	2,856	748	543	25	(893)	8,841
S			0.00%	8.08%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
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RBP	1	**DEVELOPMENT OF RATE BASE**								
RBP	2	**ELECTRIC PLANT IN SERVICE**								
RBP	3	INTANGIBLE PLANT								
RBP	4	302-303-Franchise and consents & Misc Intang. Plant	0	2	2	1	0	0	0	5
RBP	5	303-AMI Plant	0	0	0	1,171	0	0	0	1,171
RBP	6	TOTAL INTANGIBLE PLANT	0	2	2	1,172	0	0	0	1,176
RBP										
RBP	7	TRANSMISSION PLANT								
RBP	8	350-359 Accounts	0	0	0	0	0	0	0	0
RBP	9	361- Transmission Related Plant	0	0	0	0	0	0	0	0
RBP	10	TOTAL TRANSMISSION PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	11	DISTRIBUTION PLANT								
RBP	12	360-Land & Land Rights	0	0	0	0	0	0	0	0
RBP	13	361-Structures & Improvements	0	0	0	0	0	0	0	0
RBP	14	362-Station Equipment	0	0	0	0	0	0	0	0
RBP	15	363-Computer HW SW and Equipment								
RBP	16	363.1 Computer Hardware	0	0	0	0	0	0	0	0
RBP	17	363.2 Computer Software	0	0	0	0	0	0	0	0
RBP	18	363.3 Communication Equipment	0	0	0	0	0	0	0	0
RBP	19	Total Account 363	0	0	0	0	0	0	0	0
RBP	20	364-Poles,Towers & Fixtures								
RBP	21	Primary HT	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
S	101	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	102	Other Operating Revenue	0	0	1	4	1	0	1	8
S	103	EQUALS:								
S	104	OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR	0	0	33	354	913	16	(20)	1,297
S	105	COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUN	(0)	(0)	5	13	24	0	(5)	36
S	106	TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE	(0)	(0)	5	13	24	0	(5)	37
S			0.00%	0.00%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
S										
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Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
S	101	Decommissioning Revenues	0	0	0	0	0	0	0	0
S	102	Other Operating Revenue	0	0	9	57	8	0	7	82
S	103	EQUALS:								
S	104	OVERALL TOTAL COST OF SERVICE AT 8.08% EQUALIZED ROR	0	0	251	4,451	7,493	537	(678)	12,053
S	105	COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISCOUN	(0)	(0)	55	233	287	3	(212)	367
S	106	TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE	(0)	(0)	55	233	288	3	(212)	368
S			0.00%	0.00%	8.08%	8.08%	8.08%	8.08%	0.00%	8.08%
S										
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Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBP	22	Primary	0	0	0	0	0	0	0	0
RBP	23	Secondary	0	406,708	0	0	0	0	0	406,708
RBP	24	Total Account 364	0	406,708	0	0	0	0	0	406,708
RBP	25	365-Overhead Conductors & Devices								
RBP	26	Primary HT	0	0	0	0	0	0	0	0
RBP	27	Primary	0	0	0	0	0	0	0	0
RBP	28	Secondary	0	576,690	0	0	0	0	0	576,690
RBP	29	Total Account 365	0	576,690	0	0	0	0	0	576,690
RBP	30	366-Underground Conduit								
RBP	31	Primary HT	0	0	0	0	0	0	0	0
RBP	32	Primary	0	0	0	0	0	0	0	0
RBP	33	Secondary	0	250,133	0	0	0	0	0	250,133
RBP	34	Total Account 366	0	250,133	0	0	0	0	0	250,133
RBP	35	367-Underground Conductors & Devices								
RBP	36	Primary HT	0	0	0	0	0	0	0	0
RBP	37	Primary	0	0	0	0	0	0	0	0
RBP	38	Secondary	0	487,451	0	0	0	0	0	487,451
RBP	39	Total Account 367	0	487,451	0	0	0	0	0	487,451
RBP	40	368-Line Transformers	0	0	0	0	0	0	0	0
RBP	41	369-Services	0	0	281,055	0	0	0	0	281,055
RBP	42	370-Meters	0	0	0	276,443	0	0	0	276,443
RBP	43	371-Installation on Customer Premises	0	0	0	0	0	0	12,731	12,731
RBP	44	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBP	45	374-Asset Retirement Costs for Distribution Plant	0	549	90	88	0	0	4	731
RBP	46	SUBTOTAL DISTRIBUTION PLANT	0	1,721,531	281,144	276,531	0	0	12,735	2,291,942
RBP										
RBP	47	ENERGY STORAGE PLANT								
RBP	48	387 [Reserved]	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)	0	1,721,531	281,144	276,531	0	0	12,735	2,291,942
RBP										
RBP										
RBP										
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**								
RBP										
RBP	64	GENERAL PLANT								
RBP	65	389-Land and Land Rights	0	105	2	14	187	9	34	349
RBP	66	390-Structures and Improvements	0	7,370	120	959	13,140	600	2,361	24,551
RBP	67	391-Office Furniture & Equipment	0	928	15	121	1,654	76	297	3,091
RBP	68	393-Store Equipment	0	4	0	1	8	0	1	14
RBP	69	394-Tools, Shop & Garage Equip.	0	7,241	118	942	12,909	589	2,320	24,119
RBP	70	395-Laboratory Equipment	0	10	0	1	17	1	3	32
RBP	71	397 Communication Equipment								
RBP	72	397.1 Computer Hardware	0	775	13	101	1,381	63	248	2,580
RBP	73	397.2 Computer Software	0	2,686	44	350	4,789	219	861	8,948

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBP	22	Primary	0	0	0	0	0	0	0	0
RBP	23	Secondary	0	63,423	0	0	0	0	0	63,423
RBP	24	Total Account 364	0	63,423	0	0	0	0	0	63,423
RBP	25	365-Overhead Conductors & Devices								
RBP	26	Primary HT	0	0	0	0	0	0	0	0
RBP	27	Primary	0	0	0	0	0	0	0	0
RBP	28	Secondary	0	89,931	0	0	0	0	0	89,931
RBP	29	Total Account 365	0	89,931	0	0	0	0	0	89,931
RBP	30	366-Underground Conduit								
RBP	31	Primary HT	0	0	0	0	0	0	0	0
RBP	32	Primary	0	0	0	0	0	0	0	0
RBP	33	Secondary	0	39,006	0	0	0	0	0	39,006
RBP	34	Total Account 366	0	39,006	0	0	0	0	0	39,006
RBP	35	367-Underground Conductors & Devices								
RBP	36	Primary HT	0	0	0	0	0	0	0	0
RBP	37	Primary	0	0	0	0	0	0	0	0
RBP	38	Secondary	0	76,014	0	0	0	0	0	76,014
RBP	39	Total Account 367	0	76,014	0	0	0	0	0	76,014
RBP	40	368-Line Transformers	0	0	0	0	0	0	0	0
RBP	41	369-Services	0	0	43,828	0	0	0	0	43,828
RBP	42	370-Meters	0	0	0	44,799	0	0	0	44,799
RBP	43	371-Installation on Customer Premises	0	0	0	0	0	0	1,985	1,985
RBP	44	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBP	45	374-Asset Retirement Costs for Distribution Plant	0	86	14	14	0	0	1	114
RBP	46	SUBTOTAL DISTRIBUTION PLANT	0	268,460	43,842	44,813	0	0	1,986	359,102
RBP										
RBP	47	ENERGY STORAGE PLANT								
RBP	48	387 [Reserved]	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)	0	268,460	43,842	44,813	0	0	1,986	359,102
RBP										
RBP										
RBP										
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**								
RBP										
RBP	64	GENERAL PLANT								
RBP	65	389-Land and Land Rights	0	16	0	2	29	1	5	55
RBP	66	390-Structures and Improvements	0	1,149	19	155	2,070	94	368	3,856
RBP	67	391-Office Furniture & Equipment	0	145	2	20	261	12	46	485
RBP	68	393-Store Equipment	0	1	0	0	1	0	0	2
RBP	69	394-Tools, Shop & Garage Equip.	0	1,129	18	153	2,034	92	362	3,788
RBP	70	395-Laboratory Equipment	0	1	0	0	3	0	0	5
RBP	71	397 Communication Equipment								
RBP	72	397.1 Computer Hardware	0	121	2	16	218	10	39	405
RBP	73	397.2 Computer Software	0	419	7	57	755	34	134	1,405

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBP	22	Primary	0	0	0	0	0	0	0	0
RBP	23	Secondary	0	46,960	0	0	0	0	0	46,960
RBP	24	Total Account 364	0	46,960	0	0	0	0	0	46,960
RBP	25	365-Overhead Conductors & Devices								
RBP	26	Primary HT	0	0	0	0	0	0	0	0
RBP	27	Primary	0	0	0	0	0	0	0	0
RBP	28	Secondary	0	66,586	0	0	0	0	0	66,586
RBP	29	Total Account 365	0	66,586	0	0	0	0	0	66,586
RBP	30	366-Underground Conduit								
RBP	31	Primary HT	0	0	0	0	0	0	0	0
RBP	32	Primary	0	0	0	0	0	0	0	0
RBP	33	Secondary	0	28,881	0	0	0	0	0	28,881
RBP	34	Total Account 366	0	28,881	0	0	0	0	0	28,881
RBP	35	367-Underground Conductors & Devices								
RBP	36	Primary HT	0	0	0	0	0	0	0	0
RBP	37	Primary	0	0	0	0	0	0	0	0
RBP	38	Secondary	0	56,283	0	0	0	0	0	56,283
RBP	39	Total Account 367	0	56,283	0	0	0	0	0	56,283
RBP	40	368-Line Transformers	0	0	0	0	0	0	0	0
RBP	41	369-Services	0	0	187,976	0	0	0	0	187,976
RBP	42	370-Meters	0	0	0	69,960	0	0	0	69,960
RBP	43	371-Installation on Customer Premises	0	0	0	0	0	0	1,470	1,470
RBP	44	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBP	45	374-Asset Retirement Costs for Distribution Plant	0	63	60	22	0	0	0	146
RBP	46	SUBTOTAL DISTRIBUTION PLANT	0	198,773	188,036	69,982	0	0	1,470	458,261
RBP										
RBP	47	ENERGY STORAGE PLANT								
RBP	48	387 [Reserved]	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)	0	198,773	188,036	69,982	0	0	1,470	458,261
RBP										
RBP										
RBP										
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**								
RBP										
RBP	64	GENERAL PLANT								
RBP	65	389-Land and Land Rights	0	12	1	3	18	0	4	39
RBP	66	390-Structures and Improvements	0	851	80	243	1,232	31	273	2,711
RBP	67	391-Office Furniture & Equipment	0	107	10	31	155	4	34	341
RBP	68	393-Store Equipment	0	0	0	0	1	0	0	2
RBP	69	394-Tools, Shop & Garage Equip.	0	836	79	239	1,211	31	268	2,663
RBP	70	395-Laboratory Equipment	0	1	0	0	2	0	0	4
RBP	71	397 Communication Equipment								
RBP	72	397.1 Computer Hardware	0	89	8	26	130	3	29	285
RBP	73	397.2 Computer Software	0	310	29	88	449	11	99	988

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBP	22	Primary	0	0	0	0	0	0	0	0
RBP	23	Secondary	0	0	0	0	0	0	0	0
RBP	24	Total Account 364	0	0	0	0	0	0	0	0
RBP	25	365-Overhead Conductors & Devices								
RBP	26	Primary HT	0	0	0	0	0	0	0	0
RBP	27	Primary	0	0	0	0	0	0	0	0
RBP	28	Secondary	0	0	0	0	0	0	0	0
RBP	29	Total Account 365	0	0	0	0	0	0	0	0
RBP	30	366-Underground Conduit								
RBP	31	Primary HT	0	0	0	0	0	0	0	0
RBP	32	Primary	0	0	0	0	0	0	0	0
RBP	33	Secondary	0	0	0	0	0	0	0	0
RBP	34	Total Account 366	0	0	0	0	0	0	0	0
RBP	35	367-Underground Conductors & Devices								
RBP	36	Primary HT	0	0	0	0	0	0	0	0
RBP	37	Primary	0	0	0	0	0	0	0	0
RBP	38	Secondary	0	0	0	0	0	0	0	0
RBP	39	Total Account 367	0	0	0	0	0	0	0	0
RBP	40	368-Line Transformers	0	0	0	0	0	0	0	0
RBP	41	369-Services	0	0	450	0	0	0	0	450
RBP	42	370-Meters	0	0	0	1,600	0	0	0	1,600
RBP	43	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
RBP	44	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBP	45	374-Asset Retirement Costs for Distribution Plant	0	0	0	1	0	0	0	1
RBP	46	SUBTOTAL DISTRIBUTION PLANT	0	0	451	1,601	0	0	0	2,051
RBP										
RBP	47	ENERGY STORAGE PLANT								
RBP	48	387 [Reserved]	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)	0	0	451	1,601	0	0	0	2,051
RBP										
RBP										
RBP										
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**								
RBP										
RBP	64	GENERAL PLANT								
RBP	65	389-Land and Land Rights	0	0	0	0	1	0	0	1
RBP	66	390-Structures and Improvements	0	0	0	6	73	0	1	80
RBP	67	391-Office Furniture & Equipment	0	0	0	1	9	0	0	10
RBP	68	393-Store Equipment	0	0	0	0	0	0	0	0
RBP	69	394-Tools, Shop & Garage Equip.	0	0	0	5	72	0	1	79
RBP	70	395-Laboratory Equipment	0	0	0	0	0	0	0	0
RBP	71	397 Communication Equipment								
RBP	72	397.1 Computer Hardware	0	0	0	1	8	0	0	8
RBP	73	397.2 Computer Software	0	0	0	2	27	0	0	29

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBP	22	Primary	0	0	0	0	0	0	0	0
RBP	23	Secondary	0	0	0	0	0	0	0	0
RBP	24	Total Account 364	0	0	0	0	0	0	0	0
RBP	25	365-Overhead Conductors & Devices								
RBP	26	Primary HT	0	0	0	0	0	0	0	0
RBP	27	Primary	0	0	0	0	0	0	0	0
RBP	28	Secondary	0	0	0	0	0	0	0	0
RBP	29	Total Account 365	0	0	0	0	0	0	0	0
RBP	30	366-Underground Conduit								
RBP	31	Primary HT	0	0	0	0	0	0	0	0
RBP	32	Primary	0	0	0	0	0	0	0	0
RBP	33	Secondary	0	0	0	0	0	0	0	0
RBP	34	Total Account 366	0	0	0	0	0	0	0	0
RBP	35	367-Underground Conductors & Devices								
RBP	36	Primary HT	0	0	0	0	0	0	0	0
RBP	37	Primary	0	0	0	0	0	0	0	0
RBP	38	Secondary	0	0	0	0	0	0	0	0
RBP	39	Total Account 367	0	0	0	0	0	0	0	0
RBP	40	368-Line Transformers	0	0	0	0	0	0	0	0
RBP	41	369-Services	0	0	3,361	0	0	0	0	3,361
RBP	42	370-Meters	0	0	0	19,993	0	0	0	19,993
RBP	43	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
RBP	44	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBP	45	374-Asset Retirement Costs for Distribution Plant	0	0	1	6	0	0	0	7
RBP	46	SUBTOTAL DISTRIBUTION PLANT	0	0	3,362	20,000	0	0	0	23,362
RBP										
RBP	47	ENERGY STORAGE PLANT								
RBP	48	387 [Reserved]	0	0	0	0	0	0	0	0
RBP	49	387.1 Land and Land Rights	0	0	0	0	0	0	0	0
RBP	50	387.2 Structures and Improvements	0	0	0	0	0	0	0	0
RBP	51	387.3 Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	52	387.4 [Reserved]	0	0	0	0	0	0	0	0
RBP	53	387.5 Collector Systems	0	0	0	0	0	0	0	0
RBP	54	387.6 Generator Step-Up Transformers (GSU)	0	0	0	0	0	0	0	0
RBP	55	387.7 Inverters	0	0	0	0	0	0	0	0
RBP	56	387.8 Computer Hardware	0	0	0	0	0	0	0	0
RBP	57	387.9 Computer Software	0	0	0	0	0	0	0	0
RBP	58	387.10 Communication Equipment	0	0	0	0	0	0	0	0
RBP	59	387.11 Miscellaneous Energy Storage Equipment	0	0	0	0	0	0	0	0
RBP	60	387.12 Asset Retirement Costs for Energy Storage	0	0	0	0	0	0	0	0
RBP	61	TOTAL ENERGY STORAGE PLANT	0	0	0	0	0	0	0	0
RBP										
RBP	62	TOTAL DISTRIBUTION PLANT (INCLUDING STORAGE)	0	0	3,362	20,000	0	0	0	23,362
RBP										
RBP										
RBP										
RBP	63	**ELECTRIC PLANT IN SERVICE CONTINUED**								
RBP										
RBP	64	GENERAL PLANT								
RBP	65	389-Land and Land Rights	0	0	0	1	9	0	0	10
RBP	66	390-Structures and Improvements	0	0	1	69	598	1	5	675
RBP	67	391-Office Furniture & Equipment	0	0	0	9	75	0	1	85
RBP	68	393-Store Equipment	0	0	0	0	0	0	0	0
RBP	69	394-Tools, Shop & Garage Equip.	0	0	1	68	588	1	5	663
RBP	70	395-Laboratory Equipment	0	0	0	0	1	0	0	1
RBP	71	397 Communication Equipment								
RBP	72	397.1 Computer Hardware	0	0	0	7	63	0	1	71
RBP	73	397.2 Computer Software	0	0	1	25	218	0	2	246

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBP	74	397.3 Communication Equipment	0	4,385	71	571	7,818	357	1,405	14,607
RBP	75	Total Account 397	0	7,846	128	1,021	13,988	638	2,513	26,135
RBP	76	398-Miscellaneous Equipment / ARO	0	197	3	26	352	16	63	657
RBP	77	399-Other Tangible Property	0	214	3	28	382	17	69	713
RBP	78	TOTAL GENERAL PLANT	0	23,914	389	3,113	42,637	1,946	7,661	79,661
RBP										
RBP										
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**	0	1,745,464	281,537	284,274	42,637	1,946	20,397	2,376,256
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RBD	1	**LESS: ACCUMULATED DEPRECIATION**								
RBD										
RBD	2	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	3	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	4	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION								
RBD	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
RBD	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
RBD	7	362-Station Equipment	0	0	0	0	0	0	0	0
RBD	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
RBD	9	364-Poles,Towers & Fixtures	0	(619)	0	0	0	0	0	(619)
RBD	10	365-Overhead Conductors & Devices	0	69,333	0	0	0	0	0	69,333
RBD	11	366-Underground Conduit	0	41,371	0	0	0	0	0	41,371
RBD	12	367-Underground Conductors & Devices	0	27,282	0	0	0	0	0	27,282
RBD	13	368-Line Transformers	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBP	74	397.3 Communication Equipment	0	684	11	92	1,232	56	219	2,294
RBP	75	Total Account 397	0	1,223	20	165	2,204	100	392	4,104
RBP	76	398-Miscellaneous Equipment / ARO	0	31	1	4	55	3	10	103
RBP	77	399-Other Tangible Property	0	33	1	5	60	3	11	112
RBP	78	TOTAL GENERAL PLANT	0	3,729	61	504	6,718	303	1,195	12,510
RBP										
RBP										
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**	0	272,192	43,904	46,068	6,718	303	3,181	372,366
RBP										
RBP										
RBP									

			General Service							
Sch.	LineNo.	Description	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBP	74	397.3 Communication Equipment	0	506	48	144	733	19	162	1,613
RBP	75	Total Account 397	0	906	85	258	1,312	33	290	2,885
RBP	76	398-Miscellaneous Equipment / ARO	0	23	2	6	33	1	7	73
RBP	77	399-Other Tangible Property	0	25	2	7	36	1	8	79
RBP	78	TOTAL GENERAL PLANT	0	2,761	260	788	3,999	102	885	8,795
RBP										
RBP										
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**	0	201,536	188,298	71,942	3,999	102	2,355	468,232
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RBD	1	**LESS: ACCUMULATED DEPRECIATION**								
RBD										
RBD	2	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	3	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	4	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION								
RBD	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
RBD	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
RBD	7	362-Station Equipment	0	0	0	0	0	0	0	0
RBD	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
RBD	9	364-Poles,Towers & Fixtures	0	(71)	0	0	0	0	0	(71)
RBD	10	365-Overhead Conductors & Devices	0	8,005	0	0	0	0	0	8,005
RBD	11	366-Underground Conduit	0	4,777	0	0	0	0	0	4,777
RBD	12	367-Underground Conductors & Devices	0	3,150	0	0	0	0	0	3,150
RBD	13	368-Line Transformers	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBP	74	397.3 Communication Equipment	0	0	0	3	44	0	0	48
RBP	75	Total Account 397	0	0	0	6	78	0	1	85
RBP	76	398-Miscellaneous Equipment / ARO	0	0	0	0	2	0	0	2
RBP	77	399-Other Tangible Property	0	0	0	0	2	0	0	2
RBP	78	TOTAL GENERAL PLANT	0	0	1	18	238	0	2	259
RBP										
RBP										
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**	0	0	451	1,646	238	0	2	2,338
RBP										
RBP										
RBP									

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBP	74	397.3 Communication Equipment	0	0	1	41	356	0	3	401
RBP	75	Total Account 397	0	0	2	74	637	1	5	718
RBP	76	398-Miscellaneous Equipment / ARO	0	0	0	2	16	0	0	18
RBP	77	399-Other Tangible Property	0	0	0	2	17	0	0	20
RBP	78	TOTAL GENERAL PLANT	0	0	5	225	1,942	2	16	2,189
RBP										
RBP										
RBP	79	**TOTAL ELECTRIC PLANT IN SERVICE**	0	0	3,367	20,560	1,942	2	16	25,886
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RBD	1	**LESS: ACCUMULATED DEPRECIATION**								
RBD										
RBD	2	INTANGIBLE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	3	TRANSMISSION PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	4	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION								
RBD	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
RBD	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
RBD	7	362-Station Equipment	0	0	0	0	0	0	0	0
RBD	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
RBD	9	364-Poles,Towers & Fixtures	0	0	0	0	0	0	0	0
RBD	10	365-Overhead Conductors & Devices	0	0	0	0	0	0	0	0
RBD	11	366-Underground Conduit	0	0	0	0	0	0	0	0
RBD	12	367-Underground Conductors & Devices	0	0	0	0	0	0	0	0
RBD	13	368-Line Transformers	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBD	14	369-Services	0	0	123,580	0	0	0	0	123,580
RBD	15	370-Meters	0	0	0	183,743	0	0	0	183,743
RBD	16	371-Installation on Customer Premises	0	0	0	0	0	0	9,069	9,069
RBD	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBD	18	374-Asset Retirement Costs for Distribution Plant	0	376	61	60	0	0	3	500
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION	0	137,743	123,641	183,803	0	0	9,071	454,258
RBD										
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	0	10,066	164	1,310	17,946	819	3,225	33,530
RBD										
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**	0	147,808	123,805	185,113	17,946	819	12,296	487,788
RBD										
RBD										
RBD										
RBD	23	**NET ELECTRIC PLANT IN SERVICE**	0	1,597,656	157,732	99,161	24,691	1,127	8,101	1,888,468
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RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
RBO										
RBO	2	**PLUS: ADDITIONS TO RATE BASE**								
RBO										
RBO	3	COMMON PLANT	0	69,927	1,139	9,102	124,674	5,691	22,403	232,935
RBO	4	Pension Assets / (Liability)	0	18,181	296	2,366	32,415	1,480	5,825	60,563
RBO										
RBO	5	**WORKING CAPITAL**								
RBO	6	Purchased Power Cash Working Capital	0	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital	0	0	0	0	0	0	0	0
RBO	8	Distribution								
RBO	9	Cash Working Capital	0	21,276	922	4,361	18,644	4,512	3,159	52,874
RBO	10	Materials and Supplies	0	7,044	1,136	1,147	172	8	82	9,590
RBO	11	Total Distribution Working Capital	0	28,321	2,058	5,508	18,816	4,520	3,241	62,464
RBO	12	TOTAL WORKING CAPITAL	0	28,321	2,058	5,508	18,816	4,520	3,241	62,464
RBO	13	TOTAL ADDITIONS TO RATE BASE	0	116,429	3,493	16,977	175,906	11,691	31,468	355,962
RBO										
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**								
RBO	15	Customer Deposits	0	0	0	0	0	0	21,953	21,953
RBO	16	Customer Advances for Construction	0	2,077	0	0	0	0	0	2,077
RBO	17	Deferred Income Taxes and Credits								

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBD	14	369-Services	0	0	19,271	0	0	0	0	19,271
RBD	15	370-Meters	0	0	0	29,776	0	0	0	29,776
RBD	16	371-Installation on Customer Premises	0	0	0	0	0	0	1,414	1,414
RBD	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBD	18	374-Asset Retirement Costs for Distribution Plant	0	59	10	10	0	0	0	78
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION	0	21,480	19,281	29,786	0	0	1,415	71,962
RBD										
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	0	1,570	26	212	2,827	128	503	5,266
RBD										
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**	0	23,050	19,307	29,998	2,827	128	1,917	77,227
RBD										
RBD										
RBD										
RBD	23	**NET ELECTRIC PLANT IN SERVICE**	0	249,143	24,597	16,070	3,890	176	1,263	295,139
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RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
RBO										
RBO	2	**PLUS: ADDITIONS TO RATE BASE**								
RBO										
RBO	3	COMMON PLANT	0	10,905	178	1,475	19,643	887	3,494	36,581
RBO	4	Pension Assets / (Liability)	0	2,835	46	383	5,107	231	908	9,511
RBO										
RBO	5	**WORKING CAPITAL**								
RBO	6	Purchased Power Cash Working Capital	0	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital	0	0	0	0	0	0	0	0
RBO	8	Distribution								
RBO	9	Cash Working Capital	0	2,839	96	716	2,998	731	498	7,878
RBO	10	Materials and Supplies	0	1,098	177	186	27	1	13	1,503
RBO	11	Total Distribution Working Capital	0	3,938	273	902	3,025	732	510	9,381
RBO	12	TOTAL WORKING CAPITAL	0	3,938	273	902	3,025	732	510	9,381
RBO	13	TOTAL ADDITIONS TO RATE BASE	0	17,678	497	2,761	27,775	1,851	4,912	55,473
RBO										
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**								
RBO	15	Customer Deposits	0	0	0	0	0	0	4,874	4,874
RBO	16	Customer Advances for Construction	0	324	0	0	0	0	0	324
RBO	17	Deferred Income Taxes and Credits								

Sch.	LineNo.	Description	General Service							
			CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBD	14	369-Services	0	0	82,653	0	0	0	0	82,653
RBD	15	370-Meters	0	0	0	46,500	0	0	0	46,500
RBD	16	371-Installation on Customer Premises	0	0	0	0	0	0	1,047	1,047
RBD	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBD	18	374-Asset Retirement Costs for Distribution Plant	0	43	41	15	0	0	0	100
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION	0	15,904	82,694	46,515	0	0	1,047	146,161
RBD										
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	0	1,162	110	332	1,683	43	372	3,702
RBD										
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**	0	17,066	82,804	46,847	1,683	43	1,420	149,863
RBD										
RBD										
RBD										
RBD	23	**NET ELECTRIC PLANT IN SERVICE**	0	184,470	105,494	25,095	2,316	59	935	318,369
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RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
RBO										
RBO	2	**PLUS: ADDITIONS TO RATE BASE**								
RBO										
RBO	3	COMMON PLANT	0	8,074	762	2,303	11,693	298	2,587	25,717
RBO	4	Pension Assets / (Liability)	0	2,099	198	599	3,040	77	673	6,686
RBO										
RBO	5	**WORKING CAPITAL**								
RBO	6	Purchased Power Cash Working Capital	0	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital	0	0	0	0	0	0	0	0
RBO	8	Distribution								
RBO	9	Cash Working Capital	0	4,740	1,489	2,205	2,887	451	138	11,910
RBO	10	Materials and Supplies	0	813	760	290	16	0	10	1,890
RBO	11	Total Distribution Working Capital	0	5,553	2,249	2,495	2,903	452	148	13,800
RBO	12	TOTAL WORKING CAPITAL	0	5,553	2,249	2,495	2,903	452	148	13,800
RBO	13	TOTAL ADDITIONS TO RATE BASE	0	15,727	3,208	5,397	17,637	827	3,407	46,203
RBO										
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**								
RBO	15	Customer Deposits	0	0	0	0	0	0	33,280	33,280
RBO	16	Customer Advances for Construction	0	240	0	0	0	0	0	240
RBO	17	Deferred Income Taxes and Credits								

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBD	14	369-Services	0	0	198	0	0	0	0	198
RBD	15	370-Meters	0	0	0	1,064	0	0	0	1,064
RBD	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
RBD	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBD	18	374-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION	0	0	198	1,064	0	0	0	1,262
RBD										
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	0	0	0	8	100	0	1	109
RBD										
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**	0	0	198	1,072	100	0	1	1,371
RBD										
RBD										
RBD										
RBD	23	**NET ELECTRIC PLANT IN SERVICE**	0	0	253	574	138	0	1	966
RBD										
RBD										
RBD										
RBD										
RBD										
RBD										
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RBD										
RBD										
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RBD										
RBD										
RBD										
RBD										
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
RBO										
RBO	2	**PLUS: ADDITIONS TO RATE BASE**								
RBO										
RBO	3	COMMON PLANT	0	0	2	53	697	1	6	758
RBO	4	Pension Assets / (Liability)	0	0	0	14	181	0	2	197
RBO										
RBO	5	**WORKING CAPITAL**								
RBO	6	Purchased Power Cash Working Capital	0	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital	0	0	0	0	0	0	0	0
RBO	8	Distribution								
RBO	9	Cash Working Capital	0	0	3	40	139	2	(1)	182
RBO	10	Materials and Supplies	0	0	2	7	1	0	0	9
RBO	11	Total Distribution Working Capital	0	0	5	46	140	2	(1)	192
RBO	12	TOTAL WORKING CAPITAL	0	0	5	46	140	2	(1)	192
RBO	13	TOTAL ADDITIONS TO RATE BASE	0	0	7	113	1,018	3	6	1,147
RBO										
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**								
RBO	15	Customer Deposits	0	0	0	0	0	0	232	232
RBO	16	Customer Advances for Construction	0	0	0	0	0	0	0	0
RBO	17	Deferred Income Taxes and Credits								

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBD	14	369-Services	0	0	1,478	0	0	0	0	1,478
RBD	15	370-Meters	0	0	0	13,289	0	0	0	13,289
RBD	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
RBD	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
RBD	18	374-Asset Retirement Costs for Distribution Plant	0	0	1	4	0	0	0	5
RBD	19	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION	0	0	1,479	13,293	0	0	0	14,772
RBD										
RBD	20	ENERGY STORAGE PLANT ACCUMULATED DEPRECIATION	0	0	0	0	0	0	0	0
RBD										
RBD	21	GENERAL PLANT ACCUMULATED DEPRECIATION	0	0	2	95	817	1	7	922
RBD										
RBD	22	**TOTAL ACCUMULATED DEPRECIATION**	0	0	1,480	13,388	817	1	7	15,693
RBD										
RBD										
RBD										
RBD	23	**NET ELECTRIC PLANT IN SERVICE**	0	0	1,886	7,172	1,125	1	9	10,193
RBD										
RBD										
RBD										
RBD										
RBD										
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RBD										
RBD										
RBD										
RBD										
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**								
RBO										
RBO	2	**PLUS: ADDITIONS TO RATE BASE**								
RBO										
RBO	3	COMMON PLANT	0	0	14	658	5,678	5	46	6,402
RBO	4	Pension Assets / (Liability)	0	0	4	171	1,476	1	12	1,664
RBO										
RBO	5	**WORKING CAPITAL**								
RBO	6	Purchased Power Cash Working Capital	0	0	0	0	0	0	0	0
RBO	7	Transmission Cash Working Capital	0	0	0	0	0	0	0	0
RBO	8	Distribution								
RBO	9	Cash Working Capital	0	0	32	753	1,578	96	(83)	2,376
RBO	10	Materials and Supplies	0	0	14	83	8	0	0	104
RBO	11	Total Distribution Working Capital	0	0	45	836	1,586	96	(83)	2,480
RBO	12	TOTAL WORKING CAPITAL	0	0	45	836	1,586	96	(83)	2,480
RBO	13	TOTAL ADDITIONS TO RATE BASE	0	0	63	1,666	8,741	103	(25)	10,547
RBO										
RBO	14	**LESS: DEDUCTIONS TO RATE BASE**								
RBO	15	Customer Deposits	0	0	0	0	0	0	6,514	6,514
RBO	16	Customer Advances for Construction	0	0	0	0	0	0	0	0
RBO	17	Deferred Income Taxes and Credits								

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBO	18	Plant	0	133,580	21,546	21,755	3,263	149	1,561	181,854
RBO	19	Common Plant	0	10,292	168	1,340	18,349	838	3,297	34,282
RBO	20	Corporate Alternative Minimum Tax	0	(1,675)	(270)	(273)	(41)	(2)	(20)	(2,280)
RBO	21	Unamortized AMR Investment	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	0	(1,774)	0	0	0	0	0	(1,774)
RBO	23	Unamortized Payment for BESS	0	560	0	0	0	0	0	560
RBO	24	Total Deferred Income Taxes and Credits	0	140,423	21,443	22,822	21,571	985	4,839	212,082
RBO	25	TOTAL DEDUCTIONS TO RATE BASE	0	143,059	21,443	22,822	21,571	985	26,791	236,672
RBO										
RBO										
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE	0	116,429	3,493	16,977	175,906	11,691	31,468	355,962
RBO										
RBO	27	TOTAL PURCHASED POWER RATE BASE	0	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE	0	0	0	0	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
RBO										
RBO	30	**TOTAL RATE BASE**	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
RBO										
RBO										
RBO										
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RBO										
RBO										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**								
RBC	2	**DISTRIBUTION**								
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	4	Payroll (Distribution Only)	0	21,110	344	2,748	37,638	1,718	6,763	70,321
RBC	5	Pension	0	337	5	44	601	27	108	1,122
RBC	6	Other Expenses	0	66,914	2,605	7,729	74,486	28,251	9,246	189,230
RBC	7	TOTAL EXPENSES	0	88,361	2,955	10,520	112,725	29,997	16,117	260,674
RBC	8	POR Working Capital	0	72,945	4,659	17,089	47,404	11,143	5,385	158,624
RBC	9	TOTAL EXPENSES PER DAY	0	442	21	76	439	113	59	1,149
RBC										
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	9,721	459	1,664	9,650	2,479	1,296	25,269
RBC										
RBC	11	AVERAGE PREPAYMENTS	0	699	36	105	579	59	938	2,416
RBC	12	DISTRIBUTION ACCRUED TAXES	0	13,841	908	3,079	8,488	1,977	960	29,253
RBC	13	INTEREST PAYMENTS	0	(2,984)	(481)	(486)	(73)	(3)	(35)	(4,063)
RBC										
RBC										
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIREMENT	0	21,276	922	4,361	18,644	4,512	3,159	52,874
RBC										
RBC										
RBC	15	**PURCHASED POWER**								
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	17	Commodity Purchased - Contract Purchases	0	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	0	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES	0	0	0	0	0	0	0	0
RBC										
RBC	20	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBO	18	Plant	0	20,831	3,360	3,526	514	23	243	28,497
RBO	19	Common Plant	0	1,605	26	217	2,891	131	514	5,384
RBO	20	Corporate Alternative Minimum Tax	0	(261)	(42)	(44)	(6)	(0)	(3)	(357)
RBO	21	Unamortized AMR Investment	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	0	(277)	0	0	0	0	0	(277)
RBO	23	Unamortized Payment for BESS	0	87	0	0	0	0	0	87
RBO	24	Total Deferred Income Taxes and Credits	0	21,898	3,344	3,698	3,399	154	755	33,247
RBO	25	TOTAL DEDUCTIONS TO RATE BASE	0	22,309	3,344	3,698	3,399	154	5,629	38,532
RBO										
RBO										
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE	0	17,678	497	2,761	27,775	1,851	4,912	55,473
RBO										
RBO	27	TOTAL PURCHASED POWER RATE BASE	0	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE	0	0	0	0	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE	0	244,511	21,750	15,132	28,267	1,873	547	312,079
RBO										
RBO	30	**TOTAL RATE BASE**	0	244,511	21,750	15,132	28,267	1,873	547	312,079
RBO										
RBO										
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RBO										
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RBO										
RBO										
RBO										
RBO										
RBO										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**								
RBC	2	**DISTRIBUTION**								
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	4	Payroll (Distribution Only)	0	3,292	54	445	5,930	268	1,055	11,044
RBC	5	Pension	0	53	1	7	95	4	17	176
RBC	6	Other Expenses	0	10,337	393	1,281	11,824	4,433	1,451	29,718
RBC	7	TOTAL EXPENSES	0	13,681	447	1,734	17,848	4,705	2,523	40,938
RBC	8	POR Working Capital	0	11,675	672	3,375	9,250	2,209	1,031	28,213
RBC	9	TOTAL EXPENSES PER DAY	0	69	3	14	74	19	10	189
RBC										
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	1,528	67	308	1,633	417	214	4,167
RBC										
RBC	11	AVERAGE PREPAYMENTS	0	109	6	17	91	9	146	378
RBC	12	DISTRIBUTION ACCRUED TAXES	0	1,668	98	470	1,285	306	143	3,970
RBC	13	INTEREST PAYMENTS	0	(465)	(75)	(79)	(11)	(1)	(5)	(637)
RBC										
RBC										
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIREMENT	0	2,839	96	716	2,998	731	498	7,878
RBC										
RBC										
RBC	15	**PURCHASED POWER**								
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	17	Commodity Purchased - Contract Purchases	0	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	0	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES	0	0	0	0	0	0	0	0
RBC										
RBC	20	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBO	18	Plant	0	15,423	14,410	5,506	306	8	180	35,834
RBO	19	Common Plant	0	1,188	112	339	1,721	44	381	3,785
RBO	20	Corporate Alternative Minimum Tax	0	(193)	(181)	(69)	(4)	(0)	(2)	(449)
RBO	21	Unamortized AMR Investment	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	0	(205)	0	0	0	0	0	(205)
RBO	23	Unamortized Payment for BESS	0	0	0	0	0	0	0	0
RBO	24	Total Deferred Income Taxes and Credits	0	16,214	14,342	5,776	2,023	52	559	38,964
RBO	25	TOTAL DEDUCTIONS TO RATE BASE	0	16,453	14,342	5,776	2,023	52	33,839	72,484
RBO										
RBO										
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE	0	15,727	3,208	5,397	17,637	827	3,407	46,203
RBO										
RBO	27	TOTAL PURCHASED POWER RATE BASE	0	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE	0	0	0	0	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
RBO										
RBO	30	**TOTAL RATE BASE**	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
RBO										
RBO										
RBO										
RBO										
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RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**								
RBC	2	**DISTRIBUTION**								
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	4	Payroll (Distribution Only)	0	2,437	230	695	3,530	90	781	7,764
RBC	5	Pension	0	39	4	11	56	1	12	124
RBC	6	Other Expenses	0	7,267	1,576	1,713	6,795	1,563	987	19,901
RBC	7	TOTAL EXPENSES	0	9,744	1,809	2,420	10,381	1,654	1,781	27,789
RBC	8	POR Working Capital	0	45,679	17,165	22,757	23,434	3,700	(529)	112,206
RBC	9	TOTAL EXPENSES PER DAY	0	152	52	69	93	15	3	384
RBC										
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	3,340	1,143	1,517	2,038	323	75	8,437
RBC										
RBC	11	AVERAGE PREPAYMENTS	0	81	24	26	54	4	105	294
RBC	12	DISTRIBUTION ACCRUED TAXES	0	1,664	643	784	802	125	(38)	3,981
RBC	13	INTEREST PAYMENTS	0	(345)	(322)	(123)	(7)	(0)	(4)	(801)
RBC										
RBC										
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIREMENT	0	4,740	1,489	2,205	2,887	451	138	11,910
RBC										
RBC										
RBC	15	**PURCHASED POWER**								
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	17	Commodity Purchased - Contract Purchases	0	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	0	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES	0	0	0	0	0	0	0	0
RBC										
RBC	20	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBO	18	Plant	0	0	35	126	18	0	0	179
RBO	19	Common Plant	0	0	0	8	103	0	1	112
RBO	20	Corporate Alternative Minimum Tax	0	0	(0)	(2)	(0)	(0)	(0)	(2)
RBO	21	Unamortized AMR Investment	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	0	0	0	0	0	0	0	0
RBO	23	Unamortized Payment for BESS	0	0	0	0	0	0	0	0
RBO	24	Total Deferred Income Taxes and Credits	0	0	34	132	121	0	1	288
RBO	25	TOTAL DEDUCTIONS TO RATE BASE	0	0	34	132	121	0	233	521
RBO										
RBO										
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE	0	0	7	113	1,018	3	6	1,147
RBO										
RBO	27	TOTAL PURCHASED POWER RATE BASE	0	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE	0	0	0	0	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE	0	0	225	555	1,036	3	(226)	1,593
RBO										
RBO	30	**TOTAL RATE BASE**	0	0	225	555	1,036	3	(226)	1,593
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**								
RBC	2	**DISTRIBUTION**								
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	4	Payroll (Distribution Only)	0	0	1	16	210	0	2	229
RBC	5	Pension	0	0	0	0	3	0	0	4
RBC	6	Other Expenses	0	0	3	34	374	4	2	418
RBC	7	TOTAL EXPENSES	0	0	4	50	588	4	4	650
RBC	8	POR Working Capital	0	0	29	347	904	16	(15)	1,280
RBC	9	TOTAL EXPENSES PER DAY	0	0	0	1	4	0	(0)	5
RBC										
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	2	24	90	1	(1)	116
RBC										
RBC	11	AVERAGE PREPAYMENTS	0	0	0	1	3	0	0	4
RBC	12	DISTRIBUTION ACCRUED TAXES	0	0	2	18	46	1	(1)	66
RBC	13	INTEREST PAYMENTS	0	0	(1)	(3)	(0)	(0)	(0)	(4)
RBC										
RBC										
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIREMENT	0	0	3	40	139	2	(1)	182
RBC										
RBC										
RBC	15	**PURCHASED POWER**								
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	17	Commodity Purchased - Contract Purchases	0	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	0	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES	0	0	0	0	0	0	0	0
RBC										
RBC	20	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBO	18	Plant	0	0	258	1,573	149	0	1	1,981
RBO	19	Common Plant	0	0	2	97	836	1	7	942
RBO	20	Corporate Alternative Minimum Tax	0	0	(3)	(20)	(2)	(0)	(0)	(25)
RBO	21	Unamortized AMR Investment	0	0	0	0	0	0	0	0
RBO	22	Contributions in Aid of Construction (CIAC)	0	0	0	0	0	0	0	0
RBO	23	Unamortized Payment for BESS	0	0	0	0	0	0	0	0
RBO	24	Total Deferred Income Taxes and Credits	0	0	256	1,651	982	1	8	2,898
RBO	25	TOTAL DEDUCTIONS TO RATE BASE	0	0	256	1,651	982	1	6,522	9,412
RBO										
RBO										
RBO	26	TOTAL DISTRIBUTION ADDITIONS TO RATE BASE	0	0	63	1,666	8,741	103	(25)	10,547
RBO										
RBO	27	TOTAL PURCHASED POWER RATE BASE	0	0	0	0	0	0	0	0
RBO	28	TOTAL TRANSMSSION RATE BASE	0	0	0	0	0	0	0	0
RBO	29	TOTAL DISTRIBUTION RATE BASE	0	0	1,692	7,187	8,883	103	(6,537)	11,327
RBO										
RBO	30	**TOTAL RATE BASE**	0	0	1,692	7,187	8,883	103	(6,537)	11,327
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBO										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG)**								
RBC	2	**DISTRIBUTION**								
RBC	3	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	4	Payroll (Distribution Only)	0	0	4	199	1,714	2	14	1,933
RBC	5	Pension	0	0	0	3	27	0	0	31
RBC	6	Other Expenses	0	0	25	428	3,048	29	16	3,546
RBC	7	TOTAL EXPENSES	0	0	29	630	4,790	30	30	5,510
RBC	8	POR Working Capital	0	0	402	8,657	14,787	1,095	(957)	23,985
RBC	9	TOTAL EXPENSES PER DAY	0	0	1	25	54	3	(3)	81
RBC										
RBC	10	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	26	560	1,180	68	(56)	1,777
RBC										
RBC	11	AVERAGE PREPAYMENTS	0	0	0	8	26	1	1	36
RBC	12	DISTRIBUTION ACCRUED TAXES	0	0	11	221	375	27	(28)	607
RBC	13	INTEREST PAYMENTS	0	0	(6)	(35)	(3)	(0)	(0)	(44)
RBC										
RBC										
RBC	14	NET DISTRIBUTION CASH WORKING CAPITAL REQUIREMENT	0	0	32	753	1,578	96	(83)	2,376
RBC										
RBC										
RBC	15	**PURCHASED POWER**								
RBC	16	O&M EXPENSE RELATED CASH WORKING CAPITAL								
RBC	17	Commodity Purchased - Contract Purchases	0	0	0	0	0	0	0	0
RBC	18	Commodity Purchased - Spot Market Purchases	0	0	0	0	0	0	0	0
RBC	19	TOTAL EXPENSES	0	0	0	0	0	0	0	0
RBC										
RBC	20	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBC										
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	22	Energy ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC	24	**TRANSMISSION**								
RBC	25	O&M EXPENSE - PJM Transmission Purchase	0	0	0	0	0	0	0	0
RBC										
RBC	26	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0
RBC										
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	28	TRANSMISSION ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC										
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT	0	21,276	922	4,361	18,644	4,512	3,159	52,874
RBC										
RBC										
RBC										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**								
RBC										
RBC	2	**LAG/LEAD DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**
RBC	3	REVENUE LAG DAYS								
RBC	4	EXPENSE LAG DAYS	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59
RBC	5	PURCHASED POWER REVENUE LAG DAYS								
RBC	6	PURCHASED POWER EXP LAG DAYS	21.99	21.99	21.99	21.99	21.99	21.99	21.99	21.99
RBC	7	TRANSMISSION REVENUE LAG DAYS								
RBC	8	TRANSMISSION EXP LAG DAYS	45.10	45.10	45.10	45.10	45.10	45.10	45.10	45.10
RBC	9	DISTRIBUTION REVENUE LAG DAYS								
RBC	10	DISTRIBUTION LAG DAYS	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00
RBC										
RBC										
RBC										
RBC										
RBC	11	DISTRIBUTION ACCRUED TAXES								
RBC	12	Federal Income Tax	0	230,991	16,364	7,729	31,507	2,111	1,673	290,375
RBC	13	State Income Tax	0	41,024	2,906	1,373	5,596	375	297	51,570
RBC	14	PURTA Taxes	0	0	0	0	0	0	0	0
RBC	15	Capital Stock	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	0	72,222	11,649	11,762	1,764	81	844	98,323
RBC	18	PA Corp Loan Tax	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	0	4,707,650	300,653	1,102,850	3,059,296	719,159	347,503	10,237,110
RBC	22	Lag Day Weighted Accrued Taxes	0	5,051,886	331,572	1,123,713	3,098,163	721,726	350,317	10,677,378
RBC	23	TOTAL ACCRUED TAXES CWC	0	13,841	908	3,079	8,488	1,977	960	29,253
RBC										
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS								
RBC	25	Customer Experience	0	0	0	0	0	0	135	135
RBC	26	EEI, EAP and EPRI Dues	0	38	3	8	21	5	2	76
RBC	27	PUC Assess - Electric	0	286	20	58	157	36	18	575
RBC	28	Prepaid Rents and Pole Attachment Fees	0	88	0	0	0	0	0	88
RBC	29	Land Leasing	0	7	1	1	0	0	0	9

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBC										
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	22	Energy ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC	24	**TRANSMISSION**								
RBC	25	O&M EXPENSE - PJM Transmission Purchase	0	0	0	0	0	0	0	0
RBC										
RBC	26	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0
RBC										
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	28	TRANSMISSION ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC										
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT	0	2,839	96	716	2,998	731	498	7,878
RBC										
RBC										
RBC										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**								
RBC										
RBC	2	**LAG/LEAD DAYS**								
RBC	3	REVENUE LAG DAYS								
RBC	4	EXPENSE LAG DAYS								
RBC	5	PURCHASED POWER REVENUE LAG DAYS								
RBC	6	PURCHASED POWER EXP LAG DAYS								
RBC	7	TRANSMISSION REVENUE LAG DAYS								
RBC	8	TRANSMISSION EXP LAG DAYS								
RBC	9	DISTRIBUTION REVENUE LAG DAYS								
RBC	10	DISTRIBUTION LAG DAYS								
RBC										
RBC										
RBC										
RBC										
RBC	11	DISTRIBUTION ACCRUED TAXES								
RBC	12	Federal Income Tax	0	6,942	(36)	(540)	1,624	112	(70)	8,032
RBC	13	State Income Tax	0	1,233	(6)	(96)	288	20	(12)	1,426
RBC	14	PURTA Taxes	0	0	0	0	0	0	0	0
RBC	15	Capital Stock	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	0	11,263	1,817	1,906	278	13	132	15,407
RBC	18	PA Corp Loan Tax	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	0	589,298	33,922	170,339	466,887	111,502	52,057	1,424,005
RBC	22	Lag Day Weighted Accrued Taxes	0	608,735	35,696	171,610	469,077	111,647	52,106	1,448,871
RBC	23	TOTAL ACCRUED TAXES CWC	0	1,668	98	470	1,285	306	143	3,970
RBC										
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS								
RBC	25	Customer Experience	0	0	0	0	0	0	21	21
RBC	26	EEI, EAP and EPRI Dues	0	6	0	1	3	1	0	12
RBC	27	PUC Assess - Electric	0	45	3	9	25	6	3	90
RBC	28	Prepaid Rents and Pole Attachment Fees	0	14	0	0	0	0	0	14
RBC	29	Land Leasing	0	1	0	0	0	0	0	1

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBC										
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	22	Energy ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC	24	**TRANSMISSION**								
RBC	25	O&M EXPENSE - PJM Transmission Purchase	0	0	0	0	0	0	0	0
RBC										
RBC	26	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0
RBC										
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	28	TRANSMISSION ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC										
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT	0	4,740	1,489	2,205	2,887	451	138	11,910
RBC										
RBC										
RBC										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**								
RBC										
RBC	2	**LAG/LEAD DAYS**								
RBC	3	REVENUE LAG DAYS								
RBC	4	EXPENSE LAG DAYS								
RBC	5	PURCHASED POWER REVENUE LAG DAYS								
RBC	6	PURCHASED POWER EXP LAG DAYS								
RBC	7	TRANSMISSION REVENUE LAG DAYS								
RBC	8	TRANSMISSION EXP LAG DAYS								
RBC	9	DISTRIBUTION REVENUE LAG DAYS								
RBC	10	DISTRIBUTION LAG DAYS								
RBC										
RBC										
RBC										
RBC										
RBC	11	DISTRIBUTION ACCRUED TAXES								
RBC	12	Federal Income Tax	0	31,610	13,420	2,765	3,604	171	(6,226)	45,344
RBC	13	State Income Tax	0	5,614	2,383	491	640	30	(1,106)	8,053
RBC	14	PURTA Taxes	0	0	0	0	0	0	0	0
RBC	15	Capital Stock	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	0	8,339	7,791	2,977	165	4	97	19,374
RBC	18	PA Corp Loan Tax	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	0	561,847	211,131	279,903	288,230	45,512	(6,510)	1,380,114
RBC	22	Lag Day Weighted Accrued Taxes	0	607,410	234,726	286,135	292,640	45,717	(13,744)	1,452,885
RBC	23	TOTAL ACCRUED TAXES CWC	0	1,664	643	784	802	125	(38)	3,981
RBC										
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS								
RBC	25	Customer Experience	0	0	0	0	0	0	16	16
RBC	26	EEI, EAP and EPRI Dues	0	4	2	2	2	0	(0)	10
RBC	27	PUC Assess - Electric	0	33	13	15	15	2	(1)	76
RBC	28	Prepaid Rents and Pole Attachment Fees	0	10	0	0	0	0	0	10
RBC	29	Land Leasing	0	1	1	0	0	0	0	2

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBC										
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	22	Energy ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC	24	**TRANSMISSION**								
RBC	25	O&M EXPENSE - PJM Transmission Purchase	0	0	0	0	0	0	0	0
RBC										
RBC	26	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0
RBC										
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	28	TRANSMISSION ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC										
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT	0	0	3	40	139	2	(1)	182
RBC										
RBC										
RBC										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**								
RBC										
RBC	2	**LAG/LEAD DAYS**								
RBC	3	REVENUE LAG DAYS								
RBC	4	EXPENSE LAG DAYS								
RBC	5	PURCHASED POWER REVENUE LAG DAYS								
RBC	6	PURCHASED POWER EXP LAG DAYS								
RBC	7	TRANSMISSION REVENUE LAG DAYS								
RBC	8	TRANSMISSION EXP LAG DAYS								
RBC	9	DISTRIBUTION REVENUE LAG DAYS								
RBC	10	DISTRIBUTION LAG DAYS								
RBC										
RBC										
RBC										
RBC										
RBC	11	DISTRIBUTION ACCRUED TAXES								
RBC	12	Federal Income Tax	0	0	38	76	236	1	(53)	298
RBC	13	State Income Tax	0	0	7	14	42	0	(9)	53
RBC	14	PURTA Taxes	0	0	0	0	0	0	0	0
RBC	15	Capital Stock	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	0	0	19	68	10	0	0	97
RBC	18	PA Corp Loan Tax	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	0	0	529	6,386	16,653	296	(275)	23,589
RBC	22	Lag Day Weighted Accrued Taxes	0	0	593	6,544	16,941	297	(337)	24,037
RBC	23	TOTAL ACCRUED TAXES CWC	0	0	2	18	46	1	(1)	66
RBC										
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS								
RBC	25	Customer Experience	0	0	0	0	0	0	0	0
RBC	26	EEI, EAP and EPRI Dues	0	0	0	0	0	0	(0)	0
RBC	27	PUC Assess - Electric	0	0	0	0	1	0	(0)	1
RBC	28	Prepaid Rents and Pole Attachment Fees	0	0	0	0	0	0	0	0
RBC	29	Land Leasing	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBC										
RBC	21	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	22	Energy ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	23	NET Energy CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC	24	**TRANSMISSION**								
RBC	25	O&M EXPENSE - PJM Transmission Purchase	0	0	0	0	0	0	0	0
RBC										
RBC	26	TOTAL EXPENSES PER DAY	0	0	0	0	0	0	0	0
RBC										
RBC	27	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)	0	0	0	0	0	0	0	0
RBC										
RBC	28	TRANSMISSION ACCRUED TAXES	0	0	0	0	0	0	0	0
RBC										
RBC	29	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT	0	0	0	0	0	0	0	0
RBC										
RBC										
RBC	30	NET TOTAL CASH WORKING CAPITAL REQUIREMENT	0	0	32	753	1,578	96	(83)	2,376
RBC										
RBC										
RBC										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**								
RBC										
RBC	2	**LAG/LEAD DAYS**								
RBC	3	REVENUE LAG DAYS								
RBC	4	EXPENSE LAG DAYS								
RBC	5	PURCHASED POWER REVENUE LAG DAYS								
RBC	6	PURCHASED POWER EXP LAG DAYS								
RBC	7	TRANSMISSION REVENUE LAG DAYS								
RBC	8	TRANSMISSION EXP LAG DAYS								
RBC	9	DISTRIBUTION REVENUE LAG DAYS								
RBC	10	DISTRIBUTION LAG DAYS								
RBC										
RBC										
RBC										
RBC										
RBC	11	DISTRIBUTION ACCRUED TAXES								
RBC	12	Federal Income Tax	0	0	227	756	1,714	20	(1,309)	1,409
RBC	13	State Income Tax	0	0	40	134	304	4	(233)	250
RBC	14	PURTA Taxes	0	0	0	0	0	0	0	0
RBC	15	Capital Stock	0	0	0	0	0	0	0	0
RBC	16	PA & Local Use Taxes	0	0	0	0	0	0	0	0
RBC	17	PA Property tax	0	0	139	851	80	0	1	1,071
RBC	18	PA Corp Loan Tax	0	0	0	0	0	0	0	0
RBC	19	Philadelphia BPT	0	0	0	0	0	0	0	0
RBC	20	Local Privilege Tax	0	0	0	0	0	0	0	0
RBC	21	Gross Receipts Tax	0	0	3,670	78,954	134,865	9,989	(8,726)	218,753
RBC	22	Lag Day Weighted Accrued Taxes	0	0	4,077	80,696	136,964	10,014	(10,267)	221,483
RBC	23	TOTAL ACCRUED TAXES CWC	0	0	11	221	375	27	(28)	607
RBC										
RBC	24	DISTRIBUTION AVERAGE PREPAYMENTS								
RBC	25	Customer Experience	0	0	0	0	0	0	0	0
RBC	26	EEI, EAP and EPRI Dues	0	0	0	1	1	0	(0)	1
RBC	27	PUC Assess - Electric	0	0	0	4	7	0	(1)	11
RBC	28	Prepaid Rents and Pole Attachment Fees	0	0	0	0	0	0	0	0
RBC	29	Land Leasing	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBC	30	Equipment Maintenance	0	11	2	2	0	0	0	14
RBC	31	Business Support System	0	0	0	0	0	0	361	361
RBC	32	VEBA Adjustment	0	186	3	24	332	15	60	620
RBC	33	Facilities Contracts	0	5	1	1	0	0	0	6
RBC	34	IT Service Contracts	0	40	7	7	1	0	0	55
RBC	35	Fleet Activities	0	38	1	5	68	3	12	127
RBC	36	Postage	0	0	0	0	0	0	350	350
RBC	37	TOTAL AVERAGE PREPAYMENTS	0	699	36	105	579	59	938	2,416
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC	38	**OPERATING REVENUES**								
RBC										
RBC	39	**SALES REVENUES**								
RBC	40	Sales of Electricity Revenues - Base	0	251,506	16,062	58,920	163,443	38,421	18,565	546,917
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	0	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	0	0	0	0	0	0	0	0
RBC	43	Purchased Electric Revenues	0	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY	0	251,506	16,062	58,920	163,443	38,421	18,565	546,917
RBC										
RBC	45	**OTHER OPERATING REVENUES**								
RBC	46	Unbilled and Cost Adjustment Revenue	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	0	2,979	190	698	1,936	455	220	6,478
RBC	48	454-Rent from Electric Property	0	3,677	593	599	90	4	43	5,005
RBC	49	456-Other Electric Revenues								
RBC	50	Connection Charges/Returned Check Fees/Solar Application Fees/Revenue Protectio	0	0	0	0	0	0	3,998	3,998
RBC	51	All Other	0	903	147	145	0	0	7	1,202
RBC	52	Total 456-Other Electric Revenues	0	903	147	145	0	0	4,004	5,200
RBC	53	TOTAL OTHER OPERATING REV	0	7,559	931	1,442	2,026	459	4,267	16,683
RBC										
RBC	54	**TOTAL OPERATING REVENUES**	0	259,065	16,993	60,361	165,468	38,880	22,832	563,600
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Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBC	30	Equipment Maintenance	0	2	0	0	0	0	0	2
RBC	31	Business Support System	0	0	0	0	0	0	56	56
RBC	32	VEBA Adjustment	0	29	0	4	52	2	9	97
RBC	33	Facilities Contracts	0	1	0	0	0	0	0	1
RBC	34	IT Service Contracts	0	6	1	1	0	0	0	9
RBC	35	Fleet Activities	0	6	0	1	11	0	2	20
RBC	36	Postage	0	0	0	0	0	0	55	55
RBC	37	TOTAL AVERAGE PREPAYMENTS	0	109	6	17	91	9	146	378
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC	38	**OPERATING REVENUES**								
RBC										
RBC	39	**SALES REVENUES**								
RBC	40	Sales of Electricity Revenues - Base	0	31,483	1,812	9,100	24,943	5,957	2,781	76,077
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	0	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	0	0	0	0	0	0	0	0
RBC	43	Purchased Electric Revenues	0	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY	0	31,483	1,812	9,100	24,943	5,957	2,781	76,077
RBC										
RBC	45	**OTHER OPERATING REVENUES**								
RBC	46	Unbilled and Cost Adjustment Revenue	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	0	428	25	124	339	81	38	1,035
RBC	48	454-Rent from Electric Property	0	573	92	97	14	1	7	784
RBC	49	456-Other Electric Revenues								
RBC	50	Connection Charges/Returned Check Fees/Solar Application Fees/Revenue Protectio	0	0	0	0	0	0	623	623
RBC	51	All Other	0	141	23	24	0	0	1	188
RBC	52	Total 456-Other Electric Revenues	0	141	23	24	0	0	624	812
RBC	53	TOTAL OTHER OPERATING REV	0	1,142	140	244	353	82	669	2,631
RBC										
RBC	54	**TOTAL OPERATING REVENUES**	0	32,626	1,952	9,345	25,297	6,039	3,450	78,708
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Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBC	30	Equipment Maintenance	0	1	1	0	0	0	0	3
RBC	31	Business Support System	0	0	0	0	0	0	42	42
RBC	32	VEBA Adjustment	0	21	2	6	31	1	7	68
RBC	33	Facilities Contracts	0	1	1	0	0	0	0	1
RBC	34	IT Service Contracts	0	5	4	2	0	0	0	11
RBC	35	Fleet Activities	0	4	0	1	6	0	1	14
RBC	36	Postage	0	0	0	0	0	0	40	40
RBC	37	TOTAL AVERAGE PREPAYMENTS	0	81	24	26	54	4	105	294
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC	38	**OPERATING REVENUES**								
RBC										
RBC	39	**SALES REVENUES**								
RBC	40	Sales of Electricity Revenues - Base	0	30,017	11,280	14,954	15,399	2,431	(348)	73,733
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	0	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	0	0	0	0	0	0	0	0
RBC	43	Purchased Electric Revenues	0	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY	0	30,017	11,280	14,954	15,399	2,431	(348)	73,733
RBC										
RBC	45	**OTHER OPERATING REVENUES**								
RBC	46	Unbilled and Cost Adjustment Revenue	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	0	174	65	86	89	14	(2)	426
RBC	48	454-Rent from Electric Property	0	425	397	152	8	0	5	986
RBC	49	456-Other Electric Revenues								
RBC	50	Connection Charges/Returned Check Fees/Solar Application Fees/Revenue Protectio	0	0	0	0	0	0	462	462
RBC	51	All Other	0	104	99	37	0	0	1	240
RBC	52	Total 456-Other Electric Revenues	0	104	99	37	0	0	462	702
RBC	53	TOTAL OTHER OPERATING REV	0	702	560	275	97	14	465	2,114
RBC										
RBC	54	**TOTAL OPERATING REVENUES**	0	30,719	11,840	15,228	15,496	2,446	118	75,847
RBC										
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Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBC	30	Equipment Maintenance	0	0	0	0	0	0	0	0
RBC	31	Business Support System	0	0	0	0	0	0	0	0
RBC	32	VEBA Adjustment	0	0	0	0	2	0	0	2
RBC	33	Facilities Contracts	0	0	0	0	0	0	0	0
RBC	34	IT Service Contracts	0	0	0	0	0	0	0	0
RBC	35	Fleet Activities	0	0	0	0	0	0	0	0
RBC	36	Postage	0	0	0	0	0	0	0	0
RBC	37	TOTAL AVERAGE PREPAYMENTS	0	0	0	1	3	0	0	4
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC	38	**OPERATING REVENUES**								
RBC										
RBC	39	**SALES REVENUES**								
RBC	40	Sales of Electricity Revenues - Base	0	0	28	341	890	16	(15)	1,260
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	0	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	0	0	0	0	0	0	0	0
RBC	43	Purchased Electric Revenues	0	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY	0	0	28	341	890	16	(15)	1,260
RBC										
RBC	45	**OTHER OPERATING REVENUES**								
RBC	46	Unbilled and Cost Adjustment Revenue	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	0	0	0	0	0	0	(0)	0
RBC	48	454-Rent from Electric Property	0	0	1	3	1	0	0	5
RBC	49	456-Other Electric Revenues								
RBC	50	Connection Charges/Returned Check Fees/Solar Application Fees/Revenue Protectio	0	0	0	0	0	0	1	1
RBC	51	All Other	0	0	0	1	0	0	0	1
RBC	52	Total 456-Other Electric Revenues	0	0	0	1	0	0	1	2
RBC	53	TOTAL OTHER OPERATING REV	0	0	1	4	1	0	1	8
RBC										
RBC	54	**TOTAL OPERATING REVENUES**	0	0	29	346	891	16	(14)	1,268
RBC										
RBC										
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RBC									

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBC	30	Equipment Maintenance	0	0	0	0	0	0	0	0
RBC	31	Business Support System	0	0	0	0	0	0	1	1
RBC	32	VEBA Adjustment	0	0	0	2	15	0	0	17
RBC	33	Facilities Contracts	0	0	0	0	0	0	0	0
RBC	34	IT Service Contracts	0	0	0	0	0	0	0	1
RBC	35	Fleet Activities	0	0	0	0	3	0	0	3
RBC	36	Postage	0	0	0	0	0	0	1	1
RBC	37	TOTAL AVERAGE PREPAYMENTS	0	0	0	8	26	1	1	36
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC	38	**OPERATING REVENUES**								
RBC										
RBC	39	**SALES REVENUES**								
RBC	40	Sales of Electricity Revenues - Base	0	0	196	4,218	7,205	534	(466)	11,687
RBC	41	Sales of Electricity Revenues - Nuclear Decommissioning	0	0	0	0	0	0	0	0
RBC	42	Transmission Revenues	0	0	0	0	0	0	0	0
RBC	43	Purchased Electric Revenues	0	0	0	0	0	0	0	0
RBC	44	TOTAL SALES OF ELECTRICITY	0	0	196	4,218	7,205	534	(466)	11,687
RBC										
RBC	45	**OTHER OPERATING REVENUES**								
RBC	46	Unbilled and Cost Adjustment Revenue	0	0	0	0	0	0	0	0
RBC	47	450-Forfeited Discounts	0	0	0	2	3	0	(0)	5
RBC	48	454-Rent from Electric Property	0	0	7	43	4	0	0	55
RBC	49	456-Other Electric Revenues								
RBC	50	Connection Charges/Returned Check Fees/Solar Application Fees/Revenue Protectio	0	0	0	0	0	0	8	8
RBC	51	All Other	0	0	2	10	0	0	0	12
RBC	52	Total 456-Other Electric Revenues	0	0	2	10	0	0	8	21
RBC	53	TOTAL OTHER OPERATING REV	0	0	9	56	7	0	8	80
RBC										
RBC	54	**TOTAL OPERATING REVENUES**	0	0	205	4,274	7,213	534	(458)	11,767
RBC										
RBC										
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RBC										
RBC										
RBC										
RBC									

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC			.	.	.	.	.	.	.	.
E	1	**OPERATION & MAINTENANCE EXPENSE**								
E										
E	2	PRODUCTION EXPENSE								
E	3	Other Power Supply								
E	4	555 - Purchased Power - Capacity	0	0	0	0	0	0	0	0
E	5	Total Other Power Supply	0	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE	0	0	0	0	0	0	0	0
E										
E	7	TRANSMISSION EXPENSES								
E	8	Operation Expense	0	0	0	0	0	0	0	0
E	9	Maintenance Expense	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE	0	0	0	0	0	0	0	0
E										
E	11	DISTRIBUTION EXPENSES								
E	12	Operation								
E	13	Account 577 - Energy Storage Expense - Operation								
E	14	577.1 Operation Supervision and Engineering	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	0	0	0	0	0	0	0	0
E	17	577.4 Rents	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	0	0	0	0	0	0	0	0
E	19	Total Account 577	0	0	0	0	0	0	0	0
E	20	580-Supervision	0	56	4	48	0	0	123	233
E	21	581-Load Dispatch	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	0	0	0	0	0	0	0	0
E	23	583-Overhead Lines	0	3,767	0	0	0	0	0	3,767
E	24	584-Underground Lines	0	2,105	0	0	0	0	0	2,105
E	25	585-Street Lighting	0	0	0	0	0	0	0	0
E	26	586-Metering	0	0	0	4,344	0	0	0	4,344
E	27	587-Customer Installations	0	0	0	0	0	0	10,418	10,418
E	28	588-Miscellaneous	0	11,929	1,948	1,916	0	0	88	15,882
E	29	589-Rents	0	546	89	88	0	0	4	727
E	30	Total Distribution Operation	0	18,404	2,042	6,396	0	0	10,634	37,475
E										
E	31	Maintenance								
E	32	578 - Energy Storage Expense - Maintenance								
E	33	578.1 Maintenance Supervision and Engineering (Major Only)	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structures (Major Only)	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Only)	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Plant (Major Only)	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor Only)	0	0	0	0	0	0	0	0
E	40	Total Account 578	0	0	0	0	0	0	0	0
E	41	590-Supervision	0	0	0	0	0	0	0	0
E	42	591-Structures	0	0	0	0	0	0	0	0
E	43	592-Station Equipment								
E	44	592.1-Structures and Equipment	0	0	0	0	0	0	0	0
E	45	592.2-Computer Hardware	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
E	1	**OPERATION & MAINTENANCE EXPENSE**								
E										
E	2	PRODUCTION EXPENSE								
E	3	Other Power Supply								
E	4	555 - Purchased Power - Capacity	0	0	0	0	0	0	0	0
E	5	Total Other Power Supply	0	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE	0	0	0	0	0	0	0	0
E										
E	7	TRANSMISSION EXPENSES								
E	8	Operation Expense	0	0	0	0	0	0	0	0
E	9	Maintenance Expense	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE	0	0	0	0	0	0	0	0
E										
E	11	DISTRIBUTION EXPENSES								
E	12	Operation								
E	13	Account 577 - Energy Storage Expense - Operation								
E	14	577.1 Operation Supervision and Engineering	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	0	0	0	0	0	0	0	0
E	17	577.4 Rents	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	0	0	0	0	0	0	0	0
E	19	Total Account 577	0	0	0	0	0	0	0	0
E	20	580-Supervision	0	9	1	8	0	0	19	37
E	21	581-Load Dispatch	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	0	0	0	0	0	0	0	0
E	23	583-Overhead Lines	0	587	0	0	0	0	0	587
E	24	584-Underground Lines	0	328	0	0	0	0	0	328
E	25	585-Street Lighting	0	0	0	0	0	0	0	0
E	26	586-Metering	0	0	0	704	0	0	0	704
E	27	587-Customer Installations	0	0	0	0	0	0	1,625	1,625
E	28	588-Miscellaneous	0	1,860	304	311	0	0	14	2,488
E	29	589-Rents	0	85	14	14	0	0	1	114
E	30	Total Distribution Operation	0	2,870	318	1,036	0	0	1,658	5,883
E										
E	31	Maintenance								
E	32	578 - Energy Storage Expense - Maintenance								
E	33	578.1 Maintenance Supervision and Engineering (Major Only)	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structures (Major Only)	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Only)	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Plant (Major Only)	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor Only)	0	0	0	0	0	0	0	0
E	40	Total Account 578	0	0	0	0	0	0	0	0
E	41	590-Supervision	0	0	0	0	0	0	0	0
E	42	591-Structures	0	0	0	0	0	0	0	0
E	43	592-Station Equipment								
E	44	592.1-Structures and Equipment	0	0	0	0	0	0	0	0
E	45	592.2-Computer Hardware	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
E	1	**OPERATION & MAINTENANCE EXPENSE**								
E										
E	2	PRODUCTION EXPENSE								
E	3	Other Power Supply								
E	4	555 - Purchased Power - Capacity	0	0	0	0	0	0	0	0
E	5	Total Other Power Supply	0	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE	0	0	0	0	0	0	0	0
E										
E	7	TRANSMISSION EXPENSES								
E	8	Operation Expense	0	0	0	0	0	0	0	0
E	9	Maintenance Expense	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE	0	0	0	0	0	0	0	0
E										
E	11	DISTRIBUTION EXPENSES								
E	12	Operation								
E	13	Account 577 - Energy Storage Expense - Operation								
E	14	577.1 Operation Supervision and Engineering	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	0	0	0	0	0	0	0	0
E	17	577.4 Rents	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	0	0	0	0	0	0	0	0
E	19	Total Account 577	0	0	0	0	0	0	0	0
E	20	580-Supervision	0	7	3	12	0	0	14	36
E	21	581-Load Dispatch	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	0	0	0	0	0	0	0	0
E	23	583-Overhead Lines	0	435	0	0	0	0	0	435
E	24	584-Underground Lines	0	243	0	0	0	0	0	243
E	25	585-Street Lighting	0	0	0	0	0	0	0	0
E	26	586-Metering	0	0	0	1,099	0	0	0	1,099
E	27	587-Customer Installations	0	0	0	0	0	0	1,203	1,203
E	28	588-Miscellaneous	0	1,377	1,303	485	0	0	10	3,175
E	29	589-Rents	0	63	60	22	0	0	0	145
E	30	Total Distribution Operation	0	2,125	1,366	1,619	0	0	1,228	6,337
E										
E	31	Maintenance								
E	32	578 - Energy Storage Expense - Maintenance								
E	33	578.1 Maintenance Supervision and Engineering (Major Only)	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structures (Major Only)	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Only)	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Plant (Major Only)	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor Only)	0	0	0	0	0	0	0	0
E	40	Total Account 578	0	0	0	0	0	0	0	0
E	41	590-Supervision	0	0	0	0	0	0	0	0
E	42	591-Structures	0	0	0	0	0	0	0	0
E	43	592-Station Equipment								
E	44	592.1-Structures and Equipment	0	0	0	0	0	0	0	0
E	45	592.2-Computer Hardware	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
E	1	**OPERATION & MAINTENANCE EXPENSE**								
E										
E	2	PRODUCTION EXPENSE								
E	3	Other Power Supply								
E	4	555 - Purchased Power - Capacity	0	0	0	0	0	0	0	0
E	5	Total Other Power Supply	0	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE	0	0	0	0	0	0	0	0
E										
E	7	TRANSMISSION EXPENSES								
E	8	Operation Expense	0	0	0	0	0	0	0	0
E	9	Maintenance Expense	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE	0	0	0	0	0	0	0	0
E										
E	11	DISTRIBUTION EXPENSES								
E	12	Operation								
E	13	Account 577 - Energy Storage Expense - Operation								
E	14	577.1 Operation Supervision and Engineering	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	0	0	0	0	0	0	0	0
E	17	577.4 Rents	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	0	0	0	0	0	0	0	0
E	19	Total Account 577	0	0	0	0	0	0	0	0
E	20	580-Supervision	0	0	0	0	0	0	0	0
E	21	581-Load Dispatch	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	0	0	0	0	0	0	0	0
E	23	583-Overhead Lines	0	0	0	0	0	0	0	0
E	24	584-Underground Lines	0	0	0	0	0	0	0	0
E	25	585-Street Lighting	0	0	0	0	0	0	0	0
E	26	586-Metering	0	0	0	25	0	0	0	25
E	27	587-Customer Installations	0	0	0	0	0	0	3	3
E	28	588-Miscellaneous	0	0	3	11	0	0	0	14
E	29	589-Rents	0	0	0	1	0	0	0	1
E	30	Total Distribution Operation	0	0	3	37	0	0	3	43
E										
E	31	Maintenance								
E	32	578 - Energy Storage Expense - Maintenance								
E	33	578.1 Maintenance Supervision and Engineering (Major Only)	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structures (Major Only)	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Only)	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Plant (Major Only)	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor Only)	0	0	0	0	0	0	0	0
E	40	Total Account 578	0	0	0	0	0	0	0	0
E	41	590-Supervision	0	0	0	0	0	0	0	0
E	42	591-Structures	0	0	0	0	0	0	0	0
E	43	592-Station Equipment								
E	44	592.1-Structures and Equipment	0	0	0	0	0	0	0	0
E	45	592.2-Computer Hardware	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
RBC										
E	1	**OPERATION & MAINTENANCE EXPENSE**								
E										
E	2	PRODUCTION EXPENSE								
E	3	Other Power Supply								
E	4	555 - Purchased Power - Capacity	0	0	0	0	0	0	0	0
E	5	Total Other Power Supply	0	0	0	0	0	0	0	0
E	6	TOTAL PRODUCTION EXPENSE	0	0	0	0	0	0	0	0
E										
E	7	TRANSMISSION EXPENSES								
E	8	Operation Expense	0	0	0	0	0	0	0	0
E	9	Maintenance Expense	0	0	0	0	0	0	0	0
E	10	TOTAL TRANSMISSION EXPENSE	0	0	0	0	0	0	0	0
E										
E	11	DISTRIBUTION EXPENSES								
E	12	Operation								
E	13	Account 577 - Energy Storage Expense - Operation								
E	14	577.1 Operation Supervision and Engineering	0	0	0	0	0	0	0	0
E	15	577.2 Operation of Energy Storage Equipment (Major Only)	0	0	0	0	0	0	0	0
E	16	577.3 Storage Fuel	0	0	0	0	0	0	0	0
E	17	577.4 Rents	0	0	0	0	0	0	0	0
E	18	577.5 Operation Supplies and Expenses (Nonmajor Only)	0	0	0	0	0	0	0	0
E	19	Total Account 577	0	0	0	0	0	0	0	0
E	20	580-Supervision	0	0	0	3	0	0	0	4
E	21	581-Load Dispatch	0	0	0	0	0	0	0	0
E	22	582-Station Equipment	0	0	0	0	0	0	0	0
E	23	583-Overhead Lines	0	0	0	0	0	0	0	0
E	24	584-Underground Lines	0	0	0	0	0	0	0	0
E	25	585-Street Lighting	0	0	0	0	0	0	0	0
E	26	586-Metering	0	0	0	314	0	0	0	314
E	27	587-Customer Installations	0	0	0	0	0	0	22	22
E	28	588-Miscellaneous	0	0	23	139	0	0	0	162
E	29	589-Rents	0	0	1	6	0	0	0	7
E	30	Total Distribution Operation	0	0	24	463	0	0	22	509
E										
E	31	Maintenance								
E	32	578 - Energy Storage Expense - Maintenance								
E	33	578.1 Maintenance Supervision and Engineering (Major Only)	0	0	0	0	0	0	0	0
E	34	578.2 Maintenance of Energy Storage Equipment and Structures (Major Only)	0	0	0	0	0	0	0	0
E	35	578.3 Maintenance of Computer Hardware (Major Only)	0	0	0	0	0	0	0	0
E	36	578.4 Maintenance of Computer Software (Major Only)	0	0	0	0	0	0	0	0
E	37	578.5 Maintenance of Communication Equipment (Major Only)	0	0	0	0	0	0	0	0
E	38	578.6 Maintenance of Miscellaneous Other Energy Storage Plant (Major Only)	0	0	0	0	0	0	0	0
E	39	578.7 Maintenance of Other Energy Storage Plant (Nonmajor Only)	0	0	0	0	0	0	0	0
E	40	Total Account 578	0	0	0	0	0	0	0	0
E	41	590-Supervision	0	0	0	0	0	0	0	0
E	42	591-Structures	0	0	0	0	0	0	0	0
E	43	592-Station Equipment								
E	44	592.1-Structures and Equipment	0	0	0	0	0	0	0	0
E	45	592.2-Computer Hardware	0	0	0	0	0	0	0	0
E	46	592.3-Computer Software	0	0	0	0	0	0	0	0
E	47	592.4-Communication Equipment	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
E	48	Total Account 592	0	0	0	0	0	0	0	0
E	49	593-Overhead Lines	0	42,699	0	0	0	0	0	42,699
E	50	594-Underground Lines	0	6,701	0	0	0	0	0	6,701
E	51	595-Transformers	0	0	0	0	0	0	0	0
E	52	596-Street Lighting	0	0	0	0	0	0	0	0
E	53	597-Metering	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	0	2,347	383	377	0	0	17	3,125
E	55	Total Distribution Maintenance	0	51,747	383	377	0	0	17	52,525
E										
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES	0	70,151	2,425	6,773	0	0	10,651	90,000
E	57	TOTAL PURCHASED POWER O&M EXPENSES	0	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES	0	0	0	0	0	0	0	0
E										
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)	0	70,151	2,425	6,773	0	0	10,651	90,000
E										
E										
E										
E										
E										
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
E										
E	61	CUSTOMER ACCOUNTS EXPENSES								
E	62	901-Supervision	0	0	0	0	0	0	0	0
E	63	902-Meter Reading	0	0	0	167	0	0	0	167
E	64	903-Customer Records and Collection Expense	0	0	0	0	78,676	0	0	78,676
E	65	904-Uncollectible Accounts	0	9,443	603	2,212	6,137	1,443	697	20,535
E	66	905-Miscellaneous CA	0	0	0	0	5,346	0	0	5,346
E	67	TOTAL CUSTOMER ACCTS EXPENSE	0	9,443	603	2,379	90,158	1,443	697	104,724
E										
E										
E	68	CUSTOMER SERVICE EXPENSES								
E	69	907-Supervision	0	0	0	0	0	0	0	0
E	70	908-Customer Assistance	0	0	0	0	0	29,258	0	29,258
E	71	909-Informational Advertisement	0	0	0	0	0	1,900	0	1,900
E	72	910-Miscellaneous CS	0	0	0	0	0	729	0	729
E	73	TOTAL CUSTOMER SERVICE EXPENSE	0	0	0	0	0	31,887	0	31,887
E										
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	0	0	0	0	0	0	0	0
E										
E	75	TOTAL OPER & MAINT EXCL A&G	0	79,594	3,028	9,152	90,158	33,330	11,348	226,611
E										
E	76	ADMINISTRATIVE & GENERAL EXPENSE								
E	77	920-Administrative Salaries	0	4,428	72	576	7,895	360	1,419	14,750
E	78	921-Office Supplies & Expense	0	482	8	63	859	39	154	1,605
E	79	923-Outside Service Employed	0	11,423	186	1,487	20,367	930	3,660	38,052
E	80	924-Property Insurance	0	129	21	21	3	0	2	175
E	81	925-Injuries and Damages	0	2,099	34	273	3,743	171	673	6,994
E	82	926-Employee Pensions & Benefits	0	3,697	60	481	6,591	301	1,184	12,315
E	83	928-Regulatory Commission	0	714	49	144	393	90	44	1,434
E	84	929-Duplicate Charges-Credit	(0)	(150)	(10)	(30)	(83)	(19)	(9)	(302)
E	85	930.2-Miscellaneous General								
E	86	R/RH	0	0	0	0	0	0	0	0
E	87	GS	0	0	0	0	0	0	0	0
E	88	GS/PD/HT	0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	0	0	0	0	0	0	0	0
E	91	All Other	0	108	7	22	59	14	7	216

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
E	48	Total Account 592	0	0	0	0	0	0	0	0
E	49	593-Overhead Lines	0	6,659	0	0	0	0	0	6,659
E	50	594-Underground Lines	0	1,045	0	0	0	0	0	1,045
E	51	595-Transformers	0	0	0	0	0	0	0	0
E	52	596-Street Lighting	0	0	0	0	0	0	0	0
E	53	597-Metering	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	0	366	60	61	0	0	3	490
E	55	Total Distribution Maintenance	0	8,070	60	61	0	0	3	8,193
E										
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES	0	10,940	378	1,098	0	0	1,661	14,076
E	57	TOTAL PURCHASED POWER O&M EXPENSES	0	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES	0	0	0	0	0	0	0	0
E										
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)	0	10,940	378	1,098	0	0	1,661	14,076
E										
E										
E										
E										
E										
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
E										
E	61	CUSTOMER ACCOUNTS EXPENSES								
E	62	901-Supervision	0	0	0	0	0	0	0	0
E	63	902-Meter Reading	0	0	0	27	0	0	0	27
E	64	903-Customer Records and Collection Expense	0	0	0	0	12,399	0	0	12,399
E	65	904-Uncollectible Accounts	0	1,358	78	392	1,076	257	120	3,280
E	66	905-Miscellaneous CA	0	0	0	0	834	0	0	834
E	67	TOTAL CUSTOMER ACCTS EXPENSE	0	1,358	78	419	14,309	257	120	16,540
E										
E										
E	68	CUSTOMER SERVICE EXPENSES								
E	69	907-Supervision	0	0	0	0	0	0	0	0
E	70	908-Customer Assistance	0	0	0	0	0	4,563	0	4,563
E	71	909-Informational Advertisement	0	0	0	0	0	296	0	296
E	72	910-Miscellaneous CS	0	0	0	0	0	114	0	114
E	73	TOTAL CUSTOMER SERVICE EXPENSE	0	0	0	0	0	4,973	0	4,973
E										
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	0	0	0	0	0	0	0	0
E										
E	75	TOTAL OPER & MAINT EXCL A&G	0	12,297	456	1,517	14,309	5,229	1,781	35,589
E										
E	76	ADMINISTRATIVE & GENERAL EXPENSE								
E	77	920-Administrative Salaries	0	691	11	93	1,244	56	221	2,316
E	78	921-Office Supplies & Expense	0	75	1	10	135	6	24	252
E	79	923-Outside Service Employed	0	1,781	29	241	3,209	145	571	5,976
E	80	924-Property Insurance	0	20	3	3	0	0	0	27
E	81	925-Injuries and Damages	0	327	5	44	590	27	105	1,098
E	82	926-Employee Pensions & Benefits	0	577	9	78	1,039	47	185	1,934
E	83	928-Regulatory Commission	0	111	8	23	62	14	7	225
E	84	929-Duplicate Charges-Credit	(0)	(23)	(2)	(5)	(13)	(3)	(1)	(47)
E	85	930.2-Miscellaneous General								
E	86	R/RH	0	0	0	0	0	0	0	0
E	87	GS	0	0	0	0	0	0	0	0
E	88	GS/PD/HT	0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	0	0	0	0	0	0	0	0
E	91	All Other	0	17	1	4	9	2	1	34

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
E	48	Total Account 592	0	0	0	0	0	0	0	0
E	49	593-Overhead Lines	0	4,930	0	0	0	0	0	4,930
E	50	594-Underground Lines	0	774	0	0	0	0	0	774
E	51	595-Transformers	0	0	0	0	0	0	0	0
E	52	596-Street Lighting	0	0	0	0	0	0	0	0
E	53	597-Metering	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	0	271	256	95	0	0	2	625
E	55	Total Distribution Maintenance	0	5,975	256	95	0	0	2	6,329
E										
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES	0	8,100	1,622	1,714	0	0	1,230	12,666
E	57	TOTAL PURCHASED POWER O&M EXPENSES	0	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES	0	0	0	0	0	0	0	0
E										
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)	0	8,100	1,622	1,714	0	0	1,230	12,666
E										
E										
E										
E										
E										
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
E										
E	61	CUSTOMER ACCOUNTS EXPENSES								
E	62	901-Supervision	0	0	0	0	0	0	0	0
E	63	902-Meter Reading	0	0	0	42	0	0	0	42
E	64	903-Customer Records and Collection Expense	0	0	0	0	7,331	0	0	7,331
E	65	904-Uncollectible Accounts	0	550	207	274	282	45	(6)	1,351
E	66	905-Miscellaneous CA	0	0	0	0	617	0	0	617
E	67	TOTAL CUSTOMER ACCTS EXPENSE	0	550	207	316	8,231	45	(6)	9,342
E										
E										
E	68	CUSTOMER SERVICE EXPENSES								
E	69	907-Supervision	0	0	0	0	0	0	0	0
E	70	908-Customer Assistance	0	0	0	0	0	1,495	0	1,495
E	71	909-Informational Advertisement	0	0	0	0	0	219	0	219
E	72	910-Miscellaneous CS	0	0	0	0	0	84	0	84
E	73	TOTAL CUSTOMER SERVICE EXPENSE	0	0	0	0	0	1,798	0	1,798
E										
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	0	0	0	0	0	266	0	266
E										
E	75	TOTAL OPER & MAINT EXCL A&G	0	8,650	1,829	2,030	8,231	2,108	1,223	24,072
E										
E	76	ADMINISTRATIVE & GENERAL EXPENSE								
E	77	920-Administrative Salaries	0	511	48	146	740	19	164	1,629
E	78	921-Office Supplies & Expense	0	56	5	16	81	2	18	177
E	79	923-Outside Service Employed	0	1,319	124	376	1,910	49	423	4,201
E	80	924-Property Insurance	0	15	14	5	0	0	0	34
E	81	925-Injuries and Damages	0	242	23	69	351	9	78	772
E	82	926-Employee Pensions & Benefits	0	427	40	122	618	16	137	1,360
E	83	928-Regulatory Commission	0	82	33	36	37	6	(3)	191
E	84	929-Duplicate Charges-Credit	(0)	(17)	(7)	(8)	(8)	(1)	1	(40)
E	85	930.2-Miscellaneous General								
E	86	R/RH	0	0	0	0	0	0	0	0
E	87	GS	0	0	0	0	0	0	0	0
E	88	GS/PD/HT	0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	0	0	0	0	0	0	0	0
E	91	All Other	0	12	5	5	6	1	(0)	29

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
E	48	Total Account 592	0	0	0	0	0	0	0	0
E	49	593-Overhead Lines	0	0	0	0	0	0	0	0
E	50	594-Underground Lines	0	0	0	0	0	0	0	0
E	51	595-Transformers	0	0	0	0	0	0	0	0
E	52	596-Street Lighting	0	0	0	0	0	0	0	0
E	53	597-Metering	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	0	0	1	2	0	0	0	3
E	55	Total Distribution Maintenance	0	0	1	2	0	0	0	3
E										
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES	0	0	4	39	0	0	3	46
E	57	TOTAL PURCHASED POWER O&M EXPENSES	0	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES	0	0	0	0	0	0	0	0
E										
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)	0	0	4	39	0	0	3	46
E										
E										
E										
E										
E										
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
E										
E	61	CUSTOMER ACCOUNTS EXPENSES								
E	62	901-Supervision	0	0	0	0	0	0	0	0
E	63	902-Meter Reading	0	0	0	1	0	0	0	1
E	64	903-Customer Records and Collection Expense	0	0	0	0	452	0	0	452
E	65	904-Uncollectible Accounts	0	0	0	0	1	0	(0)	2
E	66	905-Miscellaneous CA	0	0	0	0	1	0	0	1
E	67	TOTAL CUSTOMER ACCTS EXPENSE	0	0	0	1	454	0	(0)	456
E										
E										
E	68	CUSTOMER SERVICE EXPENSES								
E	69	907-Supervision	0	0	0	0	0	0	0	0
E	70	908-Customer Assistance	0	0	0	0	0	4	0	4
E	71	909-Informational Advertisement	0	0	0	0	0	1	0	1
E	72	910-Miscellaneous CS	0	0	0	0	0	0	0	0
E	73	TOTAL CUSTOMER SERVICE EXPENSE	0	0	0	0	0	4	0	4
E										
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	0	0	0	0	0	10	0	10
E										
E	75	TOTAL OPER & MAINT EXCL A&G	0	0	4	41	454	14	3	516
E										
E	76	ADMINISTRATIVE & GENERAL EXPENSE								
E	77	920-Administrative Salaries	0	0	0	3	44	0	0	48
E	78	921-Office Supplies & Expense	0	0	0	0	5	0	0	5
E	79	923-Outside Service Employed	0	0	0	9	114	0	1	124
E	80	924-Property Insurance	0	0	0	0	0	0	0	0
E	81	925-Injuries and Damages	0	0	0	2	21	0	0	23
E	82	926-Employee Pensions & Benefits	0	0	0	3	37	0	0	40
E	83	928-Regulatory Commission	0	0	0	1	2	0	(0)	3
E	84	929-Duplicate Charges-Credit	(0)	(0)	(0)	(0)	(0)	(0)	0	(1)
E	85	930.2-Miscellaneous General								
E	86	R/RH	0	0	0	0	0	0	0	0
E	87	GS	0	0	0	0	0	0	0	0
E	88	GS/PD/HT	0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	0	0	0	0	0	0	0	0
E	91	All Other	0	0	0	0	0	0	(0)	0

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
E	48	Total Account 592	0	0	0	0	0	0	0	0
E	49	593-Overhead Lines	0	0	0	0	0	0	0	0
E	50	594-Underground Lines	0	0	0	0	0	0	0	0
E	51	595-Transformers	0	0	0	0	0	0	0	0
E	52	596-Street Lighting	0	0	0	0	0	0	0	0
E	53	597-Metering	0	0	0	0	0	0	0	0
E	54	598-Miscellaneous	0	0	5	27	0	0	0	32
E	55	Total Distribution Maintenance	0	0	5	27	0	0	0	32
E										
E	56	TOTAL DISTRIBUTION PLANT O&M EXPENSES	0	0	29	490	0	0	22	541
E	57	TOTAL PURCHASED POWER O&M EXPENSES	0	0	0	0	0	0	0	0
E	58	TOTAL TRANSMISSION O&M EXPENSES	0	0	0	0	0	0	0	0
E										
E	59	TOTAL OPER. & MAINT. EXP. (PROD,TRAN,& DIST)	0	0	29	490	0	0	22	541
E										
E										
E										
E										
E										
E	60	**OPERATION & MAINTENANCE EXPENSE CONTINUED**								
E										
E	61	CUSTOMER ACCOUNTS EXPENSES								
E	62	901-Supervision	0	0	0	0	0	0	0	0
E	63	902-Meter Reading	0	0	0	12	0	0	0	12
E	64	903-Customer Records and Collection Expense	0	0	0	0	3,680	0	0	3,680
E	65	904-Uncollectible Accounts	0	0	0	6	11	1	(1)	17
E	66	905-Miscellaneous CA	0	0	0	0	11	0	0	11
E	67	TOTAL CUSTOMER ACCTS EXPENSE	0	0	0	18	3,701	1	(1)	3,720
E										
E										
E	68	CUSTOMER SERVICE EXPENSES								
E	69	907-Supervision	0	0	0	0	0	0	0	0
E	70	908-Customer Assistance	0	0	0	0	0	27	0	27
E	71	909-Informational Advertisement	0	0	0	0	0	4	0	4
E	72	910-Miscellaneous CS	0	0	0	0	0	2	0	2
E	73	TOTAL CUSTOMER SERVICE EXPENSE	0	0	0	0	0	32	0	32
E										
E	74	SALES EXPENSES TOTAL (ACCT 912 & 916)	0	0	0	0	0	458	0	458
E										
E	75	TOTAL OPER & MAINT EXCL A&G	0	0	29	508	3,701	491	21	4,751
E										
E	76	ADMINISTRATIVE & GENERAL EXPENSE								
E	77	920-Administrative Salaries	0	0	1	42	360	0	3	405
E	78	921-Office Supplies & Expense	0	0	0	5	39	0	0	44
E	79	923-Outside Service Employed	0	0	2	108	928	1	8	1,046
E	80	924-Property Insurance	0	0	0	1	0	0	0	2
E	81	925-Injuries and Damages	0	0	0	20	170	0	1	192
E	82	926-Employee Pensions & Benefits	0	0	1	35	300	0	2	338
E	83	928-Regulatory Commission	0	0	1	10	17	1	(2)	28
E	84	929-Duplicate Charges-Credit	(0)	(0)	(0)	(2)	(4)	(0)	0	(6)
E	85	930.2-Miscellaneous General								
E	86	R/RH	0	0	0	0	0	0	0	0
E	87	GS	0	0	0	0	0	0	0	0
E	88	GS/PD/HT	0	0	0	0	0	0	0	0
E	89	Transit Charging - GS	0	0	0	0	0	0	0	0
E	90	Transit Charging - PD/HT	0	0	0	0	0	0	0	0
E	91	All Other	0	0	0	2	3	0	(0)	4

Sch.	LineNo.	Description	Residential							
			CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
E	92	Total 930.2-Miscellaneous General	0	108	7	22	59	14	7	216
E	93	935-Maintenance of General Plant								
E	94	935-Maintenance of General Plant	0	1,127	18	147	2,010	92	361	3,755
E	95	935.1-Maintenance of Computer Hardware	0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	0	0	0	0	0	0	0	0
E	98	Total Account 935	0	1,127	18	147	2,010	92	361	3,755
E	99	TOTAL A&G EXPENSE	0	24,057	446	3,183	41,837	1,977	7,494	78,994
E										
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**	0	103,651	3,474	12,336	131,996	35,307	18,842	305,605
E										
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**	0	103,651	3,474	12,336	131,996	35,307	18,842	305,605
E										
E										
E										
E										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**								
D										
D	2	INTANGIBLE PLANT EXPENSE	0	104	17	25,434	0	0	1	25,556
D										
D	3	TRANSMISSION PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	4	DISTRIBUTION PLANT EXPENSE								
D	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
D	7	362-Station Equipment	0	0	0	0	0	0	0	0
D	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
D	9	364-Poles,Towers & Fixtures	0	10,037	0	0	0	0	0	10,037
D	10	365-Overhead Conductors & Devices	0	13,253	0	0	0	0	0	13,253
D	11	366-Underground Conduit	0	4,259	0	0	0	0	0	4,259
D	12	367-Underground Conductors & Devices	0	11,048	0	0	0	0	0	11,048
D	13	368-Line Transformers	0	0	0	0	0	0	0	0
D	14	369-Services	0	0	4,801	0	0	0	0	4,801
D	15	370-Meters	0	0	0	13,798	0	0	0	13,798
D	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
D	18	374-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE	0	38,597	4,801	13,798	0	0	0	57,196
D										
D	20	ENERGY STORAGE PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	21	GENERAL PLANT EXPENSE	0	5,105	83	665	9,103	415	1,636	17,007
D										
D	22	BESS DEPRECIATION	0	59	0	0	0	0	0	59
D										
D	23	REG ASSET AMORTIZATION	0	2,199	355	358	54	2	26	2,994
D										
D										
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**	0	46,065	5,256	40,255	9,156	418	1,662	102,812
D										
D										
D										
D										
D										
D										
D										
D										

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
E	92	Total 930.2-Miscellaneous General	0	17	1	4	9	2	1	34
E	93	935-Maintenance of General Plant								
E	94	935-Maintenance of General Plant	0	176	3	24	317	14	56	590
E	95	935.1-Maintenance of Computer Hardware	0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	0	0	0	0	0	0	0	0
E	98	Total Account 935	0	176	3	24	317	14	56	590
E	99	TOTAL A&G EXPENSE	0	3,751	69	516	6,592	308	1,168	12,405
E										
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**	0	16,048	526	2,033	20,900	5,538	2,949	47,995
E										
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**	0	16,048	526	2,033	20,900	5,538	2,949	47,995
E										
E										
E										
E										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**								
D										
D	2	INTANGIBLE PLANT EXPENSE	0	16	3	4,122	0	0	0	4,141
D										
D	3	TRANSMISSION PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	4	DISTRIBUTION PLANT EXPENSE								
D	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
D	7	362-Station Equipment	0	0	0	0	0	0	0	0
D	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
D	9	364-Poles,Towers & Fixtures	0	1,565	0	0	0	0	0	1,565
D	10	365-Overhead Conductors & Devices	0	2,067	0	0	0	0	0	2,067
D	11	366-Underground Conduit	0	664	0	0	0	0	0	664
D	12	367-Underground Conductors & Devices	0	1,723	0	0	0	0	0	1,723
D	13	368-Line Transformers	0	0	0	0	0	0	0	0
D	14	369-Services	0	0	749	0	0	0	0	749
D	15	370-Meters	0	0	0	2,236	0	0	0	2,236
D	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
D	18	374-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE	0	6,019	749	2,236	0	0	0	9,004
D										
D	20	ENERGY STORAGE PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	21	GENERAL PLANT EXPENSE	0	796	13	108	1,434	65	255	2,671
D										
D	22	BESS DEPRECIATION	0	9	0	0	0	0	0	9
D										
D	23	REG ASSET AMORTIZATION	0	343	55	58	8	0	4	469
D										
D										
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**	0	7,183	820	6,523	1,443	65	259	16,294
D										
D										
D										
D										
D										
D										
D										

Sch.	LineNo.	Description	General Service							
			CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
E	92	Total 930.2-Miscellaneous General	0	12	5	5	6	1	(0)	29
E	93	935-Maintenance of General Plant								
E	94	935-Maintenance of General Plant	0	130	12	37	188	5	42	415
E	95	935.1-Maintenance of Computer Hardware	0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	0	0	0	0	0	0	0	0
E	98	Total Account 935	0	130	12	37	188	5	42	415
E	99	TOTAL A&G EXPENSE	0	2,777	298	805	3,924	104	858	8,767
E										
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**	0	11,427	2,127	2,836	12,155	2,213	2,081	32,838
E										
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**	0	11,427	2,127	2,836	12,155	2,213	2,081	32,838
E										
E										
E										
E										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**								
D										
D	2	INTANGIBLE PLANT EXPENSE	0	12	11	6,437	0	0	0	6,460
D										
D	3	TRANSMISSION PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	4	DISTRIBUTION PLANT EXPENSE								
D	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
D	7	362-Station Equipment	0	0	0	0	0	0	0	0
D	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
D	9	364-Poles,Towers & Fixtures	0	1,159	0	0	0	0	0	1,159
D	10	365-Overhead Conductors & Devices	0	1,530	0	0	0	0	0	1,530
D	11	366-Underground Conduit	0	492	0	0	0	0	0	492
D	12	367-Underground Conductors & Devices	0	1,276	0	0	0	0	0	1,276
D	13	368-Line Transformers	0	0	0	0	0	0	0	0
D	14	369-Services	0	0	3,211	0	0	0	0	3,211
D	15	370-Meters	0	0	0	3,492	0	0	0	3,492
D	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
D	18	374-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE	0	4,457	3,211	3,492	0	0	0	11,159
D										
D	20	ENERGY STORAGE PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	21	GENERAL PLANT EXPENSE	0	589	56	168	854	22	189	1,878
D										
D	22	BESS DEPRECIATION	0	0	0	0	0	0	0	0
D										
D	23	REG ASSET AMORTIZATION	0	254	237	91	5	0	3	590
D										
D										
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**	0	5,312	3,515	10,187	859	22	192	20,087
D										
D										
D										
D										
D										
D										
D										

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
E	92	Total 930.2-Miscellaneous General	0	0	0	0	0	0	(0)	0
E	93	935-Maintenance of General Plant								
E	94	935-Maintenance of General Plant	0	0	0	1	11	0	0	12
E	95	935.1-Maintenance of Computer Hardware	0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	0	0	0	0	0	0	0	0
E	98	Total Account 935	0	0	0	1	11	0	0	12
E	99	TOTAL A&G EXPENSE	0	0	1	18	234	0	2	255
E										
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**	0	0	5	59	688	15	5	771
E										
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**	0	0	5	59	688	15	5	771
E										
E										
E										
E										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**								
D										
D	2	INTANGIBLE PLANT EXPENSE	0	0	0	147	0	0	0	147
D										
D	3	TRANSMISSION PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	4	DISTRIBUTION PLANT EXPENSE								
D	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
D	7	362-Station Equipment	0	0	0	0	0	0	0	0
D	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
D	9	364-Poles,Towers & Fixtures	0	0	0	0	0	0	0	0
D	10	365-Overhead Conductors & Devices	0	0	0	0	0	0	0	0
D	11	366-Underground Conduit	0	0	0	0	0	0	0	0
D	12	367-Underground Conductors & Devices	0	0	0	0	0	0	0	0
D	13	368-Line Transformers	0	0	0	0	0	0	0	0
D	14	369-Services	0	0	8	0	0	0	0	8
D	15	370-Meters	0	0	0	80	0	0	0	80
D	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
D	18	374-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE	0	0	8	80	0	0	0	88
D										
D	20	ENERGY STORAGE PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	21	GENERAL PLANT EXPENSE	0	0	0	4	51	0	0	55
D										
D	22	BESS DEPRECIATION	0	0	0	0	0	0	0	0
D										
D	23	REG ASSET AMORTIZATION	0	0	1	2	0	0	0	3
D										
D										
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**	0	0	8	233	51	0	0	293
D										
D										
D										
D										
D										
D										
D										
D										

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
E	92	Total 930.2-Miscellaneous General	0	0	0	2	3	0	(0)	4
E	93	935-Maintenance of General Plant								
E	94	935-Maintenance of General Plant	0	0	0	11	92	0	1	103
E	95	935.1-Maintenance of Computer Hardware	0	0	0	0	0	0	0	0
E	96	935.2-Maintenance of Computer Software	0	0	0	0	0	0	0	0
E	97	935.3-Maintenance of Communication Equipment	0	0	0	0	0	0	0	0
E	98	Total Account 935	0	0	0	11	92	0	1	103
E	99	TOTAL A&G EXPENSE	0	0	5	230	1,905	3	14	2,157
E										
E	100	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**	0	0	35	738	5,606	494	35	6,908
E										
E	101	**TOTAL OPERATION & MAINTENANCE EXPENSES**	0	0	35	738	5,606	494	35	6,908
E										
E										
E										
E										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**								
D										
D	2	INTANGIBLE PLANT EXPENSE	0	0	0	1,839	0	0	0	1,840
D										
D	3	TRANSMISSION PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	4	DISTRIBUTION PLANT EXPENSE								
D	5	360-Land & Land Rights	0	0	0	0	0	0	0	0
D	6	361-Structures & Improvements	0	0	0	0	0	0	0	0
D	7	362-Station Equipment	0	0	0	0	0	0	0	0
D	8	363-Computer HW SW and Equipment	0	0	0	0	0	0	0	0
D	9	364-Poles,Towers & Fixtures	0	0	0	0	0	0	0	0
D	10	365-Overhead Conductors & Devices	0	0	0	0	0	0	0	0
D	11	366-Underground Conduit	0	0	0	0	0	0	0	0
D	12	367-Underground Conductors & Devices	0	0	0	0	0	0	0	0
D	13	368-Line Transformers	0	0	0	0	0	0	0	0
D	14	369-Services	0	0	57	0	0	0	0	57
D	15	370-Meters	0	0	0	998	0	0	0	998
D	16	371-Installation on Customer Premises	0	0	0	0	0	0	0	0
D	17	373-Street Lighting & Signal Systems	0	0	0	0	0	0	0	0
D	18	374-Asset Retirement Costs for Distribution Plant	0	0	0	0	0	0	0	0
D	19	TOTAL DISTRIBUTION PLANT EXPENSE	0	0	57	998	0	0	0	1,055
D										
D	20	ENERGY STORAGE PLANT EXPENSE	0	0	0	0	0	0	0	0
D										
D	21	GENERAL PLANT EXPENSE	0	0	1	48	415	0	3	467
D										
D	22	BESS DEPRECIATION	0	0	0	0	0	0	0	0
D										
D	23	REG ASSET AMORTIZATION	0	0	4	26	2	0	0	33
D										
D										
D	24	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**	0	0	63	2,911	417	0	3	3,395
D										
D										
D										
D										
D										
D										
D										

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
D										
D										
D										
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D										
D										
TO	1	**OTHER OPERATING EXPENSES**								
TO										
TO	2	**TAXES OTHER THAN INCOME TAXES**								
TO	3	**GENERAL TAXES**								
TO	4	PURTA Taxes	0	0	0	0	0	0	0	0
TO	5	Capital Stock	0	0	0	0	0	0	0	0
TO	6	Payroll Related	0	1,693	28	220	3,018	138	542	5,639
TO	7	Other Property Basis Adjustment (CIAC/ICM) - Federal	0	0	0	0	0	0	0	0
TO	8	Other Property Basis Adjustment (CIAC/ICM) - State	0	0	0	0	0	0	0	0
TO	9	PA & Local Use Tax	0	171	12	34	94	21	11	343
TO	10	PA Property Tax	0	834	135	136	20	1	10	1,135
TO	11	PA Corporate LoanTax	0	0	0	0	0	0	0	0
TO	12	Total General Taxes	0	2,697	174	391	3,132	160	563	7,117
TO										
TO										
TO	13	**GROSS RECEIPTS TAX**								
TO										
TO	14	**PURCHASED POWER**								
TO	15	Retail Revenue	0	0	0	0	0	0	0	0
TO	16	Forfeited Discounts								
TO	17	Less: Bad Debt								
TO	18	Total Purchased Power Revenue	0	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	20	**TRANSMISSION**								
TO	21	Retail Revenue	0	0	0	0	0	0	0	0
TO	22	Forfeited Discounts								
TO	23	Less: Bad Debt								
TO	24	Total Transmission Revenue	0	0	0	0	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	26	**DISTRIBUTION**								
TO	27	Retail Revenue	0	251,506	16,062	58,920	163,443	38,421	18,565	546,917
TO	28	Forfeited Discounts	0	2,979	190	698	1,936	455	220	6,478
TO	29	Less: Bad Debt	0	9,443	603	2,212	6,137	1,443	697	20,535
TO	30	Total Distribution Revenue	0	245,042	15,650	57,405	159,242	37,434	18,088	532,861
TO	31	Total Distribution at 5.90% GRT Rate	0	14,457	923	3,387	9,395	2,209	1,067	31,439
TO										
TO	32	TOTAL GROSS RECEIPTS TAX	0	14,457	923	3,387	9,395	2,209	1,067	31,439
TO										
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES	0	17,155	1,097	3,777	12,528	2,369	1,630	38,556
TO										
TO	36	**TOTAL TAXES OTHER THAN INCOME**	0	17,155	1,097	3,777	12,528	2,369	1,630	38,556
TO										

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
D										
D										
D										
D										
D										
D										
D										
D										
D										
D										
D										
D										
TO	1	**OTHER OPERATING EXPENSES**								
TO										
TO	2	**TAXES OTHER THAN INCOME TAXES**								
TO	3	**GENERAL TAXES**								
TO	4	PURTA Taxes	0	0	0	0	0	0	0	0
TO	5	Capital Stock	0	0	0	0	0	0	0	0
TO	6	Payroll Related	0	264	4	36	476	21	85	886
TO	7	Other Property Basis Adjustment (CIAC/ICM) - Federal	0	0	0	0	0	0	0	0
TO	8	Other Property Basis Adjustment (CIAC/ICM) - State	0	0	0	0	0	0	0	0
TO	9	PA & Local Use Tax	0	27	2	6	15	3	2	54
TO	10	PA Property Tax	0	130	21	22	3	0	2	178
TO	11	PA Corporate LoanTax	0	0	0	0	0	0	0	0
TO	12	Total General Taxes	0	421	27	63	494	25	88	1,117
TO										
TO										
TO	13	**GROSS RECEIPTS TAX**								
TO										
TO	14	**PURCHASED POWER**								
TO	15	Retail Revenue	0	0	0	0	0	0	0	0
TO	16	Forfeited Discounts								
TO	17	Less: Bad Debt								
TO	18	Total Purchased Power Revenue	0	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	20	**TRANSMISSION**								
TO	21	Retail Revenue	0	0	0	0	0	0	0	0
TO	22	Forfeited Discounts								
TO	23	Less: Bad Debt								
TO	24	Total Transmission Revenue	0	0	0	0	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	26	**DISTRIBUTION**								
TO	27	Retail Revenue	0	31,483	1,812	9,100	24,943	5,957	2,781	76,077
TO	28	Forfeited Discounts	0	428	25	124	339	81	38	1,035
TO	29	Less: Bad Debt	0	1,358	78	392	1,076	257	120	3,280
TO	30	Total Distribution Revenue	0	30,554	1,759	8,832	24,207	5,781	2,699	73,832
TO	31	Total Distribution at 5.90% GRT Rate	0	1,803	104	521	1,428	341	159	4,356
TO										
TO	32	TOTAL GROSS RECEIPTS TAX	0	1,803	104	521	1,428	341	159	4,356
TO										
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES	0	2,223	131	584	1,922	366	247	5,473
TO										
TO	36	**TOTAL TAXES OTHER THAN INCOME**	0	2,223	131	584	1,922	366	247	5,473
TO										

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
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TO	1	**OTHER OPERATING EXPENSES**								
TO										
TO	2	**TAXES OTHER THAN INCOME TAXES**								
TO	3	**GENERAL TAXES**								
TO	4	PURTA Taxes	0	0	0	0	0	0	0	0
TO	5	Capital Stock	0	0	0	0	0	0	0	0
TO	6	Payroll Related	0	195	18	56	283	7	63	623
TO	7	Other Property Basis Adjustment (CIAC/ICM) - Federal	0	0	0	0	0	0	0	0
TO	8	Other Property Basis Adjustment (CIAC/ICM) - State	0	0	0	0	0	0	0	0
TO	9	PA & Local Use Tax	0	20	8	9	9	1	(1)	46
TO	10	PA Property Tax	0	96	90	34	2	0	1	224
TO	11	PA Corporate LoanTax	0	0	0	0	0	0	0	0
TO	12	Total General Taxes	0	311	116	99	294	9	63	892
TO										
TO										
TO	13	**GROSS RECEIPTS TAX**								
TO										
TO	14	**PURCHASED POWER**								
TO	15	Retail Revenue	0	0	0	0	0	0	0	0
TO	16	Forfeited Discounts								
TO	17	Less: Bad Debt								
TO	18	Total Purchased Power Revenue	0	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	20	**TRANSMISSION**								
TO	21	Retail Revenue	0	0	0	0	0	0	0	0
TO	22	Forfeited Discounts								
TO	23	Less: Bad Debt								
TO	24	Total Transmission Revenue	0	0	0	0	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	26	**DISTRIBUTION**								
TO	27	Retail Revenue	0	30,017	11,280	14,954	15,399	2,431	(348)	73,733
TO	28	Forfeited Discounts	0	174	65	86	89	14	(2)	426
TO	29	Less: Bad Debt	0	550	207	274	282	45	(6)	1,351
TO	30	Total Distribution Revenue	0	29,640	11,138	14,766	15,206	2,401	(343)	72,808
TO	31	Total Distribution at 5.90% GRT Rate	0	1,749	657	871	897	142	(20)	4,296
TO										
TO	32	TOTAL GROSS RECEIPTS TAX	0	1,749	657	871	897	142	(20)	4,296
TO										
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES	0	2,060	773	970	1,191	150	43	5,187
TO										
TO	36	**TOTAL TAXES OTHER THAN INCOME**	0	2,060	773	970	1,191	150	43	5,187
TO										

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
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TO	1	**OTHER OPERATING EXPENSES**								
TO										
TO	2	**TAXES OTHER THAN INCOME TAXES**								
TO	3	**GENERAL TAXES**								
TO	4	PURTA Taxes	0	0	0	0	0	0	0	0
TO	5	Capital Stock	0	0	0	0	0	0	0	0
TO	6	Payroll Related	0	0	0	1	17	0	0	18
TO	7	Other Property Basis Adjustment (CIAC/ICM) - Federal	0	0	0	0	0	0	0	0
TO	8	Other Property Basis Adjustment (CIAC/ICM) - State	0	0	0	0	0	0	0	0
TO	9	PA & Local Use Tax	0	0	0	0	1	0	(0)	1
TO	10	PA Property Tax	0	0	0	1	0	0	0	1
TO	11	PA Corporate LoanTax	0	0	0	0	0	0	0	0
TO	12	Total General Taxes	0	0	0	2	17	0	0	20
TO										
TO										
TO	13	**GROSS RECEIPTS TAX**								
TO										
TO	14	**PURCHASED POWER**								
TO	15	Retail Revenue	0	0	0	0	0	0	0	0
TO	16	Forfeited Discounts								
TO	17	Less: Bad Debt								
TO	18	Total Purchased Power Revenue	0	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	20	**TRANSMISSION**								
TO	21	Retail Revenue	0	0	0	0	0	0	0	0
TO	22	Forfeited Discounts								
TO	23	Less: Bad Debt								
TO	24	Total Transmission Revenue	0	0	0	0	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	26	**DISTRIBUTION**								
TO	27	Retail Revenue	0	0	28	341	890	16	(15)	1,260
TO	28	Forfeited Discounts	0	0	0	0	0	0	(0)	0
TO	29	Less: Bad Debt	0	0	0	0	1	0	(0)	2
TO	30	Total Distribution Revenue	0	0	28	341	889	16	(15)	1,259
TO	31	Total Distribution at 5.90% GRT Rate	0	0	2	20	52	1	(1)	74
TO										
TO	32	TOTAL GROSS RECEIPTS TAX	0	0	2	20	52	1	(1)	74
TO										
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES	0	0	2	22	70	1	(1)	94
TO										
TO	36	**TOTAL TAXES OTHER THAN INCOME**	0	0	2	22	70	1	(1)	94
TO										

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
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D										
TO	1	**OTHER OPERATING EXPENSES**								
TO										
TO	2	**TAXES OTHER THAN INCOME TAXES**								
TO	3	**GENERAL TAXES**								
TO	4	PURTA Taxes	0	0	0	0	0	0	0	0
TO	5	Capital Stock	0	0	0	0	0	0	0	0
TO	6	Payroll Related	0	0	0	16	137	0	1	155
TO	7	Other Property Basis Adjustment (CIAC/ICM) - Federal	0	0	0	0	0	0	0	0
TO	8	Other Property Basis Adjustment (CIAC/ICM) - State	0	0	0	0	0	0	0	0
TO	9	PA & Local Use Tax	0	0	0	2	4	0	(0)	7
TO	10	PA Property Tax	0	0	2	10	1	0	0	12
TO	11	PA Corporate LoanTax	0	0	0	0	0	0	0	0
TO	12	Total General Taxes	0	0	2	28	143	0	1	174
TO										
TO										
TO	13	**GROSS RECEIPTS TAX**								
TO										
TO	14	**PURCHASED POWER**								
TO	15	Retail Revenue	0	0	0	0	0	0	0	0
TO	16	Forfeited Discounts								
TO	17	Less: Bad Debt								
TO	18	Total Purchased Power Revenue	0	0	0	0	0	0	0	0
TO	19	Total Purchased Power at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	20	**TRANSMISSION**								
TO	21	Retail Revenue	0	0	0	0	0	0	0	0
TO	22	Forfeited Discounts								
TO	23	Less: Bad Debt								
TO	24	Total Transmission Revenue	0	0	0	0	0	0	0	0
TO	25	Total Transmission at 5.90% GRT Rate	0	0	0	0	0	0	0	0
TO										
TO	26	**DISTRIBUTION**								
TO	27	Retail Revenue	0	0	196	4,218	7,205	534	(466)	11,687
TO	28	Forfeited Discounts	0	0	0	2	3	0	(0)	5
TO	29	Less: Bad Debt	0	0	0	6	11	1	(1)	17
TO	30	Total Distribution Revenue	0	0	196	4,214	7,198	533	(466)	11,675
TO	31	Total Distribution at 5.90% GRT Rate	0	0	12	249	425	31	(27)	689
TO										
TO	32	TOTAL GROSS RECEIPTS TAX	0	0	12	249	425	31	(27)	689
TO										
TO	33	TOTAL PURCHASED POWER TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	34	TOTAL TRANSMISSION TOIT EXPENSES	0	0	0	0	0	0	0	0
TO	35	TOTAL DISTRIBUTION TOIT EXPENSES	0	0	14	277	567	32	(27)	863
TO										
TO	36	**TOTAL TAXES OTHER THAN INCOME**	0	0	14	277	567	32	(27)	863
TO										

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
TO										
TO										
TO										
TO										
TO										
TO										
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**								
TI										
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES	0	259,065	16,993	60,361	165,468	38,880	22,832	563,600
TI	3	LESS:								
TI	4	OPERATION & MAINTAINENCE EXPENSE	0	103,651	3,474	12,336	131,996	35,307	18,842	305,605
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE	0	46,065	5,256	40,255	9,156	418	1,662	102,812
TI	6	TAXES OTHER THAN INCOME TAXES	0	17,155	1,097	3,777	12,528	2,369	1,630	38,556
TI	7	NET OPERATING INCOME BEFORE TAXES	0	92,194	7,167	3,993	11,789	786	699	116,628
TI	8	LESS:								
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	35,034	3,117	2,081	3,992	264	285	44,773
TI										
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**	0	57,160	4,049	1,913	7,797	522	414	71,855
TI										
TI										
TI	11	**CALCULATION OF PA STATE INCOME TAXES**								
TI	12	BASE TAXABLE INCOME	0	57,160	4,049	1,913	7,797	522	414	71,855
TI	13	LESS:								
TI	14	State Tax Depreciation (Over) Under Book	0	(7,075)	(1,141)	(1,152)	(173)	(8)	(83)	(9,632)
TI	15	Other Adjustment (state calc.)	0	14,119	2,277	2,300	345	16	165	19,222
TI	16	Repair Allowance Deduction	0	50,024	8,069	8,147	1,222	56	585	68,102
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME	0	92	(5,155)	(7,382)	6,403	459	(253)	(5,836)
TI	18	NOL Utilization	0	5,179	835	844	127	6	61	7,051
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**	0	368	(302)	(457)	456	32	(13)	85
TI	20	**PLUS:**								
TI	21	**DEFERRED STATE INCOME TAXES**								
TI	22	State Deferred Taxes	0	7,119	1,148	1,159	174	8	83	9,692
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RATE**	0	498	80	81	12	1	6	677
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**	0	866	(222)	(376)	469	33	(8)	762
TI										
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**								
TI	26	BASE TAXABLE INCOME	0	57,160	4,049	1,913	7,797	522	414	71,855
TI	27	LESS:								
TI	28	PA State Income Taxes	0	368	(302)	(457)	456	32	(13)	85
TI	29	Federal Tax Depreciation (Over) Under Book	0	(5,921)	(955)	(964)	(145)	(7)	(69)	(8,060)
TI	30	Other Adjustment (federal calc.)	0	15,907	2,566	2,591	389	18	186	21,656
TI	31	Repair Allowance Deduction	0	50,024	8,069	8,147	1,222	56	585	68,102
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME	0	(3,218)	(5,328)	(7,404)	5,874	423	(274)	(9,927)
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	(676)	(1,119)	(1,555)	1,234	89	(57)	(2,085)
TI	34	**PLUS:**								
TI	35	**DEFERRED FEDERAL INCOME TAXES**								
TI	36	Federal Deferred Taxes	0	21,149	3,411	3,444	517	24	247	28,791
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	4,441	716	723	108	5	52	6,046
TI	38	**LESS:**								
TI	39	**OTHER TAX ADJUSTMENTS**								
TI	40	Electric Plant	0	0	0	0	0	0	0	0
TI	41	Common Plant	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	(0)	(3)	(0)	(0)	(0)	(0)	(0)	(3)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**	0	3,768	(402)	(831)	1,342	94	(6)	3,965
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**	0	4,634	(624)	(1,207)	1,811	127	(13)	4,727
TI										
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
TI										

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
TO										
TO										
TO										
TO										
TO										
TO										
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**								
TI										
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES	0	32,626	1,952	9,345	25,297	6,039	3,450	78,708
TI	3	LESS:								
TI	4	OPERATION & MAINTAINENCE EXPENSE	0	16,048	526	2,033	20,900	5,538	2,949	47,995
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE	0	7,183	820	6,523	1,443	65	259	16,294
TI	6	TAXES OTHER THAN INCOME TAXES	0	2,223	131	584	1,922	366	247	5,473
TI	7	NET OPERATING INCOME BEFORE TAXES	0	7,170	476	204	1,032	70	(5)	8,947
TI	8	LESS:								
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	5,453	485	337	630	42	12	6,959
TI										
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**	0	1,718	(9)	(134)	402	28	(17)	1,988
TI										
TI										
TI	11	**CALCULATION OF PA STATE INCOME TAXES**								
TI	12	BASE TAXABLE INCOME	0	1,718	(9)	(134)	402	28	(17)	1,988
TI	13	LESS:								
TI	14	State Tax Depreciation (Over) Under Book	0	(1,103)	(178)	(187)	(27)	(1)	(13)	(1,509)
TI	15	Other Adjustment (state calc.)	0	2,202	355	373	54	2	26	3,012
TI	16	Repair Allowance Deduction	0	7,801	1,258	1,320	193	9	91	10,672
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME	0	(7,182)	(1,444)	(1,640)	182	18	(121)	(10,187)
TI	18	NOL Utilization	0	808	130	137	20	1	9	1,105
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**	0	(446)	(92)	(105)	14	1	(8)	(635)
TI	20	**PLUS:**								
TI	21	**DEFERRED STATE INCOME TAXES**								
TI	22	State Deferred Taxes	0	1,110	179	188	27	1	13	1,519
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RATE**	0	78	13	13	2	0	1	106
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**	0	(368)	(79)	(92)	16	1	(7)	(529)
TI										
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**								
TI	26	BASE TAXABLE INCOME	0	1,718	(9)	(134)	402	28	(17)	1,988
TI	27	LESS:								
TI	28	PA State Income Taxes	0	(446)	(92)	(105)	14	1	(8)	(635)
TI	29	Federal Tax Depreciation (Over) Under Book	0	(923)	(149)	(156)	(23)	(1)	(11)	(1,263)
TI	30	Other Adjustment (federal calc.)	0	2,481	400	420	61	3	29	3,393
TI	31	Repair Allowance Deduction	0	7,801	1,258	1,320	193	9	91	10,672
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME	0	(7,195)	(1,426)	(1,612)	157	16	(119)	(10,180)
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	(1,511)	(300)	(339)	33	3	(25)	(2,138)
TI	34	**PLUS:**								
TI	35	**DEFERRED FEDERAL INCOME TAXES**								
TI	36	Federal Deferred Taxes	0	3,298	532	558	81	4	39	4,512
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	693	112	117	17	1	8	947
TI	38	**LESS:**								
TI	39	**OTHER TAX ADJUSTMENTS**								
TI	40	Electric Plant	0	0	0	0	0	0	0	0
TI	41	Common Plant	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	(0)	(0)	0	0	(0)	(0)	0	(0)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**	0	(818)	(188)	(221)	50	4	(17)	(1,190)
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**	0	(1,186)	(267)	(313)	66	6	(24)	(1,719)
TI										
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
TI										

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
TO										
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TO										
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**								
TI										
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES	0	30,719	11,840	15,228	15,496	2,446	118	75,847
TI	3	LESS:								
TI	4	OPERATION & MAINTAINENCE EXPENSE	0	11,427	2,127	2,836	12,155	2,213	2,081	32,838
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE	0	5,312	3,515	10,187	859	22	192	20,087
TI	6	TAXES OTHER THAN INCOME TAXES	0	2,060	773	970	1,191	150	43	5,187
TI	7	NET OPERATING INCOME BEFORE TAXES	0	11,920	5,425	1,235	1,292	61	(2,198)	17,734
TI	8	LESS:								
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	4,097	2,104	551	400	19	(658)	6,514
TI										
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**	0	7,822	3,321	684	892	42	(1,541)	11,221
TI										
TI										
TI	11	**CALCULATION OF PA STATE INCOME TAXES**								
TI	12	BASE TAXABLE INCOME	0	7,822	3,321	684	892	42	(1,541)	11,221
TI	13	LESS:								
TI	14	State Tax Depreciation (Over) Under Book	0	(817)	(763)	(292)	(16)	(0)	(10)	(1,898)
TI	15	Other Adjustment (state calc.)	0	1,630	1,523	582	32	1	19	3,788
TI	16	Repair Allowance Deduction	0	5,776	5,396	2,062	115	3	67	13,419
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME	0	1,233	(2,836)	(1,668)	761	39	(1,618)	(4,088)
TI	18	NOL Utilization	0	598	559	213	12	0	7	1,389
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**	0	128	(159)	(102)	54	3	(113)	(189)
TI	20	**PLUS:**								
TI	21	**DEFERRED STATE INCOME TAXES**								
TI	22	State Deferred Taxes	0	822	768	293	16	0	10	1,910
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RATE**	0	57	54	21	1	0	1	133
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**	0	185	(105)	(81)	55	3	(112)	(55)
TI										
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**								
TI	26	BASE TAXABLE INCOME	0	7,822	3,321	684	892	42	(1,541)	11,221
TI	27	LESS:								
TI	28	PA State Income Taxes	0	128	(159)	(102)	54	3	(113)	(189)
TI	29	Federal Tax Depreciation (Over) Under Book	0	(684)	(639)	(244)	(14)	(0)	(8)	(1,588)
TI	30	Other Adjustment (federal calc.)	0	1,837	1,716	656	36	1	21	4,267
TI	31	Repair Allowance Deduction	0	5,776	5,396	2,062	115	3	67	13,419
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME	0	765	(2,994)	(1,688)	700	36	(1,509)	(4,689)
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	161	(629)	(354)	147	8	(317)	(985)
TI	34	**PLUS:**								
TI	35	**DEFERRED FEDERAL INCOME TAXES**								
TI	36	Federal Deferred Taxes	0	2,442	2,281	872	48	1	29	5,673
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	513	479	183	10	0	6	1,191
TI	38	**LESS:**								
TI	39	**OTHER TAX ADJUSTMENTS**								
TI	40	Electric Plant	0	0	0	0	0	0	0	0
TI	41	Common Plant	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	(0)	(0)	(0)	(0)	(0)	(0)	0	(1)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**	0	674	(149)	(171)	157	8	(311)	207
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**	0	859	(255)	(252)	212	11	(423)	152
TI										
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
TI										

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
TO										
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TO										
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TO										
TO										
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**								
TI										
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES	0	0	29	346	891	16	(14)	1,268
TI	3	LESS:								
TI	4	OPERATION & MAINTAINENCE EXPENSE	0	0	5	59	688	15	5	771
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE	0	0	8	233	51	0	0	293
TI	6	TAXES OTHER THAN INCOME TAXES	0	0	2	22	70	1	(1)	94
TI	7	NET OPERATING INCOME BEFORE TAXES	0	0	14	31	82	0	(18)	109
TI	8	LESS:								
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	5	12	23	0	(5)	36
TI										
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**	0	0	9	19	58	0	(13)	74
TI										
TI										
TI	11	**CALCULATION OF PA STATE INCOME TAXES**								
TI	12	BASE TAXABLE INCOME	0	0	9	19	58	0	(13)	74
TI	13	LESS:								
TI	14	State Tax Depreciation (Over) Under Book	0	0	(2)	(7)	(1)	(0)	(0)	(9)
TI	15	Other Adjustment (state calc.)	0	0	4	13	2	0	0	19
TI	16	Repair Allowance Deduction	0	0	13	47	7	0	0	67
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME	0	0	(5)	(35)	51	0	(13)	(3)
TI	18	NOL Utilization	0	0	1	5	1	0	0	7
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**	0	0	(0)	(2)	4	0	(1)	0
TI	20	**PLUS:**								
TI	21	**DEFERRED STATE INCOME TAXES**								
TI	22	State Deferred Taxes	0	0	2	7	1	0	0	10
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	1
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**	0	0	(0)	(2)	4	0	(1)	1
TI										
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**								
TI	26	BASE TAXABLE INCOME	0	0	9	19	58	0	(13)	74
TI	27	LESS:								
TI	28	PA State Income Taxes	0	0	(0)	(2)	4	0	(1)	0
TI	29	Federal Tax Depreciation (Over) Under Book	0	0	(2)	(6)	(1)	(0)	(0)	(8)
TI	30	Other Adjustment (federal calc.)	0	0	4	15	2	0	0	21
TI	31	Repair Allowance Deduction	0	0	13	47	7	0	0	67
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME	0	0	(6)	(36)	47	0	(12)	(7)
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	0	(1)	(7)	10	0	(3)	(1)
TI	34	**PLUS:**								
TI	35	**DEFERRED FEDERAL INCOME TAXES**								
TI	36	Federal Deferred Taxes	0	0	5	20	3	0	0	28
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	0	1	4	1	0	0	6
TI	38	**LESS:**								
TI	39	**OTHER TAX ADJUSTMENTS**								
TI	40	Electric Plant	0	0	0	0	0	0	0	0
TI	41	Common Plant	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**	0	0	(0)	(3)	10	0	(3)	4
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**	0	0	(0)	(5)	14	0	(4)	5
TI										
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
TI										

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
TO										
TO										
TO										
TO										
TO										
TO										
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**								
TI										
TI	2	TOTAL DISTRIBUTION OPERATING REVENUES	0	0	205	4,274	7,213	534	(458)	11,767
TI	3	LESS:								
TI	4	OPERATION & MAINTAINENCE EXPENSE	0	0	35	738	5,606	494	35	6,908
TI	5	DEPRECIATION AND AMORTIZATION EXPENSE	0	0	63	2,911	417	0	3	3,395
TI	6	TAXES OTHER THAN INCOME TAXES	0	0	14	277	567	32	(27)	863
TI	7	NET OPERATING INCOME BEFORE TAXES	0	0	94	347	622	7	(470)	601
TI	8	LESS:								
TI	9	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	38	160	198	2	(146)	253
TI										
TI	10	**BASE TAXABLE DISTRIBUTION INCOME**	0	0	56	187	424	5	(324)	349
TI										
TI										
TI	11	**CALCULATION OF PA STATE INCOME TAXES**								
TI	12	BASE TAXABLE INCOME	0	0	56	187	424	5	(324)	349
TI	13	LESS:								
TI	14	State Tax Depreciation (Over) Under Book	0	0	(14)	(83)	(8)	(0)	(0)	(105)
TI	15	Other Adjustment (state calc.)	0	0	27	166	16	0	0	209
TI	16	Repair Allowance Deduction	0	0	96	589	56	0	0	742
TI	17	PA STATE TAXABLE DISTRIBUTION INCOME	0	0	(54)	(485)	361	5	(324)	(498)
TI	18	NOL Utilization	0	0	10	61	6	0	0	77
TI	19	**PA STATE INCOME TAXES AT 6.99% TAX RATE**	0	0	(3)	(30)	26	0	(23)	(29)
TI	20	**PLUS:**								
TI	21	**DEFERRED STATE INCOME TAXES**								
TI	22	State Deferred Taxes	0	0	14	84	8	0	0	106
TI	23	**DEFERRED STATE INCOME TAXES AT 6.99% TAX RATE**	0	0	1	6	1	0	0	7
TI	24	**TOTAL DISTRIBUTION STATE INCOME TAX EXPENSE**	0	0	(2)	(24)	26	0	(23)	(22)
TI										
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**								
TI	26	BASE TAXABLE INCOME	0	0	56	187	424	5	(324)	349
TI	27	LESS:								
TI	28	PA State Income Taxes	0	0	(3)	(30)	26	0	(23)	(29)
TI	29	Federal Tax Depreciation (Over) Under Book	0	0	(11)	(70)	(7)	(0)	(0)	(88)
TI	30	Other Adjustment (federal calc.)	0	0	31	187	18	0	0	236
TI	31	Repair Allowance Deduction	0	0	96	589	56	0	0	742
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME	0	0	(56)	(490)	332	5	(302)	(512)
TI	33	**FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	0	(12)	(103)	70	1	(63)	(108)
TI	34	**PLUS:**								
TI	35	**DEFERRED FEDERAL INCOME TAXES**								
TI	36	Federal Deferred Taxes	0	0	41	249	24	0	0	314
TI	37	**DEFERRED FEDERAL INCOME TAXES AT 21.00% TAX RATE**	0	0	9	52	5	0	0	66
TI	38	**LESS:**								
TI	39	**OTHER TAX ADJUSTMENTS**								
TI	40	Electric Plant	0	0	0	0	0	0	0	0
TI	41	Common Plant	0	0	0	0	0	0	0	0
TI	42	Amortization of Investment Tax Credit	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)
TI	43	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**	0	0	(3)	(51)	75	1	(63)	(42)
TI	44	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**	0	0	(5)	(74)	101	1	(86)	(64)
TI										
TI	45	**DEVELOPMENT OF INCOME TAXES CONTINUED**								
TI										

Sch.	LineNo.	Description	Residential CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**								
TI	47	PURCHASED POWER OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	48	LESS:								
TI	49	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	52	LESS:								
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**	0	0	0	0	0	0	0	0
TI	55	LESS:								
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	57	EQUALS:								
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL	0	0	0	0	0	0	0	0
TI										
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**								
TI	61	TRANSMISSION OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	62	LESS:								
TI	63	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	66	LESS:								
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**	0	0	0	0	0	0	0	0
TI	69	LESS:								
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	71	EQUALS:								
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI										
TI	73	**TOTAL PA INCOME TAX EXPENSE**	0	866	(222)	(376)	469	33	(8)	762
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**	0	3,768	(402)	(831)	1,342	94	(6)	3,965
TI	75	**TOTAL INCOME TAX EXPENSE**	0	4,634	(624)	(1,207)	1,811	127	(13)	4,727
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RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**								
RRW										
RRW	2	Present Rates								
RRW										
RRW	3	Rate Base ($)	0	1,571,025	139,781	93,316	179,026	11,833	12,778	2,007,759
RRW	4	Net Operating Income at Present Rates ($)	0	87,560	7,791	5,201	9,978	659	712	111,901
RRW	5	Rate of Return at Present Rates	114.36%	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%	5.57%
RRW	6	Relative Rate of Return	1.26	1.03	1.00	1.02	1.04	1.05	0.53	1.02
RRW	7	Sales Revenue at Present Rates ($)	0	251,506	16,062	58,920	163,443	38,421	18,565	546,917
RRW	8	Revenue at Present Rates ($/KWH)	$0.0000	$0.0222	$0.0014	$0.0052	$0.0144	$0.0034	$0.0016	$0.0482

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**								
TI	47	PURCHASED POWER OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	48	LESS:								
TI	49	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	52	LESS:								
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**	0	0	0	0	0	0	0	0
TI	55	LESS:								
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	57	EQUALS:								
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL	0	0	0	0	0	0	0	0
TI										
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**								
TI	61	TRANSMISSION OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	62	LESS:								
TI	63	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	66	LESS:								
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**	0	0	0	0	0	0	0	0
TI	69	LESS:								
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	71	EQUALS:								
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI										
TI	73	**TOTAL PA INCOME TAX EXPENSE**	0	(368)	(79)	(92)	16	1	(7)	(529)
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**	0	(818)	(188)	(221)	50	4	(17)	(1,190)
TI	75	**TOTAL INCOME TAX EXPENSE**	0	(1,186)	(267)	(313)	66	6	(24)	(1,719)
TI										
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RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**								
RRW										
RRW	2	Present Rates								
RRW										
RRW	3	Rate Base ($)	0	244,511	21,750	15,132	28,267	1,873	547	312,079
RRW	4	Net Operating Income at Present Rates ($)	0	8,357	743	517	966	64	19	10,666
RRW	5	Rate of Return at Present Rates	104.20%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%	3.42%
RRW	6	Relative Rate of Return	1.15	0.63	0.61	0.63	0.64	0.64	0.32	0.63
RRW	7	Sales Revenue at Present Rates ($)	0	31,483	1,812	9,100	24,943	5,957	2,781	76,077
RRW	8	Revenue at Present Rates ($/KWH)	$0.0000	$0.0112	$0.0006	$0.0032	$0.0089	$0.0021	$0.0010	$0.0271

Sch.	LineNo.	Description	General Service CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**								
TI	47	PURCHASED POWER OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	48	LESS:								
TI	49	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	52	LESS:								
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**	0	0	0	0	0	0	0	0
TI	55	LESS:								
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	57	EQUALS:								
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL	0	0	0	0	0	0	0	0
TI										
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**								
TI	61	TRANSMISSION OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	62	LESS:								
TI	63	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	66	LESS:								
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**	0	0	0	0	0	0	0	0
TI	69	LESS:								
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	71	EQUALS:								
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI										
TI	73	**TOTAL PA INCOME TAX EXPENSE**	0	185	(105)	(81)	55	3	(112)	(55)
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**	0	674	(149)	(171)	157	8	(311)	207
TI	75	**TOTAL INCOME TAX EXPENSE**	0	859	(255)	(252)	212	11	(423)	152
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RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**								
RRW										
RRW	2	Present Rates								
RRW										
RRW	3	Rate Base ($)	0	183,743	94,361	24,716	17,930	834	(29,496)	292,088
RRW	4	Net Operating Income at Present Rates ($)	0	11,060	5,680	1,488	1,079	50	(1,776)	17,582
RRW	5	Rate of Return at Present Rates	89.07%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%	6.02%
RRW	6	Relative Rate of Return	0.98	1.11	1.08	1.11	1.12	1.13	0.57	1.10
RRW	7	Sales Revenue at Present Rates ($)	0	30,017	11,280	14,954	15,399	2,431	(348)	73,733
RRW	8	Revenue at Present Rates ($/KWH)	$0.0000	$0.0040	$0.0015	$0.0020	$0.0020	$0.0003	($0.0000)	$0.0098

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**								
TI	47	PURCHASED POWER OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	48	LESS:								
TI	49	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	52	LESS:								
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**	0	0	0	0	0	0	0	0
TI	55	LESS:								
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	57	EQUALS:								
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL	0	0	0	0	0	0	0	0
TI										
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**								
TI	61	TRANSMISSION OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	62	LESS:								
TI	63	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	66	LESS:								
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**	0	0	0	0	0	0	0	0
TI	69	LESS:								
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	71	EQUALS:								
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI										
TI	73	**TOTAL PA INCOME TAX EXPENSE**	0	0	(0)	(2)	4	0	(1)	1
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**	0	0	(0)	(3)	10	0	(3)	4
TI	75	**TOTAL INCOME TAX EXPENSE**	0	0	(0)	(5)	14	0	(4)	5
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RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**								
RRW										
RRW	2	Present Rates								
RRW										
RRW	3	Rate Base ($)	0	0	225	555	1,036	3	(226)	1,593
RRW	4	Net Operating Income at Present Rates ($)	0	0	15	36	67	0	(15)	104
RRW	5	Rate of Return at Present Rates	99.42%	99.42%	6.52%	6.52%	6.52%	6.52%	6.52%	6.52%
RRW	6	Relative Rate of Return	1.10	18.33	1.17	1.20	1.21	1.22	0.61	1.20
RRW	7	Sales Revenue at Present Rates ($)	0	0	28	341	890	16	(15)	1,260
RRW	8	Revenue at Present Rates ($/KWH)	$0.0000	$0.0000	$0.0001	$0.0012	$0.0031	$0.0001	($0.0001)	$0.0044

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
TI	46	**DEVELOPMENT OF PURCHASED POWER TAXES**								
TI	47	PURCHASED POWER OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	48	LESS:								
TI	49	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	50	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	51	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	52	LESS:								
TI	53	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	54	**BASE TAXABLE PURCHASED POWER INCOME**	0	0	0	0	0	0	0	0
TI	55	LESS:								
TI	56	**PA STATE PURCHASED PWR INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	57	EQUALS:								
TI	58	**FEDERAL PURCHASED PWR INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI	59	Additional Purchase Power Expense NOL	0	0	0	0	0	0	0	0
TI										
TI	60	**DEVELOPMENT OF TRANSMISSION TAXES**								
TI	61	TRANSMISSION OPERATING REVENUES	0	0	0	0	0	0	0	0
TI	62	LESS:								
TI	63	OPERATION & MAINTAINENCE EXPENSE	0	0	0	0	0	0	0	0
TI	64	TAXES OTHER THAN INCOME TAXES	0	0	0	0	0	0	0	0
TI	65	NET OPERATING INCOME BEFORE TAXES	0	0	0	0	0	0	0	0
TI	66	LESS:								
TI	67	INTEREST EXPENSE (= Rate Base * 2.23% Weighted Cost of Debt)	0	0	0	0	0	0	0	0
TI	68	**BASE TAXABLE TRANSMISSION INCOME**	0	0	0	0	0	0	0	0
TI	69	LESS:								
TI	70	**PA STATE TRANSMISSION INCOME TAXES AT 6.99% TAX RATE**	0	0	0	0	0	0	0	0
TI	71	EQUALS:								
TI	72	**FEDERAL TRANSMISSION INCOME TAXES AT 21.00% TAX RATE**	0	0	0	0	0	0	0	0
TI										
TI	73	**TOTAL PA INCOME TAX EXPENSE**	0	0	(2)	(24)	26	0	(23)	(22)
TI	74	**TOTAL FEDERAL INCOME TAX EXPENSE**	0	0	(3)	(51)	75	1	(63)	(42)
TI	75	**TOTAL INCOME TAX EXPENSE**	0	0	(5)	(74)	101	1	(86)	(64)
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RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**								
RRW										
RRW	2	Present Rates								
RRW										
RRW	3	Rate Base ($)	0	0	1,692	7,187	8,883	103	(6,537)	11,327
RRW	4	Net Operating Income at Present Rates ($)	0	0	99	422	521	6	(384)	665
RRW	5	Rate of Return at Present Rates	80.64%	80.64%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%
RRW	6	Relative Rate of Return	0.89	14.87	1.06	1.08	1.09	1.10	0.55	1.08
RRW	7	Sales Revenue at Present Rates ($)	0	0	196	4,218	7,205	534	(466)	11,687
RRW	8	Revenue at Present Rates ($/KWH)	$0.0000	$0.0000	$0.0000	$0.0003	$0.0005	$0.0000	($0.0000)	$0.0008

			Residential							
Sch.	LineNo.	Description	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Revenue Required by Component	$ 0	$ 309,153	$ 21,191	$ 62,344	$ 170,012	$ 38,855	$ 19,034	$ 620,590
		Number of Bills	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098	16,177,098
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.11	$ 1.31	$ 3.85	$ 10.51	$ 2.40	$ 1.18	$ 38.36
RRW	9	Revenue Required - $/MO/CUST	$0.00	$15.55	$0.99	$3.64	$10.10	$2.38	$1.15	$33.81
RRW	10	Sales Revenue Required - $/KW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RRW										
RRW	11	Proposed Rate of Return								
RRW										
RRW	12	Proposed Rate of Return	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR	0	126,939	11,294	7,540	14,465	956	1,032	162,227
RRW	14	Sales Revenue Required at Proposed ROR - Distribution	0	309,153	21,191	62,344	170,012	38,855	19,034	620,590
RRW	15	Revenue Deficiency Sales Revenue	0	57,647	5,129	3,424	6,569	434	469	73,673
RRW	16	Percent Increase Required	60.89%	22.92%	31.93%	5.81%	4.02%	1.13%	2.53%	13.47%
RRW	17	Annual Booked kWh Sales	11,346,277	11,346,277	11,346,277	11,346,277	11,346,277	11,346,277	11,346,277	11,346,277
RRW	18	Sales Revenue Required $/KWH	$0.0000	$0.0272	$0.0019	$0.0055	$0.0150	$0.0034	$0.0017	$0.0547
RRW	19	Revenue Deficiency $/KWH	$0.0000	$0.0051	$0.0005	$0.0003	$0.0006	$0.0000	$0.0000	$0.0065
RRW	20	Sales Revenue Req. at Proposed ROR - Energy	0	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Residential Heating CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
		Revenue Required by Component	$ 0	$ 48,172	$ 3,297	$ 10,133	$ 26,873	$ 6,085	$ 2,818	$ 97,377
		Number of Bills	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699	2,522,699
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.10	$ 1.31	$ 4.02	$ 10.65	$ 2.41	$ 1.12	$ 38.60
RRW	9	Revenue Required - $/MO/CUST	$0.00	$12.48	$0.72	$3.61	$9.89	$2.36	$1.10	$30.16
RRW	10	Sales Revenue Required - $/KW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RRW										
RRW	11	Proposed Rate of Return								
RRW										
RRW	12	Proposed Rate of Return	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR	0	19,757	1,757	1,223	2,284	151	44	25,216
RRW	14	Sales Revenue Required at Proposed ROR - Distribution	0	48,172	3,297	10,133	26,873	6,085	2,818	97,377
RRW	15	Revenue Deficiency Sales Revenue	0	16,688	1,484	1,033	1,929	128	37	21,300
RRW	16	Percent Increase Required	96.15%	53.01%	81.91%	11.35%	7.73%	2.15%	1.34%	28.00%
RRW	17	Annual Booked kWh Sales	2,804,983	2,804,983	2,804,983	2,804,983	2,804,983	2,804,983	2,804,983	2,804,983
RRW	18	Sales Revenue Required $/KWH	$0.0000	$0.0172	$0.0012	$0.0036	$0.0096	$0.0022	$0.0010	$0.0347
RRW	19	Revenue Deficiency $/KWH	$0.0000	$0.0059	$0.0005	$0.0004	$0.0007	$0.0000	$0.0000	$0.0076
RRW	20	Sales Revenue Req. at Proposed ROR - Energy	0	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission	0	0	0	0	0	0	0	0

			General Service							
Sch.	LineNo.	Description	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		Revenue Required by Component	$ 0	$ 35,559	$ 14,126	$ 15,699	$ 15,940	$ 2,457	$ (1,238)	$ 82,543
		Number of Bills	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855	1,867,855
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 19.04	$ 7.56	$ 8.41	$ 8.53	$ 1.32	$ (0.66)	$ 44.19
RRW	9	Revenue Required - $/MO/CUST	$0.00	$16.07	$6.04	$8.01	$8.24	$1.30	($0.19)	$39.47
RRW	10	Sales Revenue Required - $/KW	$0.00	$1.20	$0.45	$0.60	$0.62	$0.10	($0.01)	$2.95
RRW										
RRW	11	Proposed Rate of Return								
RRW										
RRW	12	Proposed Rate of Return	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR	0	14,846	7,624	1,997	1,449	67	(2,383)	23,601
RRW	14	Sales Revenue Required at Proposed ROR - Distribution	0	35,559	14,126	15,699	15,940	2,457	(1,238)	82,543
RRW	15	Revenue Deficiency Sales Revenue	0	5,543	2,846	746	541	25	(890)	8,811
RRW	16	Percent Increase Required	59.28%	18.47%	25.23%	4.99%	3.51%	1.04%	255.83%	11.95%
RRW	17	Annual Booked kWh Sales	7,549,351	7,549,351	7,549,351	7,549,351	7,549,351	7,549,351	7,549,351	7,549,351
RRW	18	Sales Revenue Required $/KWH	$0.0000	$0.0047	$0.0019	$0.0021	$0.0021	$0.0003	($0.0002)	$0.0109
RRW	19	Revenue Deficiency $/KWH	$0.0000	$0.0007	$0.0004	$0.0001	$0.0001	$0.0000	($0.0001)	$0.0012
RRW	20	Sales Revenue Req. at Proposed ROR - Energy	0	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	Primary Distribution CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)
		Revenue Required by Component	$ 0	$ 0	$ 33	$ 354	$ 913	$ 16	$ (20)	$ 1,297
		Number of Bills	4,476	4,476	4,476	4,476	4,476	4,476	4,476	4,476
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.47	$ 79.06	$ 204.06	$ 3.55	$ (4.44)	$ 289.71
RRW	9	Revenue Required - $/MO/CUST	$0.00	$0.00	$6.32	$76.22	$198.76	$3.53	($3.28)	$281.56
RRW	10	Sales Revenue Required - $/KW	$0.00	$0.00	$0.04	$0.46	$1.21	$0.02	($0.02)	$1.71
RRW										
RRW	11	Proposed Rate of Return								
RRW										
RRW	12	Proposed Rate of Return	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR	0	0	18	45	84	0	(18)	129
RRW	14	Sales Revenue Required at Proposed ROR - Distribution	0	0	33	354	913	16	(20)	1,297
RRW	15	Revenue Deficiency Sales Revenue	0	0	5	13	24	0	(5)	36
RRW	16	Percent Increase Required	45.10%	45.10%	18.26%	3.72%	2.67%	0.43%	35.22%	2.89%
RRW	17	Annual Booked kWh Sales	288,122	288,122	288,122	288,122	288,122	288,122	288,122	288,122
RRW	18	Sales Revenue Required $/KWH	$0.0000	$0.0000	$0.0001	$0.0012	$0.0032	$0.0001	($0.0001)	$0.0045
RRW	19	Revenue Deficiency $/KWH	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	($0.0000)	$0.0001
RRW	20	Sales Revenue Req. at Proposed ROR - Energy	0	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission	0	0	0	0	0	0	0	0

Sch.	LineNo.	Description	High Tension CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH	Customer Total
(A)	(B)	(C)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)
		Revenue Required by Component	$ 0	$ 0	$ 251	$ 4,451	$ 7,493	$ 537	$ (678)	$ 12,053
		Number of Bills	33,396	33,396	33,396	33,396	33,396	33,396	33,396	33,396
		$/Month/Customer (= Tot. Comp. Base Sales Rev. Req / Number of Bills*1000)	$ 0.00	$ 0.00	$ 7.51	$ 133.27	$ 224.36	$ 16.08	$ (20.29)	$ 360.92
RRW	9	Revenue Required - $/MO/CUST	$0.00	$0.00	$5.87	$126.31	$215.75	$15.98	($13.96)	$349.95
RRW	10	Sales Revenue Required - $/KW	$0.00	$0.00	$0.01	$0.13	$0.22	$0.02	($0.01)	$0.36
RRW										
RRW	11	Proposed Rate of Return								
RRW										
RRW	12	Proposed Rate of Return	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
RRW	13	Return Required for Proposed ROR	0	0	137	581	718	8	(528)	915
RRW	14	Sales Revenue Required at Proposed ROR - Distribution	0	0	251	4,451	7,493	537	(678)	12,053
RRW	15	Revenue Deficiency Sales Revenue	0	0	55	233	287	3	(212)	367
RRW	16	Percent Increase Required	61.75%	61.75%	27.93%	5.51%	3.99%	0.62%	45.38%	3.14%
RRW	17	Annual Booked kWh Sales	13,820,127	13,820,127	13,820,127	13,820,127	13,820,127	13,820,127	13,820,127	13,820,127
RRW	18	Sales Revenue Required $/KWH	$0.0000	$0.0000	$0.0000	$0.0003	$0.0005	$0.0000	($0.0000)	$0.0009
RRW	19	Revenue Deficiency $/KWH	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	($0.0000)	$0.0000
RRW	20	Sales Revenue Req. at Proposed ROR - Energy	0	0	0	0	0	0	0	0
RRW	21	Sales Revenue Req. at Proposed ROR - Transmission	0	0	0	0	0	0	0	0

PECO Exhibit JD-6:
Night Service Rider
Related Costs

Night Service Rider

Line	Description	FERC Account	Lines @ PECO Exhibits JD-1 and JD-3	GS Amount	GS Ratio	PD Amount	PD Ratio	HT Amount	HT Ratio	EP Amount	EP Ratio
1	NS Related Distribution Plant	365,367,368	RBP26,27,36,37,40	1,099,775	45%	28,017	46%	710,418	43%	41,468	43%
2	Total Distribution Plant		RBP46	$ 2,442,467		$ 60,652		$ 1,671,385		$ 96,422	
3	NS Related Distribution O&M	593,594	E49,50	$ 41,585	54%	$ 1,241	58%	$ 28,779	52%	$ 1,680	53%
4	Total Distribution Plant O&M Less A&G		E56	$ 76,648		$ 2,149		$ 55,067		$ 3,189	
5	Customer Accounts O&M	901-910,912,916	E67,73,74	$ 16,363		$ 481		$ 4,539		$ 21	
6	Total Dist. O&M + Customer Account			$ 93,012	45%	$ 2,630	47%	$ 59,606	48%	$ 3,209	52%
7	Total Distribution Revenue @ 8.08%		S60	$ 404,014		$ 11,039		$ 278,904		$ 15,433	
8	Total Distribution Operation Expense Less Depr Less Fed/State Taxes		S49,51,52	$ 153,853		$ 4,442		$ 102,637		$ 5,582	
9	NS Related Operation Expense			$ 68,787		$ 2,096		$ 49,556		$ 2,922	
10	Capital Related Costs @ 8.08%			$ 250,161		$ 6,596		$ 176,267		$ 9,852	
11	NS Related Capital Cost @ 8.08%			$ 112,641		$ 3,047		$ 74,922		$ 4,237	
12	NS Related Capital Plus Expense			$ 181,427		$ 5,143		$ 124,478		$ 7,159	
13	NCP Demand (MW)		JD-2, P.4, Line 10	1,796,705		62,135		2,363,175		137,941	
14	Monthly NS Cost ($/kW)			$ 8.41		$ 6.90		$ 4.39		$ 4.32	

PECO Exhibit JD-7:
Development of External Allocation Factors

Table of External Allocators

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External Allocator Values by Class

Schedule-1

Line	Units	Allocator Names	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	MWh	Energy @ Meter	36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
2	MWh	Energy @ Generation	39,254,841	12,516,078	3,094,177	8,327,689	312,353	14,368,786	485,555	150,203
3	MWh	Energy @ Generation-CI	23,008,827			8,327,689	312,353	14,368,786		
4	MW	Demand Transmission (1CP)	8,379,496	4,007,744	584,624	1,606,611	55,471	2,044,013	75,331	5,701
5	MW	Demand Distribution Primary High Tension (NCP)	9,667,374	4,030,305	1,232,991	1,796,705	62,135	2,363,175	137,941	44,122
6	MW	Demand Distribution Primary (NCP)	7,166,258	4,030,305	1,232,991	1,796,705	62,135	-	-	44,122
7	MW	Demand Distribution Secondary (NCP)	7,104,123	4,030,305	1,232,991	1,796,705	-	-	-	44,122
8	KW	Billed Capacity	59,799,850	-	-	24,977,660	736,436	32,343,098	1,742,655	0
9	#	Bills	20,756,557	16,177,098	2,522,699	1,867,855	4,476	33,396	465	150,568
10	#	Customers	1,729,713	1,348,092	210,225	155,655	373	2,783	39	12,547
11	#	Customers-LCI	3,156				373	2,783		
12	#	Customers-Res	1,558,316	1,348,092	210,225					
13	#	Customers-Excl Ind	1,713,971	1,348,092	210,225	155,655				
14	#	Customers-CI	158,811			155,655	373	2,783		
15	#	Location Secondary	1,775,975	1,348,092	210,225	155,655				62,004
16	$000	Services Cost	4,005,702	2,178,996	339,798	1,457,360	3,492	26,057	-	-
17	$000	Meters Cost	391,670	262,153	42,483	66,343	1,518	18,960	214	-
18	$000	Purchased Power	1,612,994	1,040,649	259,956	228,750	1,695	81,286	-	658
19	$000	Write-Offs	140,276	101,751	22,593	15,069	29	825	0	9
20	%	Customer Records and Collection Expenses (Acct903)	100.00%	76.40%	12.04%	7.12%	0.44%	3.57%	0.02%	0.40%
21	%	Customer Assistance Expenses (Acct908)	100.00%	82.57%	12.88%	4.22%	0.01%	0.08%	0.00%	0.25%
22	%	Demonstrating and Selling Expense / Miscellaneous Sales Expense (Accts 912/916)	100.00%	0.00%	0.00%	36.19%	1.36%	62.45%	0.00%	0.00%
23	%	AR Over60-Day	100.00%	61.74%	11.94%	15.67%	0.41%	9.83%	0.41%	0.00%
24	%	Customer Deposit	100.00%	32.84%	7.29%	49.78%	0.35%	9.74%	0.00%	0.00%
25	%	Purchase of Receivables	100.00%	23.03%	5.69%	36.67%	0.70%	33.63%	0.00%	0.28%
26	%	Lighting	100.00%							100%
27	Minutes	Call Center	12,205,196	10,052,792	1,581,308	571,096				

External Allocator Values by Function

Schedule-2

Line	Accounts/Functional Allocation Factors	Total	Primary-HT	Primary	Secondary
1	Overhead Conductors & Devices (Acct 365)	100.00%	47.25%	24.93%	27.83%
2	Underground Conductors & Devices (Acct 367)	100.00%	60.88%	14.93%	24.19%
3					

Schedule-3

Conductors - Functional
As of December 31, 1999

Line	Account By Region	Total Conductor Miles	Total Cost	Primary Cost	Secondary Cost
Line	**Overhead Conductors and Devices- Acct 365**				
1	North Philadelphia	11,738	$39,304,750	$18,109,116	$21,195,635
2	South Philadelphia	4,822	17,960,601	8,892,979	9,067,622
3	Chester	9,937	48,937,047	40,674,940	8,262,107
4	Montgomery	15,183	60,943,742	48,523,974	12,419,768
5	Bucks / some Montgomery	9,938	44,172,132	35,838,311	8,333,822
6	Delaware / some Chester	9,672	48,937,814	35,732,133	13,205,681
7	York	1,441	4,703,314	3,461,050	1,242,265
8	Total	62,731	$264,959,401	$191,232,501	$73,726,900
9					
10	Cost		100.0%	72.2%	27.8%
11					
12					
13	**Underground Conductors- Acct 367**				
14	North Philadelphia	4,497	$118,821,520	$103,051,929	$15,769,591
15	South Philadelphia	2,878	61,118,575	46,100,768	15,017,807
16	Chester	3,807	54,670,691	38,932,557	15,738,135
17	Montgomery	3,173	52,252,889	36,357,564	15,895,325
18	Bucks / some Montgomery	3,954	57,940,433	40,152,597	17,787,836
19	Delaware / some Chester	2,322	29,301,818	19,034,169	10,267,649
20	York	10	113,033	70,567	42,466
21	Total	20,640	$374,218,959	$283,700,149	$90,518,810
22					
23	Cost		100.0%	75.8%	24.2%
24					

Schedule-4

Conductors - Primary
As of December 31, 2025

Line	System Voltage	Class	Overhead Conductor Wire_Miles	Underground Conductor Wire_Miles
1	2.4	Primary	48	130
2	4	Primary	10,185	3,272
3	13	HT	9,641	8,197
4	34	HT	9,756	5,670
5			29,630	17,269
6				
7		Primary	10,233	3,402
8		HT	19,397	13,867
9			29,630	17,269
10				
11		Primary	34.5%	19.7%
12		HT	65.5%	80.3%
13			100.0%	100.0%
14				

Service Costs

Schedule-5

Line	Rate Class	Customer Numbers	Average Services Cost	Total Services Cost	Ratio
1	Residential	1,348,092	$ 1,616	$ 2,178,995,594	54.4%
2	Residential Heating	210,225	$ 1,616	$ 339,798,276	8.5%
3	General Service	155,655	$ 9,363	$ 1,457,359,595	36.4%
4	Primary Distribution	373	$ 9,363	$ 3,492,317	0.1%
5	High Tension	2,783	$ 9,363	$ 26,056,616	0.7%
6	Electric Propulsion	39			
7	Lighting	12,547			
8		1,729,713		$ 4,005,702,398	100%

Meter Costs **(a)**

Schedule-6

Line	Rate Class	Average Cost (b)	Customers	Meter Costs	Ratio
1	Residential	$ 194	1,348,092	$ 262,152,798	66.9%
2	Residential Heating	$ 202	210,225	$ 42,483,037	10.8%
3	General Service	$ 426	155,655	$ 66,343,330	16.9%
4	Primary Distribution	$ 4,069	373	$ 1,517,561	0.4%
5	High Tension	$ 6,813	2,783	$ 18,959,686	4.8%
6	Electric Propulsion	$ 5,512	39	$ 213,600	0.1%
7	Lighting		12,547		
8	Total		1,729,713	$ 391,670,011	100%

(a) Meter counts as of November 2025
(b) Includes cost of material and labor

Customer Deposits

Schedule-7

Thirteen Months Ended December 31, 2025

Line	Activity	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Customer Deposit	100.0%	32.8%	7.3%	49.8%	0.3%	9.7%	0.0%	0.0%
2		100.0%	32.8%	7.3%	49.8%	0.3%	9.7%	0.0%	0.0%

Schedule-8

Customer Records and Collection Expenses (Account 903)
For Year 2024

Line	Activity	Total	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Billing	35,016,654	Bills	35,016,654	27,291,032	4,255,835	3,151,102	7,551	56,340	784	254,010
2	CAP Rates	9,227,494	Customers-Res	9,227,494	7,982,657	1,244,836	-	-	-	-	-
3	Recoveries	4,536,525	AR Over60-Day	4,536,525	2,800,728	541,506	711,027	18,786	446,067	18,411	-
4	Call Center	21,092,345	Call Center	21,092,345	17,372,680	2,732,730	986,936	-	-	-	-
5	C&MS	16,353,373	Customers	16,353,373	12,745,376	1,987,547	1,471,618	3,526	26,312	366	118,627
6	ESO Activities	3,498,436	Customers-LCI	3,498,436	-	-	-	413,472	3,084,965	-	-
7	Low Income	1,725,227	Customers-Res	1,725,227	1,492,485	232,742	-	-	-	-	-
8	Field Vendor	3,337,705	Customers	3,337,705	2,601,317	405,656	300,356	720	5,370	75	24,212
9	Care Center	4,891,495	Customers-Excl Ind	4,891,495	3,847,313	599,960	444,222	-	-	-	-
10	Other	1,675,481	Customers	1,675,481	1,305,824	203,634	150,774	361	2,696	38	12,154
11		101,354,736		101,354,736	77,439,412	12,204,446	7,216,036	444,416	3,621,749	19,674	409,003
12	**Acct903 Allocator**			**100.00%**	**76.40%**	**12.04%**	**7.12%**	**0.44%**	**3.57%**	**0.02%**	**0.40%**

Schedule-9

Customer Assistance Expenses (Account 908)
For Year 2024

Line	Activity	Total	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Residential Marketing	680,320	Customers-Res	680,320	588,542	91,779	-	-	-	-	-
2	C&I Marketing	158,653	Customers-CI	158,653	-	-	155,500	373	2,780	-	-
3	Marketing - General	1,696,674	Customers	1,696,674	1,322,341	206,209	152,681	366	2,730	38	12,308
4	LIURP	8,117,470	Customers-Res	8,117,470	7,022,381	1,095,089	-	-	-	-	-
5	Other	2,952,806	Customers	2,952,806	2,301,337	358,877	265,719	637	4,751	66	21,420
6		13,605,923		13,605,923	11,234,602	1,751,953	573,900	1,375	10,261	104	33,727
7	**Acct908 Allocator**			**100.00%**	**82.57%**	**12.88%**	**4.22%**	**0.01%**	**0.08%**	**0.00%**	**0.25%**

Schedule-10

Demonstrating and Selling Expense / Miscellaneous Sales Expense
For Year 2024

Line	Activity	Total	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	C&I Expense	252,289	Energy @ Generation-CI	252,289	-	-	91,312	3,425	157,552	-	-
2		252,289		252,289	-	-	91,312	3,425	157,552	-	-
3	**Acct912 and 916 Allocator**			**100.00%**	**0.00%**	**0.00%**	**36.19%**	**1.36%**	**62.45%**	**0.00%**	**0.00%**

Write-Offs

Schedule-11 **Net Write-Offs from 2023 to 2025**

Line	Rate Class	Net Write-Offs
1	Residential	$ 101,750,661
2	Residential Heating	22,592,877
3	General Service	15,068,814
4	Primary Distribution	29,414
5	High Tension	824,654
6	Electric Propulsion	220
7	Lighting	9,147
8		$ 140,275,788

Schedule-12

Accounts Receivable Over 60-Day
January 2025 to December 2025

Line	Rate Class	Average Over 60-Day	Over 60-Day Allocator	Residential Revenue	% Residential Revenue	LC&I Revenue	% LC&I Revenue
1	Residential	$ 98,253,374	61.7%	$ 1,134,536,371	83.8%		
2	Residential Heating	18,996,767	11.9%	219,356,571	16.2%		
3	General Service	24,943,819	15.7%				
4	Primary Distribution	659,038	0.4%			$ 9,858,771	3.9%
5	High Tension	15,648,640	9.8%			234,093,184	92.3%
6	Electric Propulsion	645,889	0.4%			9,662,062	3.8%
7	Lighting	0	0.0%				
8	**Total**	$ 159,147,527	100.0%	$ 1,353,892,942	100.0%	$ 253,614,018	100.0%

Purchase of Receivables
For FPFTY 2027

Schedule-13

Line		Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Sales (MWh)	36,412,039	11,346,277	2,804,983	7,549,351	288,122	13,820,127	467,014	136,165
2	% R and RH		80.2%	19.8%					
3	% PD and HT					2.0%	98.0%		
4	Total Amount ($)	$1,428,686,190	329,053,287	81,347,297	523,861,507	10,015,951	480,428,081	-	3,980,068
	POR Allocator	**100%**	**23.03%**	**5.69%**	**36.67%**	**0.70%**	**33.63%**	**0.00%**	**0.28%**

Demand Allocator

Schedule-14

October 2024 to September 2025

Line	Demand Allocator	Total MWs	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	1CP	8,379,496	4,007,744	584,624	1,606,611	55,471	2,044,013	75,331	5,701
2	NCP- Primary HT	9,667,374	4,030,305	1,232,991	1,796,705	62,135	2,363,175	137,941	44,122
3	NCP- Primary	7,166,258	4,030,305	1,232,991	1,796,705	62,135	-	-	44,122
4	NCP- Secondary	7,104,123	4,030,305	1,232,991	1,796,705	-	-	-	44,122
5									

Schedule-15

Energy Allocator
For FPFTY 2027

Line	Rate Class	Function	MWh Deliveries at Meter	MWh Deliveries at Generation
1	Residential	Secondary	11,346,277	12,516,078
2	Residential Heating	Secondary	2,804,983	3,094,177
3	General Service	Secondary	7,549,351	8,327,689
4	Primary Distribution	Primary	288,122	312,353
5	High Tension	HT	13,820,127	14,368,786
6	Electric Propulsion	HT	467,014	485,555
7	Lighting	Secondary	136,165	150,203
8	**Total**		36,412,039	39,254,841

PECO Exhibit JD-8:
Development of Unbundled Cash Working Capital Rate for the Generation Supply Adjustment

PECO Energy Company
Estimated Cash Working Capital Rate for the GSA
To be Effective January 1, 2027
('000s)

1	CWC Rate Base Allocated to Purchased Power[(1)]	$	91,220
2	Rate of Return[(2)]		8.08%
3	Return on CWC Rate Base	$	7,371
4	Income Taxes on Equity portion of Return[(3)]	$	1,926
5	Gross Receipts Tax @ 5.9%	$	583
6	Total Revenue Requirement	$	9,880
7	Default Service Sales (MWH)		14,416,324
8	Estimated Rate per kWh	$	0.00069

Notes:
1 PECO Exhibit JD-1, Page 1, Line 30
2 PECO Exhibit MJT-1, Schedule A-1
3 PECO Exhibit JD-1, Page 2, Line 70

PECO Exhibit JD-9:
Development of Unbundled Cash Working Capital Rate for the Transmission Service Charge

PECO Energy Company
Estimated Cash Working Capital Rate for the TSC
To be Effective January 1, 2027
('000s)

1	CWC Rate Base Allocated to Transmission TSC [1]	$	12,703
2	Rate of Return[2]		8.08%
3	Return on CWC Rate Base	$	1,026
4	Income Taxes on Equity portion of Return[3]	$	268
5	Gross Receipts Tax @ 5.9%	$	81
6	Total Revenue Requirement	$	1,376
7	Default Service Peak Forecast (MW)		4,428
8	Estimated Rate per MW-year	$	311

Notes:
1 PECO Exhibit JD-1, Page 1, Line 38
2 PECO Exhibit MJT-1, Schedule A-1
3 PECO Exhibit JD-1, Page 2, Line 81

PECO Statement No. 9:
Direct Testimony of Joseph A. Bisti

PECO ENERGY COMPANY
STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECT: REVENUE ALLOCATION; RATE DESIGN; RECOVERY OF CUSTOMER ASSISTANCE PROGRAM COSTS; AND DEVELOPMENT OF PROPOSED NEW RATES

DATED: MARCH 30, 2026

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DIRECT TESTIMONY

OF

JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Joseph A. Bisti. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a Manager of Rate Analysts. I am responsible for retail tariff administration, project management, and regulatory affairs relating to PECO's gas and electric operations.

3. Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Economics from The College of New Jersey in 2000, a Master of Science in Training and Organizational Development from Saint Joseph's University in 2009, and a Graduate Certificate in Utility Management from Willamette University in 2012. In 2015, I earned a certification as a Project Management Institute Professional in Business Analysis. In September of 2022, I was promoted to my current position. My professional experience includes various roles involving business analysis, project leadership, and regulatory compliance within PECO's Retail Rates, Energy Acquisition, and Information Technology departments.

4. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) describe how PECO proposes to allocate its claimed revenue increase among rate classes and explain the principles that guided PECO in developing its proposed revenue allocation; (2) describe the changes PECO is proposing in the rate design for certain rate classes, why PECO is proposing these changes, and how the proposed new rates were developed; and (3) explain PECO's proposal for the recovery of Customer Assistance Program ("CAP") costs.

5. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

Exhibit JAB-1	Proposed Revenue Allocation, Proposed Increases by Class and Class Rates of Return and Relative Rates of Return under Proposed Rates
Exhibit JAB-2	Relevant Electric Service Tariff Pages (Blacklined to Show Changes)
Exhibit JAB-3	Proof of Revenues at Present and Proposed Rates
Exhibit JAB-4	Modified Base Rate Recovery of CAP Revenues in Universal Service Fund Charge
Exhibit JAB-5	Calculation of CAP Cash Working Capital Offset Factor

II. REVENUE ALLOCATION

6. Q. Please state the principles that guided PECO in developing its proposed revenue allocation.

A. The proposed revenue allocation reflects a reasonable balance of accepted principles for designing utility rates. Specifically, PECO considered the following principles in developing its proposed revenue allocation:

1. The results of the class cost-of-service study ("COSS") prepared by Company witness Jiang Ding and discussed in PECO Statement No. 8 should be used as a guide in allocating the proposed revenue increase among rate classes;
2. The overall proposed revenue allocation should produce reasonable movement toward the cost of service indicated by the COSS; and
3. Customer impacts should be considered, and PECO should attempt to avoid increases in revenue for major rate classes that, on a percentage basis, exceed two times the proposed system average increase.

7. Q. Has an exhibit been prepared showing the cost of service by rate class?

A. Yes. A summary of class cost-of-service data is provided in PECO Exhibit JD-1, sponsored by and discussed in the direct testimony of PECO witness Jiang Ding (Statement No. 8). PECO Exhibit JD-1 shows, at page 1, line 22, the overall and class rates of return produced by the Company's current electric distribution base rates based on its supporting data for the 12 months ending December 31, 2027, which is the fully projected future test year ("FPFTY") in this case. PECO Exhibit JD-1 also shows, at page 3, line 105, the increase or

decrease in dollars that each rate class would have to receive for its revenues to equal its indicated class cost of service. As indicated by the guiding principles I summarized above, while the results of the Company's COSS are an important guide in evaluating its proposed revenue allocation, they are not the only factor that must be considered.

8. Q. Please discuss the principle of gradualism and how it influenced PECO's proposed revenue allocation.

A. The ratemaking principle of gradualism, as traditionally applied in Pennsylvania, guides utilities to avoid abruptly increasing rates in favor of slower adjustments that incrementally move rates toward the actual cost of service over time. PECO's proposed revenue allocation in this case attempts to balance gradualism and other ratemaking principles, more closely aligning the class rates of return with the proposed system average rate of return while striving to limit the degree to which rates for other classes diverge from their indicated cost of service. Under PECO's proposed revenue allocation and rate structure, the maximum increase for any rate class is 2.0 times the system average increase to prevent rate shock.

9. Q. What is the revenue allocation that PECO determined to be appropriate in this case?

A. PECO's proposed revenue allocation is presented in PECO Exhibit JAB-1.

10. Q. Why is the proposed revenue allocation reasonable?

A. The proposed revenue allocation in PECO Exhibit JAB-1 is reasonable because it appropriately reflects the principles I discussed previously. Using the COSS

discussed by Ms. Ding as a guide, the Company developed the proposed rates to make meaningful movement toward each class's cost of service where necessary, as evidenced by the relative rates of return. The class rates of return and relative rates of return[1] at present and proposed rates in PECO Exhibit JAB-1 are provided in Table 1 below.

Table 1, Relative Rates of Return Under Company's Proposal

Rate Class	Under Present Rates	Under Proposed Rates
R	1.03	1.01
RH	0.63	0.83
GS	1.11	1.05
PD	1.20	1.11
HT	1.08	1.05
EP	0.56	0.82
Lighting	1.37	1.00

11. Q. Please explain the significance of the relative rates of return shown in PECO Exhibit JAB-1 to which you previously referred.

A. The relative rate of return is the ratio of the rate of return for a rate class to the system average rate of return. Relative rates of return are commonly used to test whether a proposed revenue allocation moves each rate class closer to, or at least no further from, the system average rate of return. A relative rate of return of 1.00 would mean the class rate of return equals the system average rate of return and, therefore, class revenues equal the class cost of service.

[1] A relative rate of return is the ratio of the rate of return for a rate class to the system average rate of return.

Conversely, relative rates of return that depart from 1.00 indicate that the class rates of return are higher or lower than the system average rate of return and, therefore, the classes are providing revenues higher or lower than their indicated cost of service.

III. RATE DESIGN

12. Q. Explain in general how PECO proposes to change the charges within each rate schedule to recover the revenue allocated to each rate class.

A. PECO proposes to increase or decrease each of the charges within each rate schedule in proportion to the proposed revenue change allocated to that rate class. PECO Exhibit JAB-2 is a copy of the Company's Tariff Electric-Pa. P.U.C. No. 9 ("Tariff No. 9") that shows, by strike-out and blacklining, the proposed rate changes I discuss below, as well as the proposed changes in rules, regulations, rate schedules, and riders discussed by Megan A. McDevitt in PECO Statement No. 10. Tariff No. 9 is being filed with the Secretary of the Pennsylvania Public Utility Commission ("PUC" or the "Commission") as part of PECO's base rate filing.

Currently, service is provided under the Company's Tariff Electric-Pa. P.U.C. No. 8 ("Tariff No. 8") and associated supplements. It is anticipated that Tariff No. 9, which was filed as part of this case on 60 days' notice, will be suspended by operation of Section 1308(d) of the Public Utility Code pending an investigation by the Commission. Because it is possible and, in fact, likely, that changes will be made, via subsequently filed supplements, to Tariff No. 8 during the period Tariff No. 9 is suspended, any provisions of the current tariff

that will continue beyond the end of the suspension period and have not already been incorporated in Tariff No. 9 will be merged into the tariff that will be filed as part of PECO's compliance filing at the conclusion of this proceeding.

13. Q. Why is PECO proposing to increase customer charges for several rate classes by a greater percentage than the proposed overall revenue increase for those classes?

A. PECO is proposing to increase the customer charges in this manner to reduce the disparity between its current customer charge and the customer-related costs that should properly be recovered by that charge as reflected by Ms. Ding in PECO Exhibit JD-4. The change is intended to align this charge more closely with the Company's customer-classified costs.

A summary of the proposed customer charge increases is shown in Table 2 below. These changes are intended to align customer charges more closely with the Company's customer-classified costs. In most cases, the proposed modified customer charges will be closer to, but still less than, the customer charges warranted by the customer-related costs identified by Ms. Ding in PECO Exhibit JD-4.

Table 2, Proposed Base Rate Customer Charge Increases

Rate Class	Present Customer Charge	Customer-Related COSS $/Month/Customer (PECO Exhibit JD-4)	Proposed Customer Charge	Proposed % Increase
R and RH	$11.25	$38.36 (R) $38.60 (RH)	$15.00	33.3%
GS – Single Phase – No Demand	$24.47	$44.19	$27.28	11.5%

GS – Single Phase – With Demand	$31.20		$34.78	
GS - Polyphase	$74.66		$83.23	

PECO's Service Location charges for certain Lighting class rates are also intended to recover a portion of the Company's customer-classified costs. Since the results of PECO's COSS indicate an increase in customer-related costs for Lighting (PECO Exhibit JD-4 at page 3, line 14), PECO also proposes to increase Service Location charges for the applicable Lighting class rates as shown in Table 3 below.

Table 3, Proposed Service Location Charge Increases for Lighting Rate Classes

Lighting Rate Class	Present Location Charge	Proposed Location Charge	Proposed % Increase
SL-E – Street Lighting Customer-Owned Facilities	$7.65	$8.34	9.0%
SL-C – Street Lighting Control Customer-Owned Facilities	$6.48	$7.06	
TLCL – Traffic Lighting Constant Load Service	$4.22	$4.60	
AL – Alley Lighting in City of Philadelphia	$2.68	$2.92	

14. Q. Why is it important to increase customer charges and service location charges so those charges are closer to customer-classified costs?

A. Customer-classified costs are, by definition, costs that vary based on the number of customers, not usage. Such costs include, principally, but not exclusively, the cost of meters, customer service lines, and billing and meter reading.

Consequently, customer-classified costs are, on average, the same amount for each customer within a rate class. Accordingly, customer-classified costs are appropriately recovered in the customer charge, which is the same for each customer served under a given rate schedule. A utility should, to the extent practicable, avoid including customer-classified costs in variable distribution charges because to do so would make the recovery of customer-related costs a function of customers' usage, which they are not.

Misplacing customer costs in variable distribution charges has adverse consequences. First, it can create inappropriate intra-class subsidies because some customers will pay more than their share of customer-classified costs and others less, based on their relative levels of usage each month. Second, because customer costs, which are a fixed amount per customer, would be recovered in a charge that applies to usage, which varies, the Company could recover either too little or too much of its customer-related costs because of variations in customer usage.

In summary, putting customer costs in the wrong element of a rate can be unfair to both customers and the utility. For these reasons, among others, customer-related costs in a utility's cost of service should be charged to customers in a manner that appropriately reflects the nature of the costs incurred, subject to consideration of the principle of gradualism.

15. Q. What residential customer charge is PECO proposing?

A. PECO is proposing a residential base customer charge of $15.00 per month (excluding consumer education surcharges). This customer charge will be

closer to, but still less than, the customer charge warranted by the customer-related costs identified by Ms. Ding in PECO Exhibit JD-4. The revenue to be recovered from this customer charge was deducted from the total revenue target for the residential class to determine the revenue to be recovered in the variable distribution service charge. The variable distribution service charge was changed to recover the balance of the residential class revenue not recovered by the customer charge.

16. Q. Is PECO proposing changes to customer charges for other rate classes?

A. Yes. PECO is also proposing increases to customer charges as shown in Table 2 above and in PECO Exhibit JAB-3. As discussed above, customer charges are designed to recover the customer-related fixed costs of providing service and therefore should be established to align with actual customer-related costs of providing those services as evidenced by Ms. Ding in PECO Exhibit JD-4.

IV. CUSTOMER ASSISTANCE PROGRAM COST RECOVERY

17. Q. Please describe PECO's current Customer Assistance Program ("CAP") for electric customers.

A. As explained by Company witness Jacqueline F. Golden in PECO Statement No. 12, in accordance with the universal service obligations set forth in the Public Utility Code, PECO's CAP assists low-income customers in its service territory through discounted energy bills. The structure of PECO's CAP discount has evolved over time. Most recently, in December 2022, PECO implemented a new CAP Percentage of Income Payment Plan ("PIPP"), approved by the Commission in Docket No. M-2018-3005795, to provide a

percentage of income-based benefit to CAP customers.[2] The PIPP design provides eligible customers with a fixed maximum monthly bill equal to what the CAP customer can afford to pay for utility service. The fixed bill amount is determined by applying an energy burden percentage[3] to the customer's annual income. CAP bill credits are applied to reduce the customer's monthly undiscounted bill to the monthly PIPP bill amount. For billing purposes, PECO applies the lesser of the CAP PIPP bill or actual charges. Bills issued under the CAP PIPP are subject to monthly minimum bill amounts and annual maximum credit amounts based on income level and electric rate. Prior to employing a PIPP design, the Company utilized a Fixed Credit Option ("FCO") design (from October 2016 to December 2022) and a tiered-rate discount CAP structure (prior to October 2016).

In addition, customers enrolling in CAP for the first time who have unpaid arrearages that pre-date their enrollment in the program are entitled to pre-program arrearage ("PPA") forgiveness. If a customer is eligible for PPA forgiveness, the customer's total arrearage is set aside and divided into 12 equal parts. Each month the CAP customer pays their new, affordable CAP bill in full and on-time, one-twelfth of their PPA is forgiven.

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[2] *PECO Energy Co. Universal Serv. and Energy Conservation Plan for 2019-2024 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4.*, Docket No. M-2018-3005795 (Opinion and Order entered June 16, 2022) ("USECP Order").

[3] The energy burden percentage is the target percentage of household income that may be utilized to pay for utility service. Energy burden percentages vary based on the commodity (electric, electric heat, and gas) and household income level/number of residents.

18. Q. What was the dollar amount of the aggregate PIPP bill credits provided to CAP customers in 2025 and how were those costs recovered?

A. The value of the CAP bill credits provided to low-income customers through PECO's electric CAP was approximately $189.5 million in 2025. These costs are recovered through a combination of base rates and a surcharge mechanism under Section 1307 of the Public Utility Code.

In the settlement of PECO's 2010 electric base rate case ("2010 Settlement") the parties agreed that PECO would be entitled to recover $80.7 million through base rates for the costs of providing CAP bill credits to low-income customers.[4] Since that time, PECO has implemented several CAP enhancements to provide more affordable monthly bills to low-income customers based on the Commission's energy burden levels set forth in its CAP Policy Statement,[5] which have caused substantial increases in PECO's CAP program costs. As such in PECO's last base rate case at Docket No. R-2024-3046931, PECO increased the amount of PIPP bill credits included in its base rates.

19. Q. Please provide an overview of PECO's existing Universal Service Fund Charge ("USFC").

A. The USFC is PECO's Commission-approved rate mechanism for recovery of the costs of PECO's universal service programs that are not included in base

[4] *See Pa. P.U.C. v. PECO Energy Co. – Elec. Div.*, Docket No. R-2010-2161575 (Order entered Dec. 21, 2010), p. 10. In subsequent base rate cases in 2015, 2018 and 2021, PECO increased the negotiated amount established in the 2010 settlement by the overall percentage revenue increase approved by the Commission.

[5] 52 Pa. Code § 69.265.

rates. The USFC is an automatically adjusted surcharge created pursuant to Section 1307(a) of the Pennsylvania Public Utility Code.

USFC costs are reconciled on an annual basis using actual costs for a historic 12-month period ("E-Factor") and projected costs for the future 12-month period ("C-Factor"). Interest accrues from the month in which over/under collection of USFC costs occurs to the midpoint of the collection period, the sum of which results in a credit or charge to customers if costs are over- or under-collected, respectively. The cumulative amount (either positive or negative) at the end of the reconciliation period determines the E-Factor to be included in calculation of the next USFC for the subsequent period. PECO normally files its USFC reconciliation and annual rate adjustment in October of each year, with the new USFC rate becoming effective on the following January 1.

20. Q. Please describe the CAP "shortfall."

A. The CAP "shortfall" refers to the amount of aggregate bill credits (in dollars) provided to CAP customers each year that is not reflected in base rates. This shortfall is either recovered from or refunded to PECO's residential customers on an ongoing basis through PECO's USFC, with annual reconciliation of any over/under collections. Pursuant to the Commission-approved settlement of PECO's first default service proceeding (the "DSP Settlement"), the USFC is adjusted so that 73% of the total CAP shortfall amount is included in USFC

rates for residential customers.[6] The remaining 27% of the CAP shortfall is absorbed by PECO to account for the estimated impact to PECO's uncollectible expense (22%) and cash working capital requirements (5%). At that time, the 27% factor was associated with CAP program enhancements agreed to in the DSP Settlement, which would be implemented at the same time as base rates established in PECO's 2010 electric rate case. The Company has maintained these factors since its current base rates became effective on January 1, 2025 pursuant to Paragraph 18 of the 2024 Rate Case Settlement.

21. Q. Is PECO proposing to increase the amount of electric CAP bill credits included in its base rates in this proceeding?

A. Yes. The Commission's CAP Policy Statement was amended effective March 21, 2020, which, among other things, established lower recommended maximum energy burden targets for electric and gas CAP bills.[7] In accordance with the USECP Order, PECO's energy burdens were updated in late July 2022. As previously noted, in December 2022, PECO implemented its PIPP to provide eligible customers with a maximum monthly bill amount that is determined by applying an energy burden percentage to the customer's annual income. These two changes greatly increased the value and total amount of the bill credits provided to CAP customers.

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6 *See Petition of PECO Energy Co. for Approval of Its Default Serv. Program and Rate Mitigation Plan*, Docket No. P-2008-2062739 (Order entered June 2, 2009).

7 *See Universal Service Rulemaking*, Docket No. M-2019-3012599 (Final Policy Statement Order and Annex entered on Nov. 5, 2019); 50 Pa.B. 1652 (Mar. 21, 2020).

In the FPFTY, the total estimated amount of PIPP bill credits for customers projected to be enrolled in CAP as of December 31, 2027 will be approximately $250.8 million. PECO proposes to update the current base rate recovery factor within its USFC to reflect this amount, as illustrated in PECO Exhibit JAB-4. Annual reconciliation of any over/under collections will continue to be via the USFC.

22. Q. Please describe how PECO currently recovers PPA forgiveness from customers and the change the Company is proposing in this case.

A. The costs of forgiven arrearages of CAP participants are recovered through base rates. In this case, the Company proposes to recover projected PPA forgiveness costs, which are part of the overall cost of PECO's CAP, through its base rates and to reconcile PPA forgiveness costs above or below this amount through its USFC, consistent with the ratemaking treatment used by other Pennsylvania distribution companies for these CAP costs. The Company's proposed base rates reflect total PPA costs during the FPFTY of approximately $17.8 million. PECO will reconcile any over/under collections through the USFC in the same manner as PIPP bill credits using a new, separate base rate recovery factor specifically related to PPA forgiveness costs, as illustrated in PECO Exhibit JAB-4.

23. Q. Mr. Bisti, is PECO proposing to change how reconcilable CAP program costs are recovered through the USFC?

A. Yes. When additional low-income customers enroll in PECO's CAP, PECO is more likely to recover at least a portion of the costs attributable to those

customers because those costs will be collected from all residential customers through the USFC. As discussed earlier in my testimony, PECO currently applies a 22% offset factor to reconcilable CAP costs in the USFC formula to reflect uncollectible expense savings or increases associated with CAP PIPP bill discounts above or below the level embedded in base rates. PECO also applies a 5% USFC offset factor for cash working capital.

However, the value of the total PIPP bill discounts (applied to both supply and delivery charges) and PPA forgiveness costs provided by PECO each year are impacted by many variables, including the economy, commodity prices, weather and demographics. For example, if supply prices increase while all else remains constant, including the number of customers enrolled in CAP, then non-CAP customers must pay more to support the growing discounts and PPA forgiveness costs while PECO's base rate recovery remains the same. This results in higher uncollectible expenses and cash working capital requirements for PECO that have no direct correlation to the number of CAP customers.

As such, PECO proposes to establish two baselines, one for PIPP bill discounts and the other for PPA forgiveness, as triggers for applying the offset percentage within its calculation of reconcilable CAP costs to be recovered through the USFC. This change ensures that the offset percentages only reflect the impacts on PECO uncollectible expense and cash working capital requirements that result from changes in the CAP participation and PPA forgiveness levels used to set base rates.

The first of these is PECO's proposed baseline CAP participation level, specifically the Company's current projection of 145,721 electric CAP customers as of the end of the FPFTY. On a monthly basis, PECO will compare the actual month-end CAP participation level to this baseline to determine the change above or below it for that month. PECO will also calculate the actual average CAP PIPP bill credit per customer for that month, dividing the actual amount of bill credits issued in that month by the actual month-end CAP participation level. Then PECO will multiply that month's change in CAP participation by that month's average actual PIPP bill credit per CAP customer, yielding the portion of the basis for offset related to the variance in CAP PIPP bill credits.

The second is PECO's proposed baseline PPA forgiveness, specifically the Company's current projection of $17,845,130 for electric CAP customers during the FPFTY. On a monthly basis, PECO will compare the actual PPA forgiveness costs to one-twelfth of this baseline to determine the PPA costs above or below the baseline for that month, yielding the portion of the basis for offset related to PPA forgiveness.

PECO will then sum both of the above results and apply the offset factor percentage to the total, yielding the offset amount to be reflected in the USFC reconciliation on PECO's uncollectible expense and cash working capital requirements for that month.

24. Q. Is PECO proposing any other changes to the USFC related to CAP program costs?

A. Yes. PECO proposes to update the predetermined offset factor percentage applied to reconcilable CAP costs recovered through the USFC from 27% to 11.9% based on the most recent data on uncollectible expense and cash working capital, as discussed below.

With respect to the uncollectible expense component established in 2008 by the DSP Settlement, PECO has evaluated its recent bad debt write-off trends for CAP and non-CAP residential customers. Based on that analysis, PECO is proposing to lower the uncollectible offset percentage from 22% to 8.2%. PECO calculated its claim for uncollectible accounts expense using a three-year historic average ratio of net charge-offs as a percentage of billed revenues. As shown in the table below, the uncollectible accounts rate for CAP customers was calculated in the same manner by using the Company's actual charge-off experience for 2023, 2024 and 2025 divided by PECO's total billed revenues for the same three years. The proposed offset percentage of 8.2% represents the difference between the uncollectible accounts rate for CAP customers (9.33%) and all residential non-CAP customers (1.15%).

Table 4, CAP vs. Non-CAP Uncollectible Accounts Charge-Off Rate

	CAP Customer Billing vs. Net Charge-Offs				Non-CAP Residential Customer Billings vs. Net Charge-Offs			
	2023	**2024**	**2025**	**3-Yr Avg**	**2023**	**2024**	**2025**	**3-Yr Avg**
Annual Billing ($M)	$ 94.3	$ 97.6	$ 114.2	$ 102.0	$ 2,907.2	$ 2,937,6	$ 3,379,7	$ 3,074.8
Net Charge-Offs ($M)	$ 7.9	$ 7.9	$ 12.7	$ 9.5	$ 34.0	$ 20.1	$ 52.1	$ 35.4
Ratio (%)	8.4%	8.1%	11.2%	9.33%	1.2%	0.7%	1.5%	1.15%

PECO is also proposing to lower the cash working capital offset percentage from 5% to 3.7% as discussed later in my testimony.

25. Q. What was the basis for the calculation underlying the current 5% cash working capital adjustment established in the settlement of PECO's 2008 default service proceeding?

A. The basis for the negotiated amount in the 2008 DSP Settlement was the methodology originally recommended by the Office of Consumer Advocate ("OCA") in PECO's 2008 gas rate case using the age of residential arrears at charge-off based on data at that time (the "2008 OCA Methodology").

26. Q. At what point in time does PECO write off arrearages as uncollectible?

A. The due date for payment of a monthly PECO bill is approximately 22 days from the billing date, depending upon the timing of weekends and holidays. Write-offs are the last action on final-billed overdue residential accounts. The arrearage is written off approximately 70 days after a final bill is issued and the account is no longer active, again depending upon weekend and holiday timing.

27. Q. How did PECO calculate the updated 3.7% cash working capital offset using the 2008 OCA Methodology?

A. The Company used a two-step process. First, the Company determined the average age of a typical low-income customer arrearage prior to write-off by calculating the average arrears of CAP customers earning pre-program arrearage forgiveness in 2025 – approximately $833 – by dividing $20,223,667 in forgiven arrearages by the 24,278 new CAP enrollments for 2025. The average $833 arrearage represents about four months of a typical CAP customer non-discounted monthly bill ($202). Thus, the average lag is 146 days. In the second step of this calculation, the Company applies a daily cost of capital to the 146-day lag associated with CAP pre-program arrearages to arrive at 3.7%. Those calculations are set forth in PECO Exhibit JAB-5.

V. REVENUE EFFECT BY RATE SCHEDULE, PROOF OF REVENUES, AND SCALE-BACK

28. Q. Have you prepared a summary of distribution revenues at present and proposed rates for each rate class?

A. Yes. PECO Exhibit JAB-1 shows revenue at both present rates and proposed rates, as well as the percentage increases each class will receive on an overall basis.

29. Q. Have you prepared proofs of revenue with respect to PECO's present and proposed rates?

A. Yes. PECO Exhibit JAB-3 is a proof of revenue with respect to PECO's present and proposed rates, based on pro forma billing determinants for the FPFTY.

This exhibit is tied to the portion of PECO Exhibit JAB-1 that addresses the increased revenue that would be required.

30. Q. Please explain the adjustment made to the proof of revenues at present rates for the Company's Distribution System Improvement Charge ("DSIC").

A. The DSIC is a rate adjustment mechanism that permits PECO to recover the fixed costs of DSIC-eligible property between base rate cases through a separate, reconcilable charge established pursuant to Section 1353 of the Public Utility Code. The Commission approved PECO's establishment of a DSIC by its final order entered October 22, 2015, at Docket No. P-2015-2471423. PECO began to charge a DSIC effective with bills rendered on or after April 1, 2018.

As required by the terms of the DSIC and Section 1358(b) of the Public Utility Code, PECO is currently charging a DSIC of 0.0%, having reset the DSIC to zero as of January 1, 2025 – the effective date of new base rates established by the Commission's Final Order in PECO's 2024 rate case at Docket R-2024-3046931. PECO has filed a DSIC charge of 0.11% effective with bills rendered on or after April 1, 2026 and intends to reset its DSIC charge at zero on the effective date of new rates established through this proceeding. PECO may file a DSIC charge to be effective January 1, 2027 or later for the sole purpose of reconciling residual over and under-collections experienced before the end of 2026. The fixed costs of DSIC-eligible property that PECO will continue to recover through the effective date of its new base rates have been included in the Company's claimed rate base and reflected in the revenue

requirement used to establish its proposed rates. Consequently, to properly compare PECO's revenues at present rates to revenues at its proposed base rates, PECO's proof of revenue at present rates has been adjusted by customer class to include the revenues billed under its DSIC.

31. Q. How does PECO propose to scale-back the proposed rates if it is granted less than the revenue increase it requested?

A. In the event PECO is granted less than its requested increase, PECO proposes that:

(1) the revenue increases proposed for all rate classes will be reduced in proportion to the proposed increase for each class; and

(2) the customer charges for all rate classes remain as proposed, and all other rates and charges for all rate schedules be reduced proportionately to produce the revenue target for each rate class.

VI. CONCLUSION

32. Q. Please summarize your conclusions.

A. PECO's proposed rates reflect a reasonable allocation of the Company's proposed revenue increase and a reasonable rate design for each rate schedule. The proposed rate design changes are consistent with the results of the COSS identified by Ms. Ding and applicable principles of rate structure and rate design, including gradualism.

33. Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Joseph A. Bisti, hereby state that I am a Manager of Rate Analysts for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 9 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Joseph A Bisti

Dated: March 30, 2026

Joseph A. Bisti

PECO Exhibit JAB-1:
Proposed Revenue Allocation and Rates of Return by Rate Class

PECO Energy Company (Electric)
Proposed Revenue Allocation and Rates of Return by Rate Class

Rate Class	(1) Current Distribution Revenue	(2) Proposed Distribution plus GSA / TSC Working Capital Adjustment	(3) *(2) - (1)* Total Revenue Ask	(4) 2026 GSA / TSC Working Capital Adjustment	(5) *(3) - (4)* Distribution Revenue Ask	(6) *(1) + (5)* Proposed Distribution Revenue	(7) *(5) / (1)* % Increase	(8) Increase vs. System Avg
Residential (R)	$ 1,134,536,373	$ 1,359,399,683	$ 224,863,310	$ 3,627,157	$ 221,236,153	$ 1,355,772,526	19.8%	0.93
Residential Heating (RH)	$ 219,356,871	$ 289,727,110	$ 70,370,239	$ 837,670	$ 69,532,569	$ 288,889,440	32.1%	1.50
General Service (GS)	$ 344,238,417	$ 416,928,034	$ 72,689,617	$ 828,554	$ 71,861,063	$ 416,099,480	21.1%	0.99
Primary Distribution (PD)	$ 9,858,655	$ 11,720,567	$ 1,861,912	$ 11,803	$ 1,850,109	$ 11,708,764	18.9%	0.88
High Tension (HT)	$ 234,093,299	$ 287,852,673	$ 53,759,374	$ 487,027	$ 53,272,347	$ 287,365,646	23.0%	1.07
Electric Propulsion (EP)	$ 9,662,749	$ 13,771,599	$ 4,108,850	$ 7,178	$ 4,101,672	$ 13,764,421	42.5%	1.99
Lighting	$ 28,837,910	$ 30,290,678	$ 1,452,768	$ 3,039	$ 1,449,729	$ 30,287,639	5.0%	0.24
Total	$ 1,980,584,273	$ 2,409,690,343	$ 429,106,070	$ 5,802,427	$ 423,303,643	$ 2,403,887,916	21.4%	

Rate Class	(9) Present Rate of Return	(10) *(9) / Average of (9)* Present Relative Rate of Return	(11) Proposed Rate of Return	(12) *(11) / Average of (11)* Proposed Relative Rate of Return
Residential (R)	5.57%	1.03	8.20%	1.01
Residential Heating (RH)	3.42%	0.63	6.68%	0.83
General Service (GS)	6.02%	1.11	8.50%	1.05
Primary Distribution (PD)	6.52%	1.20	8.97%	1.11
High Tension (HT)	5.87%	1.08	8.50%	1.05
Electric Propulsion (EP)	3.05%	0.56	6.63%	0.82
Lighting	7.44%	1.37	8.12%	1.00
Total	5.41%		8.08%	

PECO Exhibit JAB-2:
Relevant Electric Service Tariff Pages
(Blackline)

Exhibit JAB-2

ELECTRIC PA P.U.C NO. 9

SUPERCEDES ELECTRIC PA P.U.C. NO. 8 AND ALL SUPPLEMENTS THERETO

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PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 30, 2026 **Effective May 29, 2026**

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ISSUED BY: David M. Vahos – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATION - Original Page No. 8 - Revisions to the definitions of "Standard High Tension" and "Suitable Location".

RULES AND REGULATIONS – Original Page No. 12 – Edit to definition on 3.7 NONSTANDARD SERVICE.

RULES AND REGULATIONS – Original Page No. 17 – Update to Rule 7.2.E - expand the list of acceptable securities and clarify up-front payment amount.

RULES AND REGULATIONS – Original Page No. 18 – **7.3 UNDERGROUND SERVICE IN NEW RESIDENTIAL DEVELOPMENTS.** Modify Rule 7.3 to allow PECO to obtain security. **7.4 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES.** Specify the application of Rule 7.4.

RULES AND REGULATIONS – Original Page No. 30 – 18.7 RECONNECTION CHARGE - Modify Rule 18.7 to waive certain reconnection fees for eligible low-income customers.

INCREMENTAL COVID-19-RELATED UNCOLLECTIBLE EXPENSE (ICUS) - page deleted.

FIBER AFFILIATE REVENUE SURCHARGE (FARS) - page deleted.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 - Original Page No. 35 – Working Capital (WC) rate updated.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 – Original Page No. 38 – Working Capital (WC) rate updated.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) - Original Page No. 42 – Changes made to E Factor and L Factor. Offset factor updated. Methodology added within definition of "Reconcilable CAP Costs" for application of offset factor to reflect only the impacts from changes in CAP participation and PPA forgiveness baselines.

PROVISIONS FOR RECOVERY OF CONSUMER EDUCATION COSTS – Original Page No. 43 – Added new H factor.

TRANSMISSION SERVICE CHARGE – Original Page No. 44 - Working Capital (WC) rate updated.

VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER (VSRII RIDER) – Original Page No. 50. New Rider added.

ENERGY EFFICIENCY AND CONSERVATION (EE&C) REGULATORY ASSET RIDER – Original Page No. 51 – New Rider added.

RATE R RESIDENCE SERVICE – Original Page No. 52 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE R H RESIDENTIAL HEATING SERVICE – Original Page No. 53 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE GS GENERAL SERVICE- Original Page No. 57 – Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability. Update to DETERMINATION OF BILLING DEMAND.

RATE PD PRIMARY-DISTRIBUTION POWER - Original Page No. 59 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE HT HIGH -TENSION POWER - Original Page No. 60 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE EP – Original Page No. 61 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE POL PRIVATE OUTDOOR LIGHTING – Original Page No. 62 – Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES – Original Page No. 64 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE SL-E STREET LIGHTING CUSOMTER OWNED FACILITIES Original Page No. 66 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITES - Original Page No. 68 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE – Original Page No. 71 – Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

RATE AL – Original Page No. 73 - Distribution prices updated. Removed ICUS and FARS applicability. Added VSRII and EE&C Reg Asset applicability.

APPLICABILITY INDEX OF RIDERS - Original Page No. 74 – page numbers updated.

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) – Deleted pages for rider rules that were prior to January 1, 2026.

NIGHT SERVICE GS RIDER - Original Page No. 89 - Distribution prices updated.

NIGHT SERVICE HT RIDER - Original Page No. 90 - Distribution prices updated.

NIGHT SERVICE PD RIDER - Original Page No. 91 - Distribution prices updated.

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LIST OF COMMUNITIES SERVED

PHILADELPHIA:
CITY AND COUNTY OF Philadelphia.

DELAWARE COUNTY:
CITY: Chester.

BOROUGHS: Aldan, Brookhaven, Chester Heights, Clifton Heights, Collingdale, Colwyn, Darby, East Lansdowne, Eddystone, Folcroft, Glenolden, Lansdowne, Marcus Hook, Media, Millbourne, Morton, Norwood, Parkside, Prospect Park, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Haverford, Lower Chichester, Marple, Nether Providence, Radnor, Ridley, Springfield, Tinicum, Upper Chichester, Upper Darby.

SECOND-CLASS TOWNSHIPS: Bethel, Birmingham, Chester, Concord, Edgmont, Middletown, Newtown, Thornbury, Upper Providence.

BUCKS COUNTY:
BOROUGHS: Bristol, Chalfont, Doylestown, Dublin, Hulmeville, Ivyland, Langhorne, Langhorne Manor, Morrisville, New Britain, New Hope, Newtown, Penndel, Telford, Tullytown, Yardley.

FIRST-CLASS TOWNSHIPS: Bristol.

SECOND-CLASS TOWNSHIPS: Bedminster, Bensalem, Buckingham, Doylestown, Falls, Hilltown, Lower Makefield, Lower Southampton, Middletown, New Britain, Newtown, Northampton, Plumstead, Solebury, Upper Makefield, Upper Southampton, Warminster, Warrington, Warwick, Wrightstown.

MONTGOMERY COUNTY:
BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Jenkintown, Lansdale, Narberth, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

FIRST-CLASS TOWNSHIPS: Abington, Cheltenham, Hatfield, Lower Merion, Lower Moreland, Lower Pottsgrove, Plymouth, Springfield, Upper Dublin, Upper Gwynedd, Upper Moreland, Upper Pottsgrove, West Norriton, West Pottsgrove.

SECOND-CLASS TOWNSHIPS: East Norriton, Franconia, Horsham, Limerick, Lower Frederick, Lower Gwynedd, Lower Providence, Lower Salford, Marborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Merion, Upper Providence, Upper Salford, West Vincent, Whitemarsh, Whitpain, Worcester.

CHESTER COUNTY:
CITY: Coatesville.

BOROUGHS: Avondale, Downingtown, Kennett Square, Malvern, Modena, Oxford, Parkesburg, Phoenixville, South Coatesville, Spring City, West Chester, West Grove.

FIRST-CLASS TOWNSHIP: Caln.

SECOND-CLASS TOWNSHIPS: Birmingham, Charlestown, East Bradford, East Brandywine, East Caln, East Coventry, East Fallowfield, East Goshen, East Marlborough, East Nantmeal, East Nottingham, East Pikeland, East Vincent, East Whiteland, Easttown, Elk, Franklin, Highland, Kennett, London Britain, Londonderry, London Grove, Lower Oxford, New Garden, Newlin, New London, North Coventry, Penn, Pennsbury, Pocopson, Sadsbury, Schuylkill, South Coventry, Thornbury, Tredyffrin, Upper Oxford, Upper Uwchland, Uwchland, Valley, Wallace, Warwick, West Bradford, West Brandywine, West Caln, West Fallowfield, West Goshen, West Marlborough, West Nantmeal, West Nottingham, West Pikeland, West Sadsbury, Westtown, West Vincent, West Whiteland, Willistown.

YORK COUNTY:
BOROUGH: Delta.

SECOND CLASS TOWNSHIPS: Chanceford, Fawn, Lower Chanceford, Peach Bottom.

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HOW TO USE LOOSE-LEAF TARIFF

1. This Tariff is issued on the loose-leaf plan. Each page will be issued as "original page," consecutively numbered, commencing with the title page, which in all cases will be considered as Page No. 1. For example: "Original Page No. 2", "Original Page No. 3," etc.

2. All changes in, additions to, or eliminations from, original pages, will be made by the issue of consecutively numbered supplements to this Tariff and by reprinting the page or pages affected by such change, addition, or elimination. Such supplements will indicate the changes which they effect and will carry a statement of the make-up of the Tariff, as revised. The Table of Contents will be reissued with each supplement.

3. When a page is reprinted the first time, it will be designated under the P.U.C. number as "First Revised Page No...," the second time as "Second Revised Page No...," etc. First revised pages will supersede original pages; second revised pages will supersede first revised pages, etc.

4. When changes or additions to be made require more space than is available, one or more pages will be added to the Tariff, to which the same number will be given with letter affix. For example, if changes were to be made in Original Page No. 2 and, to show the changed matter, more than one page should be required, the new page would be issued as "First Revised Page No. 2, superseding Original Page No. 2"; and the added page would be issued as "Original Page No. 2A." If a second added page should be required, it would be Issued as "Original Page No. 2B." Subsequent reprints will be consecutively designated as "First Revised...," "Second Revised...," etc.

5. On receipt of a revised page it will be placed in the Tariff immediately following the page which it supersedes, and the page which is to be superseded thereby plainly marked "See following page for pending revision." On the date when such revised page becomes Effective the page superseded should be removed from the Tariff.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

a.c. - alternating current

Advanced Meter - Advanced Meter shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Services - Advanced Meter Services shall have the meaning set forth in the Electric Generation Supplier Coordination Tariff.

Advanced Meter Service Provider or AMSP - The Company or an EGS that provides Advanced Meter Services.

AEPS – Alternative Energy Portfolio Standard – statute that requires electric distribution companies and electric generation suppliers to acquire a certain percentage of their energy from alternative energy sources.

Available rate - A rate which may be obtained by a customer if the use of service conforms to the character of service contemplated in the rate, and the location is such that this service can be supplied from existing facilities of the Company.

Bad credit - A customer shall be deemed by the Company to have bad credit if the customer has been delinquent on payment of two consecutive bills or three or more bills in the last twelve billing cycles or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles. Industrial and commercial customers also shall be deemed by the Company to have bad credit if the customer is insolvent, (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has a class of publicly-traded debt outstanding that is rated to be below investment grade, or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles.

Base Rate (or rate) - The Base Rates are Rates R, R-H, RS-2, GS, PD, HT, POL, SL-S, SL-E, SL-C, TLCL, EP, and AL.

Billing demand - The calculated or measured demand after correction, if any, for power factor; except that the billing demand may be limited to a minimum figure.

Btu - British thermal unit.

Capacity charge - A charge based upon demand, either with or without power factor correction.

Competition Act - The Electricity Generation Customer Choice and Competition Act, 66 Pa.C.S. §2801, et seq.

Competitive Energy Supply - unbundled energy and capacity provided by an Electric Generation Supplier.

Consolidated EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Consolidated EGS Billing - Billing provided by an EGS as provided for in Electric Generation Supplier Coordination Tariff.

Continuous service – Service which the Company endeavors to keep available at all times.

Creditworthy - A creditworthy customer pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether a customer is creditworthy with respect to a particular account, the Company will evaluate the customer's record of paying Company charges for all of the customer's other Company accounts, and may also take into consideration the customer's general credit.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. For purposes of billing for an Electric Generation Supplier (as defined below), the term customer may include all meter locations for which a summary bill is provided. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules and Regulations, an EGS may act as agent for an end use customer upon written authorization to PECO Energy which may be part of the notice of EGS selection.

Customer's service extension - The facilities extending from the customer's service-receiving equipment to the Company's service supply lines.

Default Service (DS) - The provision of energy or energy and capacity by PECO Energy as Default Service Provider to customers that are: (1) not eligible to obtain Competitive Energy Supply, (2) choose not to obtain Competitive Energy Supply, (3) return to default service after having obtained Competitive Energy Supply or Competitive Default Service, or (4) who contract for Competitive Energy Supply from an EGS (as defined below) that fails to deliver such energy or energy and capacity.

Default Service Provider (DSP) – The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation.

Demand - The maximum rate-of-use of energy during a specified time interval, expressed in kilowatts.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Direct Access - Direct Access shall have the meaning set forth in the Competition Act.

Electric Distribution Company (EDC) - Electric Distribution Company (EDC) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier (EGS) - Electric Generation Supplier (EGS) shall have the meaning set forth in the Competition Act.

Electric Generation Supplier Coordination Tariff (or Supplier Tariff)- PECO Energy's Electric Generation Supplier Coordination Tariff, provides procedures for EGS & PECO EDC interaction to make arrangements necessary to implement Direct Access for retail customers.

Energy Supply Charge (Generation Charge) - PECO Energy's charge for energy or energy and capacity to customers that receive Default Service.

Energy charge - a charge based upon kilowatt-hours of use.

FERC - the Federal Energy Regulatory Commission.

Fixed Distribution Service Charge (Customer Charge) – A charge to recover costs caused by the presence of the customer on the system other than the costs associated with the customer's demand or energy consumption.

Holidays - New Year's Day, Martin Luther King, Jr.'s Birthday, Presidents' Day, Good Friday, Memorial Day, Juneteenth, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, Friday after Thanksgiving, Christmas Day and Sundays.

Hp, horsepower - As used herein, horsepower shall be computed as the equivalent of 750 watts.

Initial Contract Term - An initial contract term for a service location shall be 1) the customer's first Term of Contract for service to the location or 2) the first Term of Contract after the customer changes service for a location to a different Rate.

Interest Index – An annual interest rate determined by the average of one-year Treasury Bills for September, October and November of the previous year.

KV, kilovolts - 1000 volts.

KVA, kilovoltampere - Unit of measurement of rate-of-use, which determines electrical capacity, required; it is obtained by multiplying the voltage of a circuit by its amperage.

KW, kilowatt - Unit of measurement of useful power.

KWh, kilowatt-hour - Unit of measurement of energy; an amount equivalent to the use of one kilowatt for one hour.

Lumen - Unit of measurement of quantity of light.

Measured Demand - A customer's highest demand during a 30-minute time interval in a billing period.

Month - A month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive readings of the Company's meter or meters installed on the customer's premises.

PaPUC or Commission - The Pennsylvania Public Utility Commission.

PECO Energy or the Company - PECO Energy Company.

Point of Delivery - The single service point at which the service-supply lines of the Company terminate and the customer's facilities for receiving the service begin.

PJM - PJM shall mean the PJM Interconnection, L.L.C.

PJM System - PJM System shall mean the transmission facilities located in the Mid-Atlantic Region that are controlled by PJM.

Power Factor - As used herein, power factor is, in a single-phase circuit, the ratio of the watts to the voltamperes, and in a polyphase circuit, is the ratio of the total watts to the vector sum of the volt-amperes in the several phases.

Principal Office – The Company's Main Office Building is located at 2301 Market Street, Philadelphia, Pa. 19103.

Property Line - The division line between land held in or for private use, and land in which the public or the Company has a right of use; or, the division line between separately owned or occupied land.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Separate EDC Billing - Billing provided by the Company as provided for in the Electric Generation Supplier Coordination Tariff.

Separate EGS Billing - Billing provided by an EGS as provided for in the Electric Generation Supplier Coordination Tariff.

Service - The distribution of energy for use by the customer, including all things done by the Company in connection with such distribution. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

- standard single-phase secondary: alternating current, 60 hertz, in accordance with Tariff Rule 2.5 (Single-Phase Up To 150 kVA:

  (a) nominally 120/240 volts, 3 wires;
  (b) nominally 120 volts, 2 wires to installations consisting of not more than two 15-ampere branch circuits;
  (c) nominally 120/208 volts, 3 wires, for residential service, where available in conjunction with standard polyphase secondary 120/208 volts, 3-phase, 4 wires.

- standard polyphase secondary; alternating current, 60 hertz. Only one service is available to a building. However, the Company will provide standard service to customer premises containing multiple buildings in accordance with Tariff Rule 2.2 (Single-Point Delivery). For purposes of determining service capacity and parallel-generating capacity limits, a building is defined as a structure, separated from other structures, or a portion of a contiguous structure separated from the remainder of the structure by approved firewalls. When demand or service voltage requires the installation of transformation equipment on the owner's premises, the transformation shall consist of a pad mounted transformer installed at a location provided by the owner and approved by the Company outside the building or a transformer bank installed inside the building in a vault located on the ground floor or one story below grade, meeting National Electrical Code requirements. The Company will not install, own or maintain any conductors inside or beneath a building nor install indoor transformation in areas supplied by or designated to be supplied at 33,000 volts or greater.
  (a) nominally 120/240 volts, 2-phase, 5 wires; only available in areas supplied by 2-phase distribution facilities located along public highways or private rights-of-way and limited to service capacities of 100 kVA or less;
  (b) nominally 240 volts, 3-phase, 3 wires; a fourth wire neutral will be extended for the supply of 120/240 volt single-phase equipment in combination with the service where neither the service capacity required nor the parallel-generating capacity required exceeds 15 kVA on any one of the phases. Where the demand to a single premises exceeds 100 kVA, transformers will be installed on the premises at a suitable location provided by the owner. The service capacity and the parallel-generating capacity are both limited to 300 kVA for transformers located inside the building and 500 kVA for transformers located outside the building.
  (c) nominally 120/208 volts, 3-phase, 4 wires, (where 3-phase distribution is available) for the exclusive supply of secondary service to a building or group of contiguous buildings occupied by one or more than one customer, with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located either inside or outside the building. When either exceeds 750 kVA for transformers located inside the building the only rate option available to the customer will be Rate HT. When either exceeds 750 kVA but remains at or below 1,500 kVA for transformers located outside of the building, the customer can request service at 277/480 volts, 3-phase 4-wires from transformers located outside of the building. Otherwise, the only rate option available to the customer will be Rate HT. When a suitable transformer location is not reasonably available on the premises and the demand does not exceed 100 kVA, service may be supplied at the Company's discretion from aerial distribution facilities located along public highways.
  (d) nominally 277/480 volts, 3-phase, 4 wires (where 3-phase distribution is available) for the exclusive supply of secondary service to a building occupied by one or more than one customer with transformers and secondaries installed on the premises at suitable locations provided by the owner. The service capacity and the parallel-generating capacity are both limited to 750 kVA for transformers located inside the building and 1,500 kVA for transformers located outside the building. If either exceeds these limits the only rate option available to the customer will be Rate HT.

- standard primary - unregulated alternating current, 60 hertz, nominally 2,400 volts, 2-phase, 3 wires, or nominally 4,160 volts, 3-phase, 3 or 4 wires. Availability of these voltages is limited to those locations served at these voltages as of July 6, 1987.

- standard high tension - unregulated alternating current, 60 hertz, nominally 13,200, 33,000, 69,000, 138,000, 230,000 or 500,000 volts, 3-phase, 3 or 4 wires (4-wire, 13 kV service is available in areas that have been converted to 13 kV distribution):

Where two or more such standard voltages are present in a given area, the Company will select the service voltage at which the required service can be supplied most economically. Nominally 13,200, 33,000, 69,000, 138,000, 230,000 or 500,000 volts as available in the various sections of the Company's service territory for loads of such character as to require supply at one of such voltages in order not to impose unsatisfactory service conditions on the Company's supply system, or for loads of such character that supply at one of such voltages is desired both by the Company and the customer. For service at Rate HT, where the customer's demand exceeds 7,000 kW, the customer may be required to provide a suitable property on or adjacent to their premises for the installation of Company's substation and transformation equipment.

The Company's charges for service, which are comprised of the Fixed Distribution Service Charge and Variable Distribution Service Charge, are non-bypassable and must be paid by any customer regardless of the voltage level at which the customer is served.

Service-supply lines - The facilities (conductors, cables, conduits, etc.) extending from the Company's facilities in the highway or other trunk line location to the facilities owned and maintained by the customer.

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DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS (continued)

Summary Billing Account - An aggregate bill prepared for two or more meter locations owned or legally controlled by the same partnership, association, corporation, or governmental agency etc. for: (1) the Company's charges for service; and/or (2) an EGS's charges for Competitive Energy Supply, as permitted by Rule 2.2.

Tariff - this Electric Service Tariff comprising the Base Rates, rules and regulations which in conjunction with Pennsylvania Public Utility Law and Pennsylvania Public Utility Commission Regulations govern the distribution of electric energy including all things done by the Company in connection with such distribution, and/or the supply of electric energy under Default Service, and other PaPUC jurisdictional services.

Variable Distribution Service Charge (Distribution Charge) - the variable supply charges for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

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RULES AND REGULATIONS

1. THE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and Default Service will be provided to its customers by PECO Energy, is on file with the Commission and is posted and open to inspection at the Principal Office of the Company. A copy of this tariff is also available on the Company's website at http://www.peco.com.

1.2 REVISIONS. This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the Pennsylvania "Public Utility Law", and such changes, when effective, shall have the same force as the present Tariff.

1.3 APPLICATION. The Tariff provisions apply to everyone lawfully receiving service from the Company, under the rates therein, and the recipient of service, whether service is based upon contract, agreement, accepted signed application, or otherwise, shall be subject to the terms of the Tariff. In addition, the rates therein shall apply to everyone receiving service unlawfully or otherwise, including unauthorized use as referred to in Rule 4.7 of this Tariff. A customer will receive service under the rates and riders of this tariff effective with their first scheduled billing cycle after the effective date of the tariff or as otherwise indicated in this tariff.

1.4 BASIS OF CHARGE. Time elapsed is a factor in the supply of service and the rates and minimum charges named in this Tariff, while predicated on periods of supply of not less than one year, are stated in values for direct application only to monthly periods of service supply and will be adjusted for application to service supplied during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable, unless specifically modified by a rate or rider provisions. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

1.6 USE OF RIDERS. The terms governing the supply of service under a particular Base Rate may be modified or amended only by the application of those standard riders, filed as part of this Tariff, which are specifically mentioned as applicable to that rate in the Applicability Index of Riders.

1.7 STATEMENT BY AGENTS. No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

2. SERVICE LIMITATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of electric energy of the standard characteristics available in the locality in which the premises to be served are situated. The Company does not offer to distribute and/or supply electric energy of nonstandard characteristics.

2.2 SINGLE-POINT DELIVERY The Company will provide standard distribution and/or supply through a single delivery and metering point for the total requirements at each separate premises of any person, partnership, association, or corporation, lawfully receiving service, except where, in the Company's sole judgment, special conditions warrant the installation of additional facilities. Unless otherwise stated herein, the Base Rates in this Tariff for each class of service are based upon that standard. Separate distribution and/or supply for the same customer at other points of consumption shall be separately metered and billed, except that: (1) when the Company is providing Consolidated EDC Billing, the Company will provide summary billing of its charges for and/or an EGS' charges (if requested by the EGS) for Competitive Energy Supply; and (2) when the Company is providing Separate EDC Billing, the Company will provide summary billing of its charges.

2.3 SINGLE-POINT AVAILABILITY. Service delivered at a single point is available to one or more buildings or units devoted essentially to a single purpose, provided and so long as:

(a) Such buildings or units are:
(1) held, possessed, and either utilized or operated as a single establishment by a single responsible entity, and
(2) unified on the basis of family, business, industry, enterprise, or governmental agency or through conveniences and services, such as heat, elevator, janitor, care of halls, walks and lawns, etc., furnished by such entity, and
(3) situated on a single or on contiguous land parcels except where such buildings or units constitute interdependent parts of a single industrial enterprise. In determining "contiguity" hereunder of parcels abutting opposite sides of public or private ways, the boundaries of such parcels shall be considered as extending to the center of such ways.

(b) There is granted and maintained to the Company easement or other rights, adequate in the Company's reasonable judgment to supply service direct to any such buildings or units if, as and when a cessation of any one or more of the conditions stated in paragraph lettered "a" above should occur, or there should arise in any manner a Company duty of such direct supply.

RULES AND REGULATIONS (continued)

(c) The transforming, receiving and distribution facilities on the customer's side of the delivery point, are:
(1) furnished, installed and maintained at the expense of the customer, and
(2) owned or leased by the customer, and
(3) operated and controlled by or at the expense of the customer.
(d) The Company is under no legal obligation of direct supply to any portion of said building or units or their appurtenances.
(e) A guarantee by deposit or otherwise is given and maintained to the Company sufficient in its reasonable judgment to insure it against loss in primary, secondary and/or distribution investment in the event of change in the nature of holding and possession of such buildings or units, or in the occupancy thereof, or in the type of service delivered thereto.
(f) All utilization equipment on the customer's side of the Company delivery point is furnished, installed, operated and maintained by the operator of the building or units supplied or by the tenants of such operator whose use of electricity is dependent upon the single-point delivery and metering of service.
(g) Any use of public highways by such operator for the latter's distribution facilities does not conflict or interfere with the franchise rights of the company.

2.4 COMPLIANCE WITH AVAILABILITY. The use of the Company's service shall not be for any purpose other than that covered by the availability provisions of the applicable Base Rate and/or riders.

2.5 SINGLE-PHASE UP TO 150 KVA. Single-phase secondary service is available for customer equipment with demand of or parallel-generation facilities having an aggregate nameplate rating up to 150 kVA. Any customer demand or generation equipment in excess of this amount will be supplied polyphase service. (The Company must approve the installation of parallel generation via an Interconnection Agreement before the customer operates that generation in parallel with the Company's distribution system.)

2.6 POLYPHASE LOADS AGGREGATING LESS THAN 7-1/2 HP. Polyphase service is not available for installations aggregating less than 7-1/2 horsepower, unless the excess cost of supplying polyphase rather a single-phase service is borne by the customer.

2.7 MOTORS. Service is not available to motors which do not meet the Company's standard requirements.

2.8 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Before receiving any electric service to or for new or renovated residential buildings or additions thereto, as defined by Pennsylvania Building Energy Conservation Act (BECA) as amended by Act 98 of 1985, applicants for service must provide the Company with the compliance certification copy of the Pennsylvania Department of Community Affairs (DCA) "Notice of Intent to Construct" form as processed by DCA. A compliance certification copy of "Notice of Intent to Construct" will not be required by the Company if the new or renovated residential building is located in a municipality which has elected to administer the BECA and requires that a notice of intent to construct be filed with the municipality before or at the time that application is made for a building permit and the notice has, in fact, been filed.

3. CUSTOMER INSTALLATION

3.1 INFORMATION FROM THE CUSTOMER. The Company should be advised by the customer or applicant for service, in writing, preferably on a form supplied by the Company, of premises to be equipped for service, giving exact location, and details of all current consuming devices to be installed.

The customer shall supply the Company any and all information in its possession regarding potential or actual contamination, waste or hazardous materials or other adverse environmental conditions on the customers' premises on or near where the Company facilities are to be located. The customer has a continuing obligation to provide the Company with such information relating to the premises as the customer receives it. The Company also has a continuing right to inspect the customers' premises for the purposes of performing an environmental assessment.

3.2 METER LOCATION. There shall be provided, free of expenses to the Company, at a location outdoors, unless otherwise designated by the Company or another AMSP, which the Company or another AMSP will designate in writing upon request, a suitable place for the meter or meters and any other supply, protective or control equipment of the Company or another AMSP which may be required in the provision of service. The customer shall provide access and space, in an amount deemed necessary by the Company, to install and maintain its meter(s) and equipment. This location shall be convenient, unimpeded and easily accessible to the Company's employees, contractors and agents. The Customer shall also minimize any risk for damage and/or harm to the Company's employees, contractors, agents and equipment at the meter location. There also must not be any impediment or obstruction of the Company's ability to receive, an adequate communication signal from its meter(s) for remote reading purposes. The meter(s) location shall also be situated so that the meter(s) are not concealed but shall be situated in a fashion acceptable to the Company.

3.3 POINT OF DELIVERY. The Company will designate in writing, upon request, a satisfactory point of delivery where the customer shall terminate the wiring and facilities for connection to the distribution lines of the Company. The failure to request and obtain such location may result in refusal of service pending rearrangement of customer's facilities, but the designation of a point of delivery does not constitute an agreement or obligation on the part of the Company to furnish service.

In establishing a point of delivery, the Company has the right to avoid areas known or suspected to contain contamination, waste or hazardous materials or other adverse environmental conditions. The customer will have the option of extending its own facilities to the

Company's point of service delivery.

The Company may waive this right of avoidance upon agreement by the customer or applicant to indemnify, defend, and hold harmless the Company (its successors, assigns, trustees, officers, employees and agents) from and against all actions, causes of action, claims and demands whatsoever, and from all costs, damages, expenses, losses, charges, debts and liabilities whatsoever

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RULES AND REGULATIONS (continued)

(including attorney's fees), whether known or unknown, present or future, that arise from such conditions. This indemnification provision shall survive the termination or expiration of said agreement and the termination of the business relationship of the parties thereto.

3.4 SERVICE ENTRANCE EQUIPMENT. All equipment beyond the point of delivery, except the meter, shall be installed by the customer. Installation shall be in conformity with the National Electrical Code and the Company's published "Electric Service Requirements", and shall include, where necessary, an approved sealable device for mounting a meter. The meter will be supplied, owned and sealed by the Company or another AMSP.

3.5 SECONDARY SERVICE CONNECTION. (a) Wiring of any premises for connection to overhead lines must be brought outside of the building wall to a location designated or approved by the Company, at which point the house wiring must extend at least 3 feet for attachment to the Company's service-supply lines. (b) Service connections to the Company's underground facilities shall terminate on the customer's premises in an approved connection box from which customer's wiring shall extend to the other service entrance equipment.

3.6 UNDERGROUND SERVICE. Customers desiring an underground service from overhead wires must bear the excess cost incident thereto. Specifications and terms for such construction will be furnished by the Company on request.

3.7 NONSTANDARD SERVICE. The customer or applicant for service shall pay the cost (includes related income taxes) of any special installation necessary to meet the unusual requirements of the customer or applicant for service, including but not limited to: (1) service at other than standard voltages, (2) service for loads that will be intermittent and which, in the Company's sole judgment, would not generate sufficient revenue to recover the installation costs of the required facilities, (3) service for loads that will be continuous but that will generate minimal usage, and which, in the Company's sole judgment, would not generate sufficient revenue to recover the installation costs of the required facilities, (4) service for loads that will require provision of closer voltage regulation than required by standard service, and (5) situations for which, in the Company's sole judgment, extenuating circumstances exist whereby the Company agrees to provide multiple services, which are not normally offered in other sections of the Tariff, to one customer located on a premises.

The customer or applicant shall pay all costs to the Company of performing environmental assessments, including, but not limited to, the cost of consultants utilized by the Company, the cost of removal and disposal of contamination, waste or hazardous materials or dealing with other adverse environmental conditions associated with either the initial installation, modification, repair, maintenance or removal of service facilities.

3.8 RELAY PROTECTION. The customer must install at the customer's own expense a reverse-phase relay of approved type on all alternating current motors for passenger and freight elevators, hoists, and cranes, and a reverse-power relay for parallel operation.

4. APPLICATION FOR SERVICE

4.1 METHOD OF APPLICATION. Customers may apply for service via the Company's website at http://www.peco.com or, in some cases, over the telephone.

4.2 SERVICE CONTRACT. Every applicant for service may be required to sign a contract, agreement, or other form then in use by the Company, covering the special circumstances of the use of service, and shall abide by these Rules and Regulations and the standard requirements of the Company including but not limited to those in PECO's Electric Service Requirements Manual ("Blue Book") Builder's Handbook, Interconnection Guidelines and other additional requirements that PECO will provide upon request.

4.3 CONTRACT DATA. The application shall contain a statement of the premises to be served, the rate under which service is desired, and such conditions or riders as are applicable to the special circumstances of the case.

4.4 RIGHT TO REJECT. The Company may place limitations on the amount and character of service it will supply or may reject applications for service: not available under a standard rate; which might affect service to other customers; which is to be delivered at a location or at a standard voltage that involves excessive cost; for bad credit; for the applicant's failure to provide identifying documentation; when an applicant's self-identification cannot be verified; or for other good and sufficient reasons. Customers cannot be denied Default Service or new service for failure to pay an EGS's charges.

The Company has the right to restrict service to only those locations which will not expose the Company to liability for known or suspected contamination, waste or hazardous materials or other adverse environmental conditions.

4.5 ACCEPTANCE. Before the Company affirmatively accepts an application, the Company will consider the application to be "pending". When an application is accepted, it constitutes the contract between the customer and the Company, subject to the Rules and Regulations. A customer or other recipient of service also becomes contractually obliged to the Company when service is provided according to the application either with or without modification, or when the customer otherwise receives service.

4.6 SPECIAL CONTRACTS. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, or where service is to be used for an emergency or temporary replacement of another method of operation, contracts of longer term than specified in the rate, or with special guarantees of revenue, or both, may be required.

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RULES AND REGULATIONS (continued)

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company. The use of service without notifying the Company or the AMSP and enabling them to read its meter will render the user liable for any amount due for service provided to the premises from the time of the last reading of the meter, immediately preceding the customer's occupancy, as shown by the Company's books.

4.8 WITHDRAWAL OF APPLICATION. In the event the customer (or potential customer) withdraws an application for either new or modified service, the customer will reimburse the Company for all reasonable costs incurred by the Company in anticipation of providing the new or modified service.

5. CREDIT

5.1 PAYMENT OBLIGATION. For customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing, the provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff (and, for the same class of service (residential or non-residential) under the Company's Gas Service Tariff, if the customer also receives gas service at the same premises) as applicable to the location and the character of service.

The Company may, at its discretion, determine liability for a past due balance by:

1) Use of Company records that contain information previously provided to the Company;
2) Information contained on a valid mortgage, lease, deed or renter's license;
3) Use of commercially available public records databases;
4) Government and property ownership records.

5.2 PRIOR DEBTS. Service will not be furnished to former customers until any indebtedness to the Company for previous service of the same or similar classification has been satisfied or a payment arrangement has been made on the debt. This rule does not apply to the disputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed; and (4) the customer nevertheless continues to dispute the same matter in bad faith.

5.3 GUARANTEE OF PAYMENTS. The Company may charge a security deposit before it will render service to an applicant or before the Company will continue to render service to a customer for whom the Company provides Consolidated EDC Billing or Separate EDC Billing. The Company may charge deposits to applicants and customers if they have bad credit, lack creditworthiness or as otherwise permitted by Commission statutes, rules, regulations, and as required by Federal Bankruptcy Law. The applicant or customer may be required to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company will hold the deposit as security for the payment of final bills and in compliance with the Company's Rules and Regulations. In addition, the Company may require industrial and commercial customers for which it may provide Consolidated EDC Billing or Separate EDC Billing to post a deposit at any time if the Company determines that the customer is no longer creditworthy or has bad credit or as otherwise permitted by Commission statutes, rules, regulations and as required by Federal Bankruptcy Law. The Company retains the right to charge customers additional deposits based upon continued bad credit or lack of creditworthiness and increased usage.

5.4 AMOUNT OF DEPOSIT. For residential customers, the deposit will be equal to one-sixth of the applicant's or customer's estimated annual bill for Company charges, based on applicable rates. A deposit from a residential customer shall conform to the requirements of 66 Pa. C.S. 1404(c) and applicable Pennsylvania Public Utility Commission regulations. For industrial and commercial accounts, the amount of the deposit shall be the Company's projection of the sum of the Company charges in the customer's two highest monthly bills in the 12 months following the deposit. The provisions of 11 U.S.C. §366(b) of the Federal Bankruptcy Code, or any successor statute or provision, shall, if inconsistent, supersede the provisions of this rule.

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RULES AND REGULATIONS (continued)

5.5 RETURN OF DEPOSIT. Deposits secured from a residential customer shall either be applied with interest to the customer's account or returned to the customer with interest in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations. In cases of discontinuance or termination of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Deposits secured from a residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 12 consecutive months. Deposits secured from a non-residential customer, plus accrued interest, which may be held until a timely payment history is established, are refunded when a ratepayer is not currently delinquent and has made on time and in full payments for service provided by the Company for 24 consecutive months. Any residential or commercial customer /having secured the return of the deposit may be required to make another deposit in accordance with Commission statutes, regulations or Federal Bankruptcy Law if the Customer demonstrates bad credit or lacks creditworthiness subsequent to the return of the initial deposit.

5.6 INTEREST ON DEPOSIT. The Company will allow simple interest on cash deposits calculated as follows:

(A) with respect to residential accounts, interest, will be computed at the simple annual rate determined by the Secretary of Revenue for interest on the underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as the Fiscal Code

(B) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent;

Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

5.7 CREDIT INFORMATION.

CUSTOMERS: In addition to information required otherwise hereunder, customers for whom the Company provides Consolidated EDC Billing or Separate EDC Billing shall be required to provide to the Company with such credit information, as the Company requires. The Company may report to a national credit bureau on credit history associated with past due amounts.

APPLICANTS: The Company's credit and application procedures for applicants are as follows: (1) positive identification of applicant obtained from previous customer record or through one of the major credit reporting bureaus; (2) determination of liability for a past due balance; (3) determination if a deposit is required based upon applicant's previous account history if available or through third party credit scoring of applicant.

The Company's credit scoring methodology and standards are as follows: The Company uses a commercially recognized credit scoring methodology that is within the range of generally accepted industry practice. The applicant's or customer's utility payment history determines the credit score. The Company uses this customer-specific credit score to either request or waive a security deposit.

5.8 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of this Rule 5, when a customer resides at a place of business or commercial establishment, legitimately served pursuant to a commercial or industrial rate schedule, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Pennsylvania Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to deposits for residential customers.

6. PRIVATE PROPERTY CONSTRUCTION

6.1 COMPANY'S SERVICE LINES. Where the Company has distribution facilities of adequate capacity on the highway or in other trunk line location adjacent to the premises to be served, it will provide, own and maintain standard service-supply lines as follows:

(a) UNDERGROUND:

Underground cable construction to a point of delivery approximately 18 inches inside the property line of the customer, except:

(1) For secondary service to new residences or new apartment buildings, underground cable construction will be extended to a meter location or connection box located at the building or buildings, as designated by the Company and in accordance with Rule 7.3.

(2) The Company will make necessary repairs to customer-owned extensions of primary and secondary underground service-supply lines for residential customers at no charge. If such customer-owned extension requires replacement, the Company will make the replacement and assume ownership of the service-supply line with the Company bearing the cost up to 200 feet in length and the customer bearing the cost for all additional length.

(b) AERIAL:

A single span of aerial open wire or cable construction to the first suitable support of the customer, nominally 100 feet inside the property line of the customer. This customer support shall establish the point of delivery for the customer. The customer's support shall be so located that the service span will be free of obstruction and adequately supported as required by the size and weight of the conductors.

6.2 SERVICE - SUPPLY ALTERATIONS. Changes related to a service-supply line or a meter owned by the Company, including the installation of protective devices or visual markers to denote safe operating distance from the Company's facilities, for the accommodation of the customer, shall be at the expense of the customer. If the alteration to the Company's facilities is temporary in nature and the materials used in that alteration can later by re-used by the Company, as for example the installation of protective "hard cover" to allow a customer, developer, or contractor to work safely in close proximity to the Company's facilities, then at the Company's discretion it may charge a refundable deposit in lieu of charging the customer for the cost of the re-usable materials.

6.3 CUSTOMER'S SERVICE EXTENSION. The customer shall provide, own, inspect and maintain the service extension from the Company's service-supply lines to the point of delivery and receiving equipment. PECO may install a Company-owned meter, transformer (which transformer may serve one or more customers), or other required equipment, of its choice, on customer-owned property or facilities; Such installation does not alter the responsibility of the customer to provide, own, inspect, and maintain the required customer service extension to which such Company-owned facilities may be attached.

6.4 METERS AND TRANSFORMERS. The Company will provide, own and maintain any meter or meters, and also the transformer or transformers (both potential and current type transformers), required in the supply of service of the current characteristics specified by the Base Rate or rider under which the service is provided, unless the customer receives Advanced Meter Services from an AMSP in that case such AMSP will install, provide, own, and/or maintain the Customer's meter or meters while the Company will continue to own the potential and current type transformers. The supply of transformers by the Company shall be limited to those required for a single standard transformation.

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RULES AND REGULATIONS (continued)

6.5 TRAILER PARKS. Where it is established by plans, development, use or other facts that the operation of a trailer park is predominantly to provide rental locations for non-transient trailers, with not less than two nor more than four such locations, the Company, upon written application of the trailer park operator and upon the receipt of an enabling agreement and of adequate rights-of-way, will construct, own and operate within the trailer park specified aerial electric energy, the trailer park operator being liable for payment of service to trailer park tenants not contracting in writing for service in their own names. The Company's obligation to install or extend such distribution facilities within the trailer park is limited to the investment warranted by the anticipated revenue. Alterations of such distribution facilities at the request of the park operator when not for the purpose of serving additional trailer rental locations will be at the cost of the trailer park operator. A trailer park operator desiring underground distribution facilities within a trailer park consisting of less than five locations must bear the excess cost incident thereto. Specifications and terms for such underground construction will be furnished by the Company on request. In new trailer parks consisting of five or more locations, underground distribution facilities will be extended in accordance with Rule 7.3.

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RULES AND REGULATIONS (continued)

7. **EXTENSIONS**

7.1 TRUNK LINE CONSTRUCTION. The Company will construct, own and maintain overhead or underground distribution facilities, either secondary, primary, or high tension, located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general distribution system.

7.2 LINE EXTENSIONS FOR STANDARD SERVICE.

A. DEFINITIONS. For the purposes of this rule, when capitalized herein, the below terms shall have the following meanings:

(1) Line Extension -- A single-phase or polyphase addition to the public utility electric supply line for the purpose of supplying standard service (as described under Rule 2 above, but not including Line Extensions for nonstandard service as described in Rule 3.7 above) to and connected with the customer's point of delivery which addition is so located that it cannot be supplied by means of a service line from the existing electric supply line.

(2) Contractor Cost -- The amount paid by the Company to a contractor for work performed on a Line Extension.

(3) Customer -- End use customer of the Company, or a developer.

(4) Direct Labor Cost -- The pay and expenses of the Company employees directly attributable to work performed on Line Extensions, but not including construction overheads or payroll taxes, workmen's compensation expenses or similar indirect expenses.

(5) Direct Material Cost -- The purchase price of materials used for a Line Extension, but not including related storage expenses. In computing Direct Material Costs, proper allowance shall be made for unused materials, materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.

(6) Total Construction Cost -- For single-phase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, and Direct Material Cost. For polyphase Line Extensions, the estimated total cost to the Company for the construction of the Line Extension, which cost shall include: Contractor Cost, Direct Labor Cost, Direct Material Cost and allocated overheads. For projects requiring significant design work, the Company will provide a preliminary cost estimate and charge customers a non-refundable deposit of 10% of the total estimated costs to fund the detailed design work. The detailed design work cost will not be included in the Total Construction Cost of the Line Extension used to determine contribution in aid of construction ("CIAC").

(7) Capacity Adjusted Cost -- For polyphase Line Extensions, the Total Construction Cost of a Line Extension multiplied by the percentage of that Line Extension's capacity installed to serve the Customer's capacity needs.

(8) Revenue Guarantee Contribution -- The estimated Variable Distribution Service Charges, as defined in the "Definitions of Terms and Explanation of Abbreviations" Section of this tariff, to be received by the Company from the Customer for a twelve (12) month period commencing with the first month after the Line Extension is completed.

B. SINGLE-PHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a single-phase Line Extension as follows. The Company will construct a Line Extension up to 2,500 feet without a charge to the Customer. For Line Extensions over 2,500 feet, a Customer shall pay the Company a contribution in aid of construction ("CIAC") equal to the amount by which the Total Construction Cost of the Line Extension beyond 2,500 feet exceeds the Customer's Revenue Guarantee Contribution for the first three (3) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the single-phase Line Extension.

C. POLYPHASE LINE EXTENSIONS FOR STANDARD SERVICE. For a Customer whose use of the Line Extension is not speculative, the Company will construct a polyphase Line Extension, as follows. A Customer must pay the Company a CIAC equal to the amount by which the Capacity Adjusted Cost of the Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. A Customer who is not a developer must pay the CIAC in full prior to the construction of the polyphase Line Extension.

D. DEVELOPERS. Prior to the construction of any Line Extension, a developer may, in lieu of paying the full CIAC, pay a minimum of 35 percent (35%) of the CIAC and, for the remaining amount, post a surety bond in a form reasonably acceptable to the Company. The unpaid portion of the CIAC is subject to interest at the then applicable prime rate and is payable no later than twelve (12) months from the date of the initial payment.

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RULES AND REGULATIONS (continued)

E. SPECULATIVE LINE EXTENSIONS. A Line Extension is speculative when, in the Company's reasonable opinion there is doubt: (1) as to the continued use, or the level of use, of the new Line Extension by the Customer; or (2) as to the Company's recovery of the Total Construction Cost for a polyphase Line Extension if a Capacity Adjusted Cost is applied.

Under the first scenario of a speculative Line Extension, the Company will construct the Line Extension for a Customer, as follows: pursuant to an individual contract between the Customer and the Company, in addition to any CIAC, the Customer may be required to provide the Company a customer advance in the form of an up-front payment, or, if mutually agreed to by the Customer and the Company, a cash deposit, letter of credit, surety bond or other guarantee, satisfactory to the Company, in the amount of the lower of the Total Construction Cost or the Customer's Revenue Guarantee Contribution used in the CIAC calculation as set forth in Part B or C above, as applicable ("Customer Advance"). If, after three (3) years for a single-phase Line Extension, or five (5) years for a polyphase Line Extension, the Customer's Variable Distribution Service Charges have met or exceeded the Customer Advance, the Company will either: (1) return the Customer Advance to the Customer if an up-front payment has been made; or (2) terminate the Customer's obligation to maintain the cash deposit, letter of credit, surety bond or other guarantee.

Under the second scenario of a speculative Line Extension, the Company will construct a polyphase Line Extension for a Customer, as follows: the Customer must pay the Company a CIAC equal to the amount by which the Total Construction Cost of the polyphase Line Extension exceeds the Customer's Revenue Guarantee Contribution for the first five (5) year period after the Line Extension is completed. The Customer may receive a refund of all or part of the CIAC paid if, during that five (5) year period, additional Customers have connected to the Line Extension for which the Customer paid the CIAC. The refund, if any, will be calculated based on the load of the connecting Customers.

7.3 UNDERGROUND SERVICE IN NEW RESIDENTIAL DEVELOPMENTS.

A. For the purposes of this rule, and in accordance with 52 Pa. Code § 57.81, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

1. Applicant For Electric Service - The developer of: a recorded plot plan consisting of five or more lots; or one or more five-unit apartment houses.
2. Developer - The party responsible for construction and providing improvements in a development; that is, streets, sidewalks, and utility-ready lots.
3. Development - A planned project which is developed by a developer/applicant for electric service set out in a recorded plot plan of five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, mobile homes, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.
4. Distribution Line - An electric supply line of untransformed voltage from which energy is delivered to one or more service lines.
5. Service Line - An electric supply line of transformed voltage from which service is delivered to the residence.
6. Subdivision - A tract of land divided by a subdivider into five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or apartment houses, all of which are intended for year-around occupancy, if electric service to such lots necessitates extending the Company's existing distribution lines.

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RULES AND REGULATIONS (continued)

B. INSTALLATION OF DISTRIBUTION AND SERVICE LINES. All distribution and service lines installed pursuant to an application for electric service within a development will be installed underground, and will be owned and maintained by the Company. Pad-mounted transformers may be installed at the option of the Company. Excavating and backfilling will be performed by the developer of the project or by such other agent as the developer may authorize. The developer or its agent may also for the purpose of reducing civil work costs, install conduit for the Company's use in installing electrical service, if the conduit and associated excavation work meets PECO's requirements. The Company will then assume ownership of such conduit. Installation of service-related facilities will be performed by the Company or by such other agent as the Company may also be installed underground, upon terms and conditions prescribed elsewhere in this tariff. The Company will not be liable for injury or damage occasioned by the willful or negligent excavation breakage, or other interference with its underground lines occasioned by anyone other than its own employees or agents.

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Nothing in this section shall prohibit the Company from performing its own excavating and backfilling for greater system design flexibility. However, no charges other than those specified in Section 57.83(4) of Title 52 shall be permitted.

C. APPLICANTS FOR SERVICE. The applicant for service to a development shall conform with the following:

(1) At its own cost, provide the Company with a copy of the recorded development plot plan identifying property boundaries, and with easements satisfactory to the Company for occupancy by distribution, service and street-lighting lines and related facilities.

(2) At its own cost, clear the ground in which the lines and related facilities are to be laid of trees, stumps and other obstructions, provide the excavating and backfilling subject to the inspection and approval of the Company, and rough grade it to within six inches of final grade, so that the Company's part of the installation will consist only of laying of the lines and installing other service-related facilities. Excavating and backfilling performed or provided by the applicant will follow the Company's underground construction standards and specifications set forth by the Company in written form and presented to the applicant at the time of application for service and presentation of the recorded plot plan to the Company. If the Company's specifications have not been met by the applicant's excavating and backfilling, such excavating and backfilling will be corrected or redone by the applicant or its authorized agent. Failure to comply with the Company's construction standards and specifications permits the Company to refuse utility service until such standards and specifications are met.

(3) Request service at such time that the lines may be installed before curbs, pavements and sidewalks are laid; carefully coordinate scheduling of the Company's line and facility installation with the general project construction schedule, including coordination with any other utility sharing the same trench; keep the route of lines clear of machinery and other obstructions when the line installation crew is scheduled to appear; and otherwise cooperate with the Company to avoid unnecessary costs and delay.

(4) Pay to the Company any necessary and additional costs incurred by the Company as a result of the following:

a) Installation of underground facilities that deviate from the Company's underground construction standards and specifications if such deviation is requested by the applicant for electric service and is acceptable to the Company.
b) A change in the plot plan by the applicant for electric service after the Company has completed engineering for the project and/or has commenced installation of its facilities.
c) Physical characteristics such as oversized lots or lots with extreme set-back where under the Company's line extension policy contained in this tariff a change is mandated for overhead service.
d) The Company will require developers to provide financial security in advance for all developments prior to Company installation of distribution and service lines. At the time of execution of the contract between the developer and the Company, the developer shall post a letter of credit, surety bond, or other security, satisfactory to the Company equal to 50% of the value of the Total Construction Cost as defined by the Company under Section 7.2A(6). If the developer does not fully develop the lots within five years, including, but not limited to, installing all required electric meters and flowing electricity to them, the Company reserves the right to use the security for reimbursement of all distribution and service line installation costs.

(5) No charges other than those described in paragraph (4) of this subsection shall be borne by the applicant for electric service or by any other utility sharing the same trench, even if the Company elects to perform its own excavating and backfilling.

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D. APPLICABILITY. The provisions of this rule will apply to all applications for service to developments, herein before defined, which are filed after the effective date of this tariff.

E. SUBDIVISIONS. Underground facilities in new residential developments are only required by Sections 57.81 through 57.87 of Title 52 when a bona fide developer exists, i.e., only when utility-ready lots are provided by the developer. A mere subdivision is not required to have underground service. However, should the lot owner or owners in a subdivision desire underground service, such service shall be provided by the Company if such lot owner or owners, at their option, either comply with Section 57.83 of title 52, or pay to the Company such charges as are contained in the Company's tariff for service not required by Title 52.

7.4 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES. All contributions in aid of construction (CIAC), customer advances or other like payments received by the Company shall constitute taxable income as defined by the Internal Revenue Service. The income taxes on such CIAC or customer advances will be segregated in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with CIAC or customer advances will not be charged to the specific contributor of the capital. Rule 7.4 is applicable to all CIAC or other like payments received for standard services.

8. RIGHTS-OF-WAY

8.1 TERM AND RENTALS. When the premises of a customer is so located that the customer can be served only by facilities extending over the property of another, the customer shall accept service for such term as is provided in a permit or other applicable agreement covering the location and the maintenance of service equipment, and shall reimburse the Company for any and all special or rental charges that may be made for such rights by said permit or agreement.

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RULES AND REGULATIONS (continued)

8.2 PROCUREMENT BY CUSTOMER. Customers applying for the construction of an extension may be required to secure to, and for, the Company, all necessary and convenient rights-of-way and to pay any associated costs.

8.3 DELAYS. Applications for service from an extension to be constructed where a right-of-way is not owned by the Company will only be accepted subject to delays incident to obtaining a satisfactory right-of-way.

9. INTRODUCTION OF SERVICE

9.1 WIRING IN PROGRESS. Service-supply lines will not be installed before the time that the customer's wiring of the premises is actually in progress.

9.2 INSPECTION. The Company reserves the right to refuse the introduction of service unless a written certificate of approval, satisfactory to the Company, has been received from a competent inspection agency authorized to perform this service in the specific locality in which service is to be provided.

9.3 COMPANY'S RIGHT TO INSPECT. The Company shall have the right, but shall not be obliged to inspect, any installation before it begins to deliver electricity or at any later time, and reserves the right to reject any wiring or appliances not in accordance with the Company's standard requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the installation, wiring, or appliances, or from violation of Company rules, or from accidents which may occur upon the premises of the customer.

9.4 DEFECTIVE INSTALLATION. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

9.5 UNSATISFACTORY INSTALLATION. The Company may refuse to connect if, in its judgment, the customer's equipment, or use thereof, might injuriously affect the equipment of the Company, or the Company's service to other customers.

9.6 FINAL CONNECTION. The final connection between the customer's installation and the Company's service lines shall be made by or under the supervision of a representative of the Company, except for standard single-phase secondary aerial service, in which case the customer may make the final connection in accordance with the Company's standard requirements.

9.7 NEW OR TRANSFER CUSTOMER CHARGE. When a customer's account for service is initiated or when a customer's account is transferred from one address to another address, there will be a charge of $6.00 to cover the clerical expenses incurred by the

Company. The State Tax Adjustment Clause applies to this charge.

10. COMPANY EQUIPMENT

10.1 COMPANY MAINTENANCE. The Company shall keep in repair and maintain its own property installed on the premises of the customer.

10.2 CUSTOMER'S RESPONSIBILITY. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property the customer shall pay the costs of repairs and replacement. Any changes made to the Customer's premises after the Company completes its service and meter installation that, in the opinion of the Company, creates an unsafe condition, shall be the Customer's responsibility to pay any costs associated with remedying the unsafe condition including, but not limited to, any required protective measures and/or relocations of Company property.

Customers with privately owned or operated underground utility facilities on their premises may have obligations as facility owners under the Underground Utility Line Protection Act, 73 P.S. Section 176 et. seq. These include becoming a member of Pennsylvania One Call, maintaining said facilities, and providing approximate locations of said facilities with temporary markings within the required time period in response to Pennsylvania One Call notifications. Customers should create and retain as-built drawings reflecting the locations of said facilities on the premises and revise these drawings as necessary to reflect any changes made following installation. If said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work, the Company has the right to require the associated customer to bear all incremental costs necessary to ensure safe digging by the Company, including but not limited to subsurface utility excavation and engineering, materials, supplies, transportation, labor, and overhead. If 1) said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work or 2) the Company is unable to notify a facility owner of its intent for excavation or similar work covered under the Act because the facility owner is not a member of the Pennsylvania One Call system, the Company shall not be liable to customers or any other third parties for any damages, including property damage, economic damages, costs, associated consequential damages or personal injuries.

10.3 PROTECTION BY CUSTOMER. The customer shall protect the equipment of the Company on the premises, and shall not permit any person, except a Company employee having standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter or other apparatus of the Company located on the customer's premises.

10.4 TAMPERING. In the event of the Company's meters or other property being tampered or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations.

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RULES AND REGULATIONS (continued)

10.5 RIGHT OF ACCESS. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. In the event of an emergency, the Company shall have the right to access customer owned facilities and equipment for the purpose of restoring electric service, for the purpose of rendering the electric facilities safe and reliable, or for the purpose of reducing the likelihood of damage to the Company's facilities and equipment.

10.6 OWNERSHIP AND REMOVAL. All equipment supplied by the Company shall remain its exclusive property, and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service from whatever cause.

10.7 POLE REMOVAL OR RELOCATION REQUESTED BY RESIDENTIAL PROPERTY OWNERS. The cost for removal or relocation of distribution line poles and their associated attachments made pursuant to the request of a residential property owner who is not entitled to receive condemnation damages to cover the cost of such work shall be borne by the property owner and shall be limited to contractor, direct labor, and direct material costs incurred less maintenance expenses avoided as a result of the pole removal or relocation. The calculation of such cost for removal or relocation shall be in accordance with the Public Utility Commission Regulations - Title 52, Section 57.27.

RULES AND REGULATIONS (continued)

10.8 RELOCATION OF COMPANY FACILITIES REQUESTED BY NON-RESIDENTIAL PROPERTY OWNERS. Except as otherwise provided by law (e.g., 66 Pa.C.S. Section 2704, et seq.), a non-residential property owner, such as a builder, developer or contractor (Owner), shall pay to the Company the costs of relocation of Company facilities or equipment, made for the accommodation of the Owner or in fulfillment of the Owner's obligation to any public authority. If the facility relocation is made to accommodate the Owner's project or in fulfillment of the Owner's obligation to any public authority, then the Owner shall be responsible to pay PECO for the relocation costs even if the relocation request is made by an entity other than the Owner. A request for relocation of Company facilities shall be in writing. The relocation cost shall include labor (including overhead), materials, storeroom expense and transportation, less the depreciated value of any equipment replaced. Where the relocation is done in conjunction with construction of a supply line to a development, the Company shall include in the relocation cost only those costs caused by the Owner's request. The Company will notify the Owner in writing of the relocation cost. Advance payment of relocation costs will be required before the Company will commence the work, except, at the sole discretion of the Company, under special circumstances.

Where the relocation relates to a development that will generate additional revenue for the Company, the Company will give the Owner an initial credit against the relocation costs in an amount not to exceed 5% of the estimated annual revenue recovered through the Company's tariffed Variable Distribution Service Charges from the portion of the development under construction at the time of the relocation request. The Company will give the Owner an additional credit against relocation costs not to exceed 5% of the estimated additional revenue recovered through the Company's tariffed Variable Distribution Service Charges realized from new load on the PECO Energy system due to buildings not under construction at the time of the initial relocation but that are under roof within a five (5) year period from the date of completion of the relocation work. Credits will be held by the Company and distributed to the owner, on a pro-rated basis, as additional loads from the development are connected to PECO Energy's distribution system. No credits will be given for loads connected after the five year period from the date of completion of the relocation work. When the relocation is done in conjunction with extension of a line in accordance with §7.2 of the Tariff, the Company will include in the credit calculation only such estimated annual revenue that exceeds the minimum revenue guarantee required by §7.2. The cost and expense of project changes which require a second relocation of the same Company facilities shall be borne solely by the party requesting the change without offset or credit.

10.9 AERIAL LINE CLEARANCE. In accordance with the requirements set forth in the National Electrical Safety Code, the Company shall have the right to trim, remove, or separate trees, vegetation or any structures therein which, in the opinion of the Company, interfere with its aerial conductors, such that they may pose a threat to public safety or to system reliability.

10.10 ADVANCED METER SERVICES PERFORMED BY AMSPs. The provisions of this Rule 10 are subject to the terms of the Electric Generation Supplier Coordination Tariff.

10.11 RECOVERY FOR PROPERTY DAMAGE. If Company equipment is damaged through the negligence or intentional act(s) of any individual(s) or entity(s), the one(s) responsible for causing the damage shall reimburse the Company for all aspects of the resulting damages. The reimbursement shall include costs related to: labor, material, transportation and tools. "Labor" shall include benefit and administrative overheads based on the Company's current standard schedule, including third party contract repairs or modifications. Additionally, "Labor" may be calculated using a "blended" or average pay rate consistent with the above referenced standards. "Materials" may include an added stores expense calculated using the above referenced standards.

11. TARIFF AND CONTRACT OPTIONS

11.1 CHOICE OF RATE. When the class of service-supply or conditions of use are such that two or more Base Rates are available, a customer shall select the Base Rate on which the customer will be billed.

11.2 COMPANY ASSISTANCE. The Company upon request will, to a reasonable extent, assist customers in selecting the most advantageous Base Rate or rate application (i.e., Base rate together with applicable riders).

11.3 RATE CHANGES. A customer may not change Base Rates during the "initial contract term" as defined in the "Definition of Terms and Explanation of Abbreviations" section above unless the Company agrees to permit the change. At any other time, a customer may change to a firm rate for which the customer qualifies upon 30 days notice to the Company. Customer ownership and obligation to maintain customer owned transformation facilities and equipment, as well as the point of delivery, will be unaffected by any Base Rate change initiated by the customer.

A customer may request that the Company modify the terms of its contract, other than the customer's Base Rate, but the Company will only allow such modification when, in the Company's sole judgment, the modification does not conflict with the Company's Tariff and is not detrimental to the Company.

The Company will not make any Base Rate change retroactive, unless, in the Company's sole judgment, the Company failed to adequately respond to a customer's request for assistance or modification at the time of such request.

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RULES AND REGULATIONS (continued)

12. SERVICE CONTINUITY

12.1 LIMITATION ON LIABILITY FOR SERVICE INTERRUPTIONS AND VARIATIONS. The Company does not guarantee continuous, regular and uninterrupted supply of service. The Company may, without liability, interrupt or limit the supply of service for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public or for the purpose of preventing or limiting any actual or threatened instability or disturbance of the system. The Company is also not liable for any damages due to accident, strike, storm, riot, fire, flood, legal process, state or municipal interference, or any other cause beyond the Company's control.

In all other circumstances, the liability of the Company to customers or other persons for damages, direct or consequential, including damage to computers and other electronic equipment and appliances, loss of business, or loss of production caused by any interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity 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 $1000 or two times the charge to the customer for the service affected during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs. In addition, no charge will be made to the customer for the affected service during the period in which such interruption, reversal, spike, surge or variation in supply or voltage, transient voltage, or any other failure in the supply of electricity occurs. A variety of protective devices and alternate power supplies that may prevent or limit such damage are available for purchase by the customer from third parties.

The Company makes no warranty as to merchantability or fitness for a particular purpose, express or implied, by operation of law or otherwise. To the extent applicable under the Uniform Commercial Code or on any theory of contract or products liability, the Company limits its liability in accordance with the previous paragraph to any Customer or third party for claims involving and including, but not limited to, strict products liability, breach of contract, and breach of actual or implied warranties of merchantability or fitness for an intended purpose.

12.2 ADDITIONAL LIMITATIONS ON LIABILITY IN CONNECTION WITH DIRECT ACCESS. Other than its duty to deliver electric energy and capacity, the Company shall have no duty or liability to a customer receiving Competitive Energy Supply arising out of or related to a contract or other relationship between such a customer and an EGS.

The Company shall implement customer selection of an EGS consistent with applicable rules of the Commission and shall have no liability to a customer receiving Competitive Energy Supply arising out of or related to switching EGSs, unless the Company is negligent in switching or failing to switch a customer.

The Company shall have no duty or liability with respect to electric energy before it is delivered by an EGS to a point of delivery on the PECO Energy distribution system. After its receipt of electric energy and capacity at the point of delivery, the Company shall have the same duty and liability for distribution service to customers receiving Competitive Energy Supply as to those receiving electric energy and capacity from the Company.

12.3 EMERGENCY LOAD CONTROL. Pursuant to order of Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff:

Whenever the demands for power on all or part of the Company's system exceed or threaten to exceed the capacity than actually and lawfully available to supply such demands, or whenever system instability or cascading outages could result from actual or expected transmission overloads or other contingencies, or whenever such conditions exist in the system of another public utility or power pool with which the Company's system is interconnected and cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system, a load emergency situation exists. In such case, the Company shall take such reasonable steps as the time available permits to bring the demands within the then-available capacity or otherwise control load. Such steps shall include but shall not be limited to reduction or interruption of service to one or more customers, in accordance with the Company's procedures for controlling load.

The Company shall establish procedures for controlling load including schedules of load shedding priorities to be followed in compliance with the foregoing paragraph, may revise such procedures from time to time, and shall revise them if so required by Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at the Company's Principle Office, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.4 EMERGENCY ENERGY CONSERVATION. Pursuant to order of the Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff:

Whenever events occur which are actually resulting, or in the judgment of the Company threaten to result, in a restriction of the fuel supplies available to the Company or its energy suppliers, such that the amount of electric energy which the Company is able to supply is or will be adversely affected, an emergency energy situation exists.

In the event of an emergency energy conservation situation, the Company shall take such reasonable measures as it believes necessary and proper to conserve available fuel supplies. Such measures may include, but shall not be limited to reduction, interruption, or suspension of service to one or more of its customers or classes of customers in accordance with the Company's procedure for emergency energy conservation.

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RULES AND REGULATIONS (continued)

The Company shall establish procedures for emergency energy conservation, including, if it deems necessary, schedules of service interruption and suspension priorities to be followed as prescribed by the foregoing paragraph.

The Company may revise such procedure from time to time, and shall revise them if so required by the Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its Tariff for public inspection, and another such copy shall be kept on file with the Pennsylvania Public Utility Commission.

12.5 NOTICE OF TROUBLE. The customer must immediately notify the Company if service is interrupted or is otherwise unsatisfactory due to defects, trouble, or accident, affecting the supply of service.

12.6 RELOCATION OF DELIVERY POINT. In the event that the Company shall be required by any public authority to place underground any portion of its mains, wires, or service-supply lines, or relocate any poles or feeders, the customer, at the customer's own expense, shall change the location of his point of delivery to a point readily accessible to the new location.

RULES AND REGULATIONS (continued)

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. Pursuant to Section 1313 of the Public Utility Code, 66 Pa. C.S. § 1313, a customer may resell Energy and Capacity and/or service provided by PECO Energy under its default service plan if: (1) the Company provides such service under a single contract at one application of an available Base Rate and for the total requirements of the premises served, and (2) the location and use of the service conforms to the availability requirements of this Tariff for provision to the customer for the customer's own account.

All residential units connected after May 10, 1980, except those dwelling units under construction or under written contract for construction as of that date must be individually metered by either the Company, the AMSP or the landlord for their basic electric service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation. The bill rendered by the reseller to any consumer shall not exceed the amount which PECO Energy would bill its own residential customers for the same quantity of service under the applicable tariffed residential rate.

The requirements for individually metered dwelling units in new construction may be waived at the sole discretion of the Company. Such waiver will only be granted when the owner can demonstrate to the Company that there are valid reasons for such waiver and that there will not be a significant impact on the consumption of an individual customer.

In accordance with the Commission's Policy Statement at Docket No. M-2017-2604382, the electricity sales by a person, corporation or other entity, not a public utility, owning and operating an electric vehicle charging facility for the sole purpose of recharging an electric vehicle battery for compensation shall not be construed to be sales to residential consumers and therefore do not fall under the pricing requirements of 66 Pa.C.S. § 1313. Such sales are therefore not considered a resale of service as defined in this tariff rule, Rule 13.1.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned charging station, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

13.2 FLUCTUATIONS. Electric service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and, in the case of violation of this rule, the Company may discontinue service, or require the customer to modify the installation and/or equip it with approved controlling devices.

13.3 TYPE OF INSTALLATIONS. Motor and other installations connected to the Company's lines must be of a type to use minimum starting current and must conform to the requirements of the Company as to wiring, character of equipment, and control devices.

13.4 UNBALANCED LOAD. The customer shall at all times take, and use, energy in such manner that the load will be balanced between phases to within nominally 10%. In the event of unbalanced polyphase loads, the Company reserves the right to require the customer to make the necessary changes at the customer's expense to correct the unsatisfactory condition, or to compute the demand used for billing purposes on the assumption that the load on each phase is equal to that on the greatest phase.

13.5 ADDITIONAL LOAD. The service connection, transformers, meters and equipment supplied by the Company for each customer, have definite capacity, and no additions to the equipment or load connected thereto will be allowed except by consent of the Company.

13.6 CHANGE OF INSTALLATION. The customer shall give immediate written notice to the Company of any proposed increase or decrease in, or change of purpose or location of, the installation.

13.7 FAILURE TO GIVE NOTICE. Failure to give notice of additions or changes in load or location shall render the customer liable for any damage to the meters or their auxiliary apparatus, or the transformers, or wires, of the Company, caused by the additional or changed installation.

14. METERING

14.1 SUPPLY OF METERS. An EGS that is also an AMSP may provide Advanced Meter Services in accordance with the Electric Generation Supplier Coordination Tariff. Otherwise, subject to Rules 14.3 and 14.9, the measurement of service for billing purposes shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment to be used for meters supplied by the Company, and may, from time to time, change or alter the equipment, its sole obligation being to supply meters that will accurately and adequately furnish records for billing purposes. In fulfilling its obligations with respect to metering and meter reading, and with respect to AMSPs that provide Advanced Meter Services, the Company will comply with Electric Generation Supplier Coordination Tariff.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, reactive-component meters, or other instruments, on the premises of any customer except for any customer for whom an AMSP is providing Advanced Meter Services, for the purpose of measuring the demand and/or the power factor, or for other tests of all, or any part, of the customer's load.

14.3 CUSTOMER REQUEST FOR SPECIAL METER. If a customer for whom the Company is providing either metering and meter reading wishes to replace its billing metering equipment, to the extent technically possible, the Company may offer, provide and support a selection of qualified meters and may perform installation within a reasonable amount of time and at the expense of the customer. The customer must pay for any such metering equipment based on the net incremental cost of purchasing and installing the new metering equipment as approved by the Commission. The Company will own and maintain all such new metering equipment.

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RULES AND REGULATIONS (continued)

14.4 POWER FACTOR MEASUREMENT. For customers for whom the Company is providing metering and meter reading or Advanced Meter Services, the Company reserves the right to measure the power factor of the customer's load, either by test or by permanently installed instruments. For customers for whom an AMSP is providing Advanced Meter Services, the Company reserves the right to require such AMSP to measure the power factor of the load of the customer on the same basis the Company measures the power factor of customers for which the Company provides metering and meter reading or Advanced Meter Services.

14.5 REVERSE REGISTRATION. The Company may, by ratchet or other device, control its meters to prevent reverse registration.

14.6 ESTIMATED USAGE. The kilowatt-hours and billing demands to be paid for may be determined by computation instead of by measurement in the case of installations having a fixed load or demand value controlled to operate for a definite number of hours each day.

14.7 METER READING INTERVALS. The Company will read its meters in accordance with Appendix C to the Joint Petition for Full Settlement and at scheduled regular intervals of one month. Monthly customer usage will not be prorated for seasonality. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render standard bills for the recorded use of service based upon the time interval between meter readings. EGS & EDC charges shall be based on the EDC defined meter reading route schedules. Only those bills which cover a period of service of less than 26 days or more than 35 days will be prorated. The Company will reflect multiple supplier switches within a single monthly bill to ensure a customer can switch their electric service in accordance with the accelerated switching process final omitted rulemaking order that amends 52 Pa. Code, Ch. 57.172 – 57.179. See Dockets No. L-2014-2409383 and P-2014-2446292.

14.8 ESTIMATED USAGE. For customers for whom the Company provides meter reading or Advanced Meter Reading Services, the Company shall estimate the amount of service supplied to premises where access to the meter is not available or if such estimate is necessary, and to installations at remote locations when warranted by the type of installation, regularity of usage, or other circumstances. For customers for whom it provides Consolidated EDC Billing or Separate EDC Billing, the Company will render bills in standard form based on such estimate and so marked, for the customer's acceptance. Meter readings will be secured from time to time and billing will be revised when they disclose that the estimate failed to approximate the actual usage. For residential customers, an actual meter reading will be obtained at least every six months in accordance with Commission regulations.

14.9 CUSTOMER SELECTED ADVANCED METERS. A customer may request either PECO Energy or an AMSP to have an Advanced Meter installed and have Advanced Meter Services provided pursuant to Appendix C of the Joint Petition for Full Settlement and any applicable rules adopted by the Commission. For an advanced meter to be deployed in the PECO Energy service territory, it must be included in the Commission's Advanced Meter Catalog, and indicated as eligible for deployment in the PECO Energy territory.

14.10 MANUAL METER READING FEE Upon customer request, the Company will secure an in-person meter reading to confirm the accuracy of an automatic meter reading when a customer disconnects service or a new service request is received. The fee is $45 and the Company will include this fee on the customer's or applicant's bill.

15. DEMAND DETERMINATION

15.1 MEASURED DEMANDS. Measured demands may be quantified by recording or indicating instruments showing, unless otherwise specified, the greatest 30-minute rate-of-use of energy, provided that in the case of hoists, elevators, welding machine, electric furnaces, or other installations where the use of electricity is intermittent or subject to violent fluctuation the demand may be fixed by special determination.

15.2 DEMAND DETERMINATION.

(a) Special Determination. Where charges specified in this Tariff are based upon the customer's demand, it is intended that such demand shall fairly represent the customer's actual demand that the Company must stand ready to serve. In the case of installations where the customer's regular use of service in the ordinary course of the customer's business is such that measurement over a thirty-minute interval does not result in a fair or equitable measure of the customer's demand, then the demand may be estimated from the known character of use and the rating data of the equipment connected, or from special tests. The intent of this provision is that the demand so determined shall fairly represent the demand that the Company must stand ready to serve.

(b) Demand Waiver. When a customer wishes to conduct a test of equipment or process that is not part of the customer's normal operations, the customer may request that the Company waive the demand caused by that test, if that demand is the highest measured demand in the billing month. The Company will agree to such a waiver if the following conditions are met:

1. The Company's metering is of a type which allows for the determination of 30-minute demands; and
2. The customer's request is in writing, and is received by the Company at least 15 business days before the date of the commencement of the proposed test. The request must specify the nature of the test, the size of the loads to be tested and the starting and ending times; and
3. The Company determines that the tests are not a part of the customer's normal operations; and
4. The test will not last for more than twelve (12) consecutive hours; and
5. The customer has not conducted a test and received a demand waiver for a test pursuant to this rule within one year of the proposed test.

Upon receipt of a request for a demand waiver, the Company will inform the customer in writing within fifteen (15) days of receipt of the customer's request whether it will grant the proposed waive

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RULES AND REGULATIONS (continued)

15.3 POWER FACTOR ADJUSTMENT.

A. Standard Power Factor Values (based on measured demands)

Measured Demands (Kw)	Standard Power Factor
0 -185	80%
186 - 2,500	90%
Over 2,500	95%

B. Adjustment to Measured Demand. When a customer's measured power factor is less than the standard power factor values above, the Company shall increase the customer's measured demand by the ratio of the standard power factor to the measured power factor. The Company will then use this adjusted demand as a basis for calculating the customer's billing demand in accordance with the applicable rate schedule.

C. Determining Measured Power Factor:

1) For customers with measured demands of 750 kW or greater in three consecutive months:

(a) Until metering equipment capable of continuous power factor measurement is installed, the Company shall determine measured power factor based C3 below.
(b) Once capable metering is installed, the Company shall continuously measure power factor.
i. The customer's measured power factor shall coincide with the customer's maximum measured demand.

ii, The Company in its sole judgment may discontinue continuous power factor measurement if: (1) the customer's measured demand is less than 750 kW for twelve consecutive months, or: (2) the Company determines that changes to the customer's load characteristics will result in that customer permanently reducing measured demand to less than 750 kW.

2) For customers with measured demands of less than 185 kW:

(a) If the Company in its sole judgment deems that that the power factor is likely to be less than this standard based on the customer's load, the Company shall determine measured power factor based on C3 below.
(b) Otherwise, the Company shall assume the customer's measured power factor to be the standard noted above

3) For all other customers, including those with measured demands between 185 kW and 750 kW, the Company shall determine measured power factor in one of the following ways:

(a) By test, at a time when the customer's load is at least two-thirds of the customer's maximum measured demand in the preceding eleven months.
(b) At the option of either the customer or the Company, by measurement as determined from meters installed by the Company, ratcheted to prevent reverse registration.
i. Customers requesting measurement of power factor shall be subject to a monthly meter charge determined in accordance with the cost of the meter installation. Such installation shall not be for less than one year.
ii. When meters are installed, the measured power factor shall be the power factor that is coincident with customer's maximum measured demand.

4) A customer that receives Advanced Meter Services from an AMSP is subject to these rules regarding determination of measured power factor.

16. METER TESTS

16.1 METER TESTS. The Company at its expense, will make periodic tests and inspections of its meters in order to maintain them at a high standard of accuracy.

16.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a customer or an EGS providing Competitive Energy Supply to a customer, but reserves the right to make the charge provided for in the Electric Regulations of the Pennsylvania Public Utility Commission, under conditions therein specified.

16.3 ADJUSTMENT FOR ERROR. Should any of the Company's meters become defective or fail to register correctly, the use of electricity shall be determined by a test of any such meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount registered for the preceding billing period and the amount registered during not less than one week immediately subsequent to the repairs to, or change of, the meter, taking into consideration the character of use by the customer.

16.4 RESIDENCE METER ERRORS. Meter errors in the Company's meters in residence service may be determined on the basis of the registration of the corresponding period during the preceding year, if records are available and conditions of use remain the same.

16.5 ADMINISTRATION TESTS. The Company, at its own expense, will make only such tests of the Company's meters as it deems necessary for the proper administration of its rates, or as are required by law.

16.6. TESTING SERVICE. The Company will, upon request by the customer, make tests of the Company's meters to supply special information regarding the customer's use of service, provided that the estimated cost of such special tests shall be paid by the customer to the Company at the Company's discretion.

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RULES AND REGULATIONS (continued)

17. BILLING AND STANDARD PAYMENT OPTIONS

17.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its delivery. The customer will be billed in accordance with rule 14.7. Rate values stated for direct application to monthly billing periods will be adjusted when time elapsed between readings is substantially greater or less than a month.

17.2 BILLING OPTIONS. A customer may select one of the following three billing options as communicated to PECO by the customer's supplier: (1) Consolidated EDC Billing; (2) Consolidated EGS Billing; and (3) Separate EDC/EGS Billing, as those terms are defined herein. If a customer does not make a selection, the customer shall receive Consolidated EDC Billing. When the Company provides Consolidated EDC Billing or Separate EDC Billing, it will comply with the terms and conditions of the Electric Generation Supplier Coordination Tariff.
For customers who receive both electric and gas service from the Company, the Company will issue a bill that contains charges for both of these services.

17.3 PAYMENT.

(a) The Company's bills to customers are payable upon presentation. Payment for service received must be made on or before the due date shown on the bill. The due date shall be determined by the Company and shall be not less than twenty days from the date of transmittal of the bill for Rates R, R-H, RS-2, POL and GS (excluding Summary Billing Accounts). The due date shall be not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts. Notwithstanding the foregoing, the due date may be up to thirty days for accounts (including Summary Billing Accounts) with the United States of America, the Commonwealth of Pennsylvania, or any of their departments, political subdivisions, or instrumentalities. The Company may allow a reasonable amount of additional time for payment of bills on industrial and commercial accounts of creditworthy customers. If the due date that appears on a customer's bill falls on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not operating, the due date shall be extended to the next business day. The payment period will not be extended because of the customer's failure to receive a bill unless said failure is due to the fault of the Company.

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(b) Payment may be made at any authorized payment agency. The customer bears the risk of delivery of payment tendered on or after the date contained in any termination notice sent to the customer.

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(c) The Company may require that a customer that is not creditworthy tender payment by means of a certified, cashier's, teller's, or bank check, or by wire transfer, or in cash or other immediately available funds.

(d) A customer must pay the undisputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed, and (4) the customer nevertheless continues to dispute the same manner in bad faith.

17.4 PAYMENT PROCESSING. When the Company is providing Consolidated EDC Billing, Default Service or Separate EDC Billing, and the customer remits a partial payment to the Company, the payment will be applied as follows:

1. Any past due balances including those for prior PECO basic service charges, for prior EGS receivables purchased by the Company, for prior installment amounts on payment agreements, and also for any reconnection charges.
2. Any current charges including those for PECO basic service charges, for current EGS receivables purchased by the Company, and for current installment amounts on payment agreements.
3. Non-basic service charges.

17.5 LATE FEES AND COLLECTION COSTS. If payment is made at an authorized payment agency after the due date shown on the bill, a late fee will be added to the unpaid balance until the entire bill is paid. If payment is made by mail, the late fee will be added if the payment is received by the Company more than five days after the due date shown on the bill. For Rates R, R-H, RS-2, POL and GS this late fee will be 1-1/2 % per month; for all other rates the late fee will be 2% per month. The Company will not apply late fees to Final Bills as defined in Tariff Rule 20.2. If the Company files suit to collect a delinquent balance on an account (whether active or inactive) or to ensure payment of current bills, the customer will be required to pay the Company's out of pocket court costs (including filing, service, and witness fees) as ordered by the court and such costs will be added to commercial and industrial accounts.

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17.6 BUDGET BILLING.

(a) At the option of a customer receiving residential service under Rates R, R-H, RS-2, and GS, an estimated total bill for all service to be received by the customer over a twelve month period may be budgeted over the period and an average bill rendered monthly for payment each month. Any difference between the budgeted amounts so paid and the actual charges for a twelve month budget period will at the customer's option, either be amortized over the next twelve months or incorporated into the 12th month bill. Absent an indication of preference from the customer, the debit or credit will be amortized. Budget billing may be discontinued upon the customer's request at which time any difference between budget billing amounts and actual charges becomes due and payable. If a monthly budget bill is not paid, a late fee will be added to the unpaid balance of actual charges on the next billing date in accordance with Rule 17.3 and 17.5. Any such late fee will be calculated based on the lesser of budget billing arrears and actual charged arrears The Company may also arrange budget billing for creditworthy commercial and industrial customers.

(b) When the Company provides Consolidated EDC Billing, the EGS's charges will be included in the customer's Budget Billing Plan.

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RULES AND REGULATIONS (continued)

17.7 CALCULATION OF LATE FEE. Where a late fee is applicable, the amount of the late fee to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid late fees, by the appropriate late fee rate.

17.8 TAX EXEMPTION. If a customer is tax exempt, the customer must provide a tax exempt form to PECO Energy and to its EGS, regardless of which billing option the customer chooses.

17.9 BILLING ERRORS. When the Company provides Consolidated EDC Billing, PECO Energy shall not be responsible for billing errors resulting from incorrect price information received from an EGS.

17.10 RETURNED PAYMENT CHARGE. If a check (electronic or paper) received in payment of a customer's account is returned to the Company unpaid or if upon a second attempt by the Company or its agent for payment the check is again returned unpaid, then the Company will add a returned payment charge to the customer's account in the amount of **$20.00.**

17.11 APPLICABILITY TO CUSTOMERS RESIDING AT PLACE OF BUSINESS. For purposes of all of the provisions of Rule 17, when a customer resides at a place of business or commercial establishment legitimately served pursuant to a commercial or industrial Base Rate, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to payment terms for residential customers.

18. PAYMENT TERMS & TERMINATION OF SERVICE

18.1 NON-PAYMENT TERMINATION. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the customer is subject to collection action, including termination of service (in accordance with the Pennsylvania Public Utility Code or the Commission's regulations, on the portion of the past due amount attributable to the Company's charges for: (1) service, (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered to be "reasonable" hereunder

18.1.1 WINTER TERMINATIONS FOR NON-PAYMENT. Consistent with 52 PA Code §56.100, The Company will take the following steps for terminations for non-payment during the winter period, defined as December 1-March 31:

A. **Low-Income Eligibility:** The Company will use financial information provided by the Customer to determine if the Customer's income is at or below 250% of the Federal Poverty Level. The Company may elect to send to the Customer an income verification form for completion and return. The Company will also accept income verification provided by Community-Based Organizations that enter into a contract with PECO to provide such income verification services.

1. Annual income may be established using verified income information for a recent one-month (nominally 30-day) period, annualized to establish an estimated annual income.
2. The Company shall not require any customers who have established income eligibility for winter termination protections within the 12 months preceding the start of the winter period to re-certify or re-verify their income for that winter period. This Company may also use this information to determine deposit requirements, payment arrangements, and eligibility for any other income-specific program.

B. **Verified Low-Income Customers:** If the Company has received verified proof that a customer's household has income at or below 250% of the Federal Poverty Level, the Company will not pursue termination of that customer for non-payment during the winter period UNLESS (A) the Company receives Commission approval to do so via a petition filed pursuant to 52 Pa. Code §56.100(g), or (B) the customer has informed the Company after submitting this verification that the household no longer has income at or below 250% of the Federal Poverty Level.

For purposes of this section, the Company will accept the following as verified proof that the household has income at or below 250% of the Federal Poverty Level:

1. Enrollment in PECO's CAP program at any time within four years prior to the issuance of the winter termination notice;
2. Receipt of a LIHEAP grant at any time within four years prior to the issuance of the winter termination notice;
3. Receipt of a MEAF grant at any time within four years prior to the issuance of the winter termination notice;
4. Income verification provided by a CBO that has contracted with PECO to provide income verification information, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
5. Other verified documentation that the household's income is at or below 250% of the Federal Poverty Level, as long as such documentation was received within four years prior to the issuance of the winter termination notice;
6. Receipt of verified documentation of low-income status in response to an Income Inquiry Letter, as described in Rule D.1 below.

C. **Verified Non-Low-Income Customers:** If the Company has received verified proof that a customer's household has income of greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

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RULES AND REGULATIONS (continued)

D. **Customers with Non-Verified Income Levels:** For all other customers, prior to proceeding with termination for non-payment, the Company will send the customer a letter (the "Income Inquiry Letter") informing the customer that the Company does not have verified income information for the customer and that the customer is subject to termination for non-payment during the winter period.

1. If the customer responds with verified income information demonstrating that the household income is at or below 250% of the Federal Poverty Level, the Company will treat that household as Verified Low-Income for purposes of winter termination;
2. If the customer responds with verified income information demonstrating that the household income is greater than 250% of the Federal Poverty Level, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.
3. If the customer fails to respond to the Income Inquiry Letter or responds without providing verified income information, the Company will attempt to contact the customer via telephone to inform the customer of their duty to provide verified income information. If contact is made and verified income information is not provided by the customer, or if contact is not made, the Company will pursue termination for non-payment during the winter period utilizing the termination notices and procedures that would be followed outside of the winter period.

18.2 PAYMENT TERMS. When the Company is providing either Consolidated EDC Billing or Separate EDC Billing, the Company will in accordance with Pennsylvania Public Utility Law and applicable Pennsylvania Public Utility Commission Regulations and Orders, negotiate payment arrangements on the portion of the past due amount attributable to its charges for: (1) service (2) Energy and Capacity and (3) to Customer EGS Receivables purchased by the Company. However, the Company will not negotiate payment arrangements on behalf of an EGS.

18.3 TERMINATION FOR CAUSE. The Company may terminate on reasonable notice if entry to the meter or meters is refused or if access thereto is obstructed or hazardous; or if utility service is taken without the knowledge or approval of the Company; or for other violation of these Rules and Regulations and/or applicable Commission rules, including those found at Pennsylvania Public Utility Code or the Commission's regulations.

18.4 SAFETY TERMINATION. The Company may terminate without notice if the customer's installation has become hazardous or defective.

18.5 DEFECTIVE EQUIPMENT TERMINATION. The Company may terminate without notice if the customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other customers; or if a certificate of approval is refused after a re-examination of the customer's installation by a competent inspection agency authorized to perform this service in the specific locality where service is provided.

18.6 TERMINATION FOR FRAUD. The Company may terminate without notice for abuse, fraud, material misrepresentation of the customer's identity, or tampering with the connections, the Company's meters, or other equipment of the Company.

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RULES AND REGULATIONS (continued)

18.7 RECONNECTION CHARGE. If service is terminated or discontinued by reason or act of the customer, the same customer, whether an applicant or a customer as defined at 66 Pa. C.S. § 1403, shall pay a reconnection charge prior to restoration of service at the same address within twelve months after discontinuance or termination. The reconnection charges, listed below, are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs. All theft reconnections will be completed at the premise and will not be performed remotely.

	Reconnect Fees
Electric Reconnect at the Meter	**$ 75.00**
Electric Reconnect at Tap	**$ 260.00**
Electric Reconnect - Underground dig	**$ 1,650.00**
Electric with dual meters	**$ 100.00**
Electric Remote Reconnect (one or dual meters)	**$ 20.00**

Beginning April 2028, the Company will waive the Electric Remote Reconnect (one or dual meters) fee ($20.00 per reconnection) for all customers who were disconnected due to nonpayment and who have demonstrated annual household gross income at or below 150% of the Federal Poverty Level through one or more of the following means : (1) provided verified financial information (i.e., proof of income documentation) in the last two years; and/or (2) currently enrolled in the Customer Assistance Program ("CAP"); and/or (3) received a Low-Income Home Energy Assistance Program ("LIHEAP") grant in the last two years.

18.8 THEFT INVESTIGATION CHARGE. If the Company establishes that there has been confirmed active theft resulting from tampering with the Company meter on the customer's premises, and the customer is or was a customer as defined at Pa. C.S. § 1403 the customer shall pay a theft investigation charge in addition to any amount that the Company establishes is due for service used, but not registered on the Company's meter. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 18.7.

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	Theft Investigation Fees
Electric Theft at Meter	**$400.00**

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RULES AND REGULATIONS (continued)

19. UNFULFILLED CONTRACTS

19.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service before the expiration of a contract term will not relieve a customer from any minimum, or guaranteed, payment under any contract or rate. In the case of residential customers this Rule only applies if the customer has signed an express written contract that clearly sets forth such a term and condition of service.

19.2 COMPLETION OF TERM. If, by reason of any act, neglect or default of a customer, the Company's service is suspended, or the Company is prevented from providing service in accordance with the terms of any contract it may have entered into with the customer, the minimum charge for the unexpired portion of the initial contract term shall become due and payable immediately as liquidated damages. These liquidated damages may, at the option of the Company, be offset by estimated revenues from a succeeding customer at the same location, if such exists.

20. CANCELLATION BY CUSTOMER

20.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service from the Company must give the Company at least 7 days' written notice to that effect.

20.2 FINAL BILL. The customer is liable for service taken after notice to terminate the contract, until the meter is read and/or disconnected. The final bill for service is then due.

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RULES AND REGULATIONS (continued)

21. GENERAL

21.1 OFFICE OF THE COMPANY. Wherever, in this Tariff, it is provided that notice be given or sent to the Company, or the office of the Company, such notice, delivered or mailed, postage prepaid to any commercial office, shall be deemed sufficient, unless the Principal Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

21.2 NO PREJUDICE OF RIGHTS. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to do so.

21.3 GRATUITIES TO EMPLOYEES. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

21.4 BILLING CHANGES. Where billing changes are made as the result of an investigation made at customer's request or by routine inspection, the change of billing may be applied to the bill for the regular meter reading period preceding such investigation, and will, in any event apply to the bill for the period during which the investigation is made.

21.5 EXCEPTIONAL CASES. The usual supply of electric service shall be subject to the provisions of this Tariff; but where special service-supply conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its supply terms to meet the peculiar requirements of such case, provided that such modified terms are a rational expansion of standard tariff provisions.

21.6 ASSIGNMENT. Subject to the Rules and Regulations, all contracts made by the Company shall be binding upon, and oblige and inure to the benefit of, the successors and assigns, heirs, executors and administrators of the parties thereto.

21.7 OTHER CHARGES. The Company may, if feasible, provide and charge for services, other than those provided for in this Tariff, when requested by the customer. The Company is not obligated to provide such services. The Company will, if possible, give the customer an advance written estimate of the costs to provide the service. Costs shall include, but not be limited to, materials, supplies, labor, transportation and overhead.

21.8 TAX INDEMNIFICATION. If PECO Energy becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, 66 C.S. §§ 2806(g) and 2809(c), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify PECO Energy for the amount of additional state tax liability imposed upon PECO Energy by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Reform Code of 1971 or Chapter 28 of Title 66.

22. RULES FOR DESIGNATION OF PROCUREMENT CLASS

22.1 DESIGNATION OF PROCUREMENT CLASS

a) Annually, in November the Company shall notify the customer of their procurement group class designation which shall be effective the following June 1.
b) The procurement class designation shall be used to determine the appropriate Generation Supply Adjustment to apply to the customer.
c) For non-residential customers, the procurement class shall be determined based upon the customers peak measured demand in the prior June-May period.
d) There shall be three procurement class designations. They are:
   1)Residential
   2)Small Commercial and Industrial up to and including 100 kW
   3)Large Commercial and Industrial greater than 100 kW
e) Procurement class designation shall only change once per year on the date established in rule 22.1a
f) A new customer in a new facility shall be assigned to a procurement class based upon an engineering estimate of the customer's diversified peak demand.
g) A new customer in an existing facility shall be assigned to the same procurement class as the last customer in that facility unless the new customer will use the existing facility in a substantially different manner.

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RULES AND REGULATIONS (continued)

23. EGS SWITCHING

23.1 PECO Energy will accommodate requests by customers to switch EGSs on active accounts and pending active (Instant Connect) accounts in accordance with this Rule 23, Commission Order M-2014-2401085, and other applicable Commission Orders.

23.2 To switch to a new EGS, a customer must inform the new EGS. Customers that wish to switch are not required to contact PECO Energy to initiate a switch; PECO Energy will only switch a customer in accordance with Rule 23.

23.3 To enable a new EGS to complete a switch, a customer must provide to the new EGS the customer's PECO Energy Electric Choice ID number as it appears on the customer's PECO Energy monthly bill.

23.4 If a Customer contacts the Company to discontinue electric service and indicates that the Customer will be relocating outside of the Company's service territory, the Company will notify the current EGS of the Customer's discontinuance of service for the account at the Customer's location. If relocating within the Company's service territory the Company will seamlessly move the current EGS to the new location if all qualifications are met in accordance with PUC Order M-2014-2401085.

23.5 A switch to an EGS will be effective 3 business days after the enrollment request is processed, provided the enrollment request includes valid customer information as required by the controlling provisions of the Supplier Tariff. Upon receiving valid notice to switch an EGS, the Company shall notify the customer's existing EGS that such a request has been made.

23.6 If and when a customer's EGS discontinues its supply in the event of bankruptcy, loss of license, or similar occurrence, or if a Customer is dropped by its EGS for non-payment or other reason then the customer may select a new EGS. The customer will receive its energy supply from PECO Energy until the switch becomes effective.

23.7 Nothing in this Rule 23 shall be interpreted to preclude EGSs from entering into agreements for supply with a term of service of one month. EGSs may enter into agreements for longer.

23.8 The Company will send Release of Information packets to all new customers (except for customer with demands greater than 500kW), which information will provide customers the opportunity to authorize the release of their confidential account information. PECO annually notifies customers that they can change this authorization. Every three years, in accordance with PUC Docket No. M-2010-2183412, PECO will re-solicit its entire customer base (except for customer with demands greater than 500kW) for the purpose of opting out of disclosing information.

24. LOAD DATA EXCHANGE

24.1 PECO Energy will provide to a customer or the customer's designated EGS or authorized consultant, all available data from the meter once each calendar year for no fee. The exchange of data among PECO Energy, EGSs, and customers shall be in accordance with the Supplier Tariff and the Final Consensus Plan for Electronic Data Exchange Standards for Electric Deregulation in the Commonwealth of Pennsylvania, as approved by the Commission.

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STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this tariff, a credit value of 0.04% will apply to all PaPUC jurisdictional distribution charges in the Base Rates and Riders, effective January 1, 2026.
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Whenever any of the tax rates used in the calculation of the surcharge are changed, or recoveries are authorized under Sections 2806, 2809 or 2810 of the Competition Act, the surcharge will be recomputed as prescribed by the Commission. The recalculation will be submitted to the Commission within ten days after the change occurs and the effective date shall be ten days after filing.

In addition, if a recalculation is submitted as a result of a tax rate change (including the Revenue Neutral Reconciliation rate) the Company will thereafter file each year by December 21 annual updates or revisions with the Commission which will reflect only this tax change. These annual updates will be effective ten days after filing and will continue until such time as the effect of the change in tax rates has been included in base rates.

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Purpose: The purpose of this surcharge is to refund to customers amounts of incremental COVID-19 related uncollectible accounts embedded in PECO's current rates. ¶
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Applicability: The surcharge shall be calculated to the nearest one-hundredth of a cent for billing purposes for all R and RH customers, for customers on all other rates it shall be the nearest one cent. The ICUS will become effective upon the effective date of rates for the electric distribution base rate case at Docket No. R-2024-3046931 for a period of one year. The ICUS shall be credited to each rate schedule as follows:¶
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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW

Applicability: June 1, 2025 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below.

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next semi-annual period beginning with the six months ended November 30, 2025.

The rates in this tariff shall be updated semi-annually on June 1 and December 1 commencing June 1, 2025 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula:

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where;

C= The sum of the amounts paid to the full requirements suppliers providing the power for the semi-annual period, the spot market purchases for the semi-annual period, plus the cost of any other energy acquired for the semi-annual period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the component above for the semi-annual period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods June 1 through November 30 of the current year and December 1 of the current year through May 31 of the following year.

A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods June 1 through November 30 of the current year and December 1 of the current year through May 31 of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00069/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.10237
RH	GSA (1)	$0.10237
GS	GSA (2)	$0.09325

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

PD	GSA (2)	$0.09166
HT	GSA (2)	$0.08792
POL*	GSA (2)	$0.06726
SL-S*	GSA (2)	$0.06726
TLCL	GSA (2)	$0.09325
SL-E*	GSA (2)	$0.06726
AL*	GSA (2)	$0.06726
SL-C*, **	GSA (2)	$0.06726

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1 and December 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. (Customers electing this option are billed based on interval-metered consumption of usage within each TOU Pricing Period. Beginning and ending reads are not applicable TOU billing determinants.) Commencing June 1, 2025, TOU Pricing Option rates will be updated semi-annually in concurrence with the Standard GSA on June 1 and December 1 and are not prorated.

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] from June 1, 2025 through May 31, 2026 are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12,73%	14.15%	6.06-to-1	4.85-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	19.76%	20.35%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	67.51%	65.50%	1.44-to-1	1.47-to-1

Commencing with the GSA and TOU rates effective June 1, 2022, PECO may update the TOU Pricing Multipliers in the above table annually, using a rolling five years of historical PJM Day-Ahead Spot Market Pricing energy data and Reliability Pricing Model capacity pricing data for the PECO zone. PECO will **only** update the applicable TOU Pricing Multipliers if the use of such data would result in no more than a 10% change from the prior-year's TOU Pricing Multipliers. If these updates would exceed 10%, the applicable TOU Pricing Multipliers will be changed by exactly 10%.

To calculate the semi-annual TOU Pricing Option rates, the Company will first calculate the semi-annual TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the semi-annual TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

Current TOU Pricing Option Charges:

TOU Rate	Peak ("PP") (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak ("SOPP") (12-6 AM all days)	Off-Peak ("OPP") (All other times)
R (GSA 1)	$0.31960	$0.05274	$0.07595
RH (GSA 1)	$0.31960	$0.05274	$0.07595
GS (GSA 2)	$0.24405	$0.05032	$0.07397
PD (GSA 2)	$0.23993	$0.04947	$0.07272
HT (GSA 2)	$0.23013	$0.04745	$0.06975

TOU Eligibility Requirements and Switching Rules:

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2025 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw.

Hourly Pricing Service
Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2025 and are not prorated. If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

$$\Sigma PJM_{DA} \text{ x usage / (1-LL)}$$

PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution

RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

$$((PJM_{AS} \text{ x Usage}*1/(1\text{-LL}) + AEPS/S_{AEPS} \text{ x Usage})$$

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_{3/4}$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_{3/4}$ = Procurement class 3/4 sales
WC = $0.00069/kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP
Hourly Pricing Adder* (dollars/kWh)	$0.00131	$0.00121	$0.00098	$0.00098

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

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RECONCILIATION

Applicability: June 1, 2025 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing.

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2024 through December 31, 2024 reconciliation period. There will be a transition reconciliation period for Procurement Classes 1 and 2 effective June 1, 2025 through November 30, 2025. The reconciliation will be based on utilizing the December 31, 2024 over/(under) balance adjusted for prior period revenues from January (C) 2025 through May 2025. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. For Procurement Classes 1 and 2, any over/(under) recovery shall be collected after the occurrence of five months from the end of the reconciliation period. Recovery shall be over a six month period commencing June 1 and December 1. The initial six month period is June 1, 2025 through November 30, 2025. For Procrement Class 3/4 Hourly, any over/(under) recovery shall be collected after the occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2025 through August 31, 2025. For purposes of this rider the reconciliation shall be calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 –Residential, Class 2 – Small C&I up to and including100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class.

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:

E = Experienced over or under collection plus associated interest

N = Procurement class

M = Migration Rider

O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

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RECONCILIATION
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Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by five months for Procurement Classes 1 and 2 and two months for Procurement Class 3/4 Hourly . For Procurement Classes 1 and 2,the GSA will be effective June 1 and December 1 commencing June 1, 2025 with over/under collection recovery occurring over the six month period beginning June 1 and December 1. For Procurement Class 3/4 Hourly, the GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2025 with over/(under) collection recovery occurring over the six month period beginning September 1 and March 1. The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits.

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NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE (NDCA)

The NDCA provides for the recovery of nuclear of decommissioning costs related to the Company's Ownership interest in Nuclear Generation as of 12/31/99. The NDCA shall be charged to all customers taking service under this Tariff. The adjustment shall be a cents per kWh charge calculated to the nearest one hundredth of one cent.

The Company's Ownership interest in nuclear generation as of December 31, 1999 consists of the following:

Peach Bottom 1	100%
Peach Bottom 2	42.49%
Peach Bottom 3	42.49%
Salem 1	42.59%
Salem 2	42.59%
Limerick 1	100%
Limerick 2	100%

Formula

The following formula shall be used to determine the NDCA.

$$NDCA = \frac{\text{PaPUC Authorized Decommissioning Expense Adjustment}}{\text{Total Pennsylvania Jurisdictional Sales for Calculation Year}}$$

Where:

PaPUC Authorized Decommissioning Expense Adjustment (Adjusted Annual Accrual - Base Accrual) x .95 = the Adjusted Annual Accrual in the Calculation Year less the Base Accrual. As of January 1, 2023, the NDCA shall be a credit value of ($0.0006)/kWh and will be added to the Variable Distribution Charge for all rates except for rates POL, SL-S and AL which will have a credit value of ($0.04)/location added to the Distribution Charge.

Total Pennsylvania Retail Jurisdictional Sales = total kWh sales under this Tariff for the calculation year including sales for distribution.

Calculation Year = year in which the Company proposes a change to the NDCA. To the extent a new cost study, performed every five years, indicates the Company requires an adjustment in the rate, the Company shall change the NDCA to reflect such new expense level. In calculating the annual expense, the Company shall use the sinking fund methodology.

Adjusted Annual Accrual = accrual necessary to fund the Adjusted Obligation.
Adjusted Obligation = Gross Decommissioning Obligation reduced by $50 million for ratemaking purposes.
Gross Decommissioning Obligation – The total decommissioning cost obligation as approved by the Commission as expressed in escalated future dollars.

Methodology for Calculating Expense

The base period expense shall be based upon the decommissioning costs set forth in the table below. The Company shall use a sinking fund methodology to determine the appropriate level of decommissioning expense. The assumptions shall be consistent with NRC policy and requirements.
The Base Accrual shall consist of the following levels for each unit.

Peach Bottom 1	$4,213,220
Peach Bottom 2	0
Peach Bottom 3	0
Salem 1	0
Salem 2	0
Limerick 1	0
Limerick 2	0
Total	$4,213,220

Frequency of Calculation

The annual expense shall be recalculated every five years. The Company shall adjust the NDCA to reflect the new expense level 60 days after filing the new study and the associated rate calculation with the PaPUC. The first calculation of the NDCA shall be considered to have taken place on January 1, 1998.

Completion of Decommissioning

In the event that the actual expenditures necessary to accomplish full decommissioning of the PECO Interest are less than the full balance in the funds established for such purpose, PECO shall be entitled to a release of such funds to PECO for the purpose of sharing the amount between ratepayers and shareholders. In the event that such release is granted, PECO's shareholders shall be entitled to retain: (1) the first $50 million of the net after-tax amount; and (2) 5 percent of the remaining net after-tax amount of the released funds.

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PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for electric service in Residential Rate Schedule R and RH of this Tariff shall include a charge of $0.00287 per kWh for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below pursuant to Section 2804 (8) of the Competition Act. The USFC rate for electric service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below.

COMPUTATION OF USFC.
The USFC per kWh ($0.0000), shall be computed in accordance with the formula set forth below:

$$USFC = \frac{(C+L-E-I)}{(S)}$$

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedules identified above. The amount of USFC, per kWh, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per kWh, pursuant to the formula above, the following definitions shall apply:

Reconcilable Customer Assistance Program (CAP) Costs – The difference between (A) the sum of discounts provided to CAP customers (CAP revenue shortfalls) and forgiven Pre-Program Arrearages recovered through base rates, and; (B) the sum of actual total CAP discounts and actual forgiven Pre-Program Arrearages, net of an offset factor applied on a monthly basis as follows:

1. PECO will compare the actual month-end CAP participation level to the baseline CAP participation level most recently approved by the Commission within a Company distribution rate case proceeding to determine the CAP participation above or below the baseline for that month. (The Company's current baseline CAP participation level is 145,721 participants, approved under Docket Number R-2026-3060859.)
2. PECO will calculate the actual average CAP discount per customer for that month, dividing the actual amount of discounts by the actual month-end CAP participation level.
3. PECO will multiply the results of Items 1 and 2 above together to obtain the portion of the offset basis related to CAP discounts above or below the approved baseline.
4. PECO will compare the actual month-end Pre-Program Arrearage forgiven to one-twelfth of the baseline Pre-Program Arrearage level most recently approved by the Commission within a Company distribution rate case proceeding to determine the Pre-Program Arrearage forgiven above or below the baseline for that month. (The Company's current baseline Pre-Program Arrearage Forgiveness level is $17,845,130, approved under Docket Number R-2026-3060859.) The result will be the portion of the offset basis related to Pre-Program Arrearage forgiveness.
5. PECO will calculate the monthly offset by applying the offset factor percentage most recently approved by the Commission within a Company distribution rate case proceeding to the sum of Items 3 and 4 above. (The Company's current offset factor percentage is 11.9%, approved under Docket Number R-2026-3060859.)

USFC – Universal Service Fund Charge to be included in the rate for each kWh of Variable Distribution Service Charge calculated under Rate Schedules R and R-H to recover Reconcilable CAP Costs plus certain LIURP related expenditures.

C - Cost in dollars of the Reconcilable CAP Costs for the projected period.

L - Incremental LIURP related expenditures not included in base rates. This shall include an additional $500,000 increase expenditures for LIURP Health and Safety program and up to $200,000 expenditures for De Facto Heating program beginning in 2027 in the annual budget of LIURP program costs.

E - The net overcollection or (undercollection) of Universal Service Fund Charges. The net overcollection or undercollection shall be determined for the most recent period, beginning with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Included in the "E" factor will be Reconcilable CAP Costs, and LIURP related expenditures. Included in the E factor calculation is the reconciliation of Pre-Program Arrearages, effective January 1, 2027.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous USFC.

I - Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period. The interest calculation will not apply to LIURP amounts.

S - projected kWh of electric service to be billed under Rate R and Rate RH (exclusive of CAP Rider) during the projected period when rates will be in effect.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.
The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective January 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

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PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's proposed consumer education plan. The proposed plan shall consist of the cost of the consumer education plan approved in Docket M-2008-2032274, P-2008-2062739 and R-2024-3046931.

Applicability: The surcharge shall be a per customer charge calculated to the nearest one cent, which shall be added to the fixed distribution rates for billing purposes for all customers. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is a 5.0 cent charge per month for Rates R, RH and CAP, Class 2 and 3 is a 0.0 cent per month for Rate GS and for Class 4 is 0.0 cent credit per month for Rates HT and PD with an April 1, 2025 effective date.

Billing Provisions: The surcharge shall be calculated on an annual basis using the following formula:

$$MC(n) = \frac{(C+E+I-H)}{R(n)} \times \frac{1}{(1-T)}$$

C – the cost of the consumer education program includes the following:

Consumer Education Costs –The incremental cost of programs designed to educate consumers regarding the competitive market such as advertising, customer notices, informational materials cost, and any other incremental cost associated with educating consumers about the market and about available mitigation programs offered by the Company less any cost covered by the Company's Paragraph 37 Funds. Costs associated with this program shall be expensed to FERC account 910. These costs shall also include the costs of providing expanded universal service program education and outreach to low and moderate income customers to recover up to $800,000 per year commencing on January 1, 2025.

MC(n) = consumer education cost per customer for customer class n including over/(under) recovery and associated interest.

E – The estimated over or (under) recovery from the prior year. The reconciliation period shall be the 12 months ended December 31

I – Interest on any over or (under) recovery balance. Interest shall be a rate of 6% and shall be calculated from the month of over or under collection to the mid-point of the recovery period.

H – The value of revenue share commissions received by the Company for the customer class from a home services provider with which the Company has entered into a commercial arrangement for marketing of the home services provider's services to the Company's customers. Commissions will be allocated between the Company's Electric and Gas divisions in proportion to the customer counts in the customer class.

n – Customer class where 1 = residential, 2 = C&I up to 100 kW, 3 = C&I from 100-500 kW, and 4 = C&I >500 kW

R – The total delivery service customers for the customer class for the application period where the application period shall be the 12-month period commencing annually on April 1 after the reconciliation period.

T – The current Pennsylvania gross receipt tax rate included in base rates.

Filing Schedule: The estimated surcharge shall be filed by February 1 of each year to be effective on the following April 1. The application period shall be the 12 months that start the April 1 effective date of the surcharge. The Bureau of Audits shall audit the data in the surcharge on an annual basis.

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TRANSMISSION SERVICE CHARGE (TSC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of all transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's default service load.

Applicability: The surcharge shall be assessed to all default service customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The surcharge shall be calculated on a semi-annual basis using the formula below:

$$TSC(n) = \frac{(C+E+I)}{S(n)} \times \frac{1}{(1-T)}$$

TSC(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

Network Integration Transmission Service costs and Non-Firm Point to Point Transmission costs. Included in the cost to be recovered is a working capital (WC) component as defined below.

Charges assessed by PJM for network service within the PECO zone. Included in such charges are costs for the base network service charge for the zone as well as any load serving entity charges assessed to PECO under the PJM OATT that are listed in PECO's Supply Master Agreement Exhibit D as the responsibility of the Buyer. Included in the cost to be recovered is a working capital (WC) component as defined below.

WC – cost for working capital associated with the purchase of transmission service from PJM at a rate of $311 per mW. WC is a component of the 'C" factor

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E – The estimated over or under recovery from the applicable reconciliation period.

I - interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001. This interest rate basis becomes effective with January 2016 over or under collections.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated default service sales for residential class and the street lighting class in the applicable application period. For the commercial and industrial class it shall be the estimated billed demand for the applicable application period. The application period will be the period when rates will be in effect.

T – The current Pennsylvania gross receipt tax rate included in base rates.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Transmission Service Rate:

R= $.00787 per kilowatt hour (D)
RH= $.00787 per kilowatt hour (D)
Small C&I = $1.57 per billed transmission kW (D)
Large C&I = $1.44 per billed transmission kW (D)
Street Lighting = $.00001 per kilowatt hour (D)¶

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NON-BYPASSABLE TRANSMISSION CHARGE (NBT)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of certain transmission service related costs incurred under the PJM open access transmission tariff on behalf of the Company's distribution service load in accordance with Docket # P-2014-2409362.

Applicability: The surcharge shall be assessed to all distribution customers. The cost shall be allocated to each rate class based upon the coincident peak used by PJM to establish the network service obligation.

Billing Provisions: The NBT shall be included in distribution rates charged to customers taking service under the Residential, Small C&I and Street Lighting class rate schedules as described below.

For Rates PD, HT, and EP (Large C&I class), a PJM Peak Load Contribution (PLC) shall be determined in accordance with PJM rules and used to calculate the NBT. Customer's PLC will be computed to the nearest kilowatt. The NBT shall be recovered through a separate charge listed on customers' bills.

The surcharge shall be calculated on a semi-annual basis using the formula below:

NBT(n) = (C+E+I)/S(n) * 1/(1-T) where;

NBT(n) = transmission service cost for customer class n including over or under recovery and associated interest.

C – the transmission service charges incurred by PECO under the PJM open access transmission tariff. These costs shall include the following:

Regional Transmission Expansion Plan charges, Expansion Cost Recovery charges, Generation Deactivation/Reliability Must Run charges and any costs to implement the Non-Bypassable Transmission charge in accordance with Docket # P-2014-2409362.

E – The estimated over or under recovery from the applicable reconciliation period.

I – Interest on any over or under recovery balance. Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the recovery period.

n – rate class where: 1 = residential, 1a = RH, 2 = small C&I, 3 = large C&I, 4 = street lighting

Residential – Rates R, RH (reconciled as a group)
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP (reconciled as a group)
Street Lighting – SLE, SLC, SLS, POL, AL, TLCL (reconciled as a group)

S – Estimated distribution service sales for residential class and the street lighting class in the applicable application period. For the Small C&I class (Rate GS) it shall be the estimated billed demand for the applicable application period. For the Large C&I class (Rates PD, HT, and EP), the PJM PLC shall be used to calculate the NBT. The application period will be the period when rates will be in effect.

T – The currently effective gross receipts tax rate.

Filings and Reconciliations: The Company shall submit filings 15 days prior to the start of the application period beginning June 1, 2015. Thereafter, the Company will file a surcharge adjustment 15 days prior to June 1 and December 1 of each year. If it is apparent that such methodology would result in a significant over or under recovery before the next 6 month filing for an individual customer class, the Company may propose a rate adjustment 15 days prior to the next effective GSA rate adjustment date (Effective date of March 1, September 1). The annual reconciliation statement will be made by December 31 each year.

Current Non-Bypassable Transmission Rate:

R= $.00408 per kilowatt hour
RH= $.00408 per kilowatt hour
Small C&I = $0.87 per billed distribution kW
Large C&I = $1.08 per kW based on the PJM PLC
Street Lighting = $.00015 per kilowatt hour

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PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS (EEPC)

Purpose: The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's Phase IV Energy Efficiency and Conservation Program Costs (EEPC).

Applicability: The surcharge shall be a calculated for billing purposes for all customers. The EEPC shall be charged to each rate schedule using the following units:

Phase IV

Rates R, RS, RH:	$0.00176/kWh
Rates GS:	$0.00392/kWh
Rate SL-E,	($0.08)/location
Rate SL-C	($0.07)/location
Rate AL:	($0.02)/location
Rate TLCL:	($0.00085)/kWh
Rates HT, PD, EP:	$1.18/kW based on PJM Peak Load Contribution (PLC)

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The Variable Distribution Service charges, for the residential rate schedules shall include the above listed EEPC surcharge. For the municipal lighting rate schedules, the applicable variable or fixed distribution service charges shall include the EEPC surcharge.

For Rate GS, the EEPC shall be recovered through a separate variable distribution charge listed on customer's bills. For Rates PD, HT and EP, a PJM PLC shall be determined in accordance with PJM rules and used to calculate the EEPC. Customer's PLC will be computed to the nearest kilowatt. The EEPC shall be recovered through a separate variable distribution charge listed on customer bills.

Calculation of EEPC Surcharge and the Over/Under Recovery:
Billing Provisions: The surcharge and over/under recovery shall be calculated by rate schedule on an annual basis using the following formulas:

$$EEPC(n) = \frac{(C-E)+(SWE)+(PDR)}{(BU)} \times \frac{(1)}{(1-T)}$$

C – The cost of the Energy Efficiency and Conservation Program includes: all expenditures, of the individual programs such as materials, equipment, installation, custom programs, evaluation measurement/verification, educating customers about availability to the extent not included in Consumer Education cost, not recovered through any separate recovery mechanism, and any other cost associated with implementation of the programs. Costs that relate to measures that are applicable to more than one rate class or that are shown to provide system-wide benefits, will be allocated to each class based on the ratio of class-specific projected program costs to the total projected program costs. The program costs are those approved by the PAPUC and audit costs for the Phase IV program ending May 31, 2026

E - The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

SWE – The cost in dollars of the PaPUC's Statewide Evaluator. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

PDR – The savings/costs from the portion of projected EE Peak Demand Resources (PDR) nominated into PJM's Forward Capacity Market (FCM). The Company will apply any proceeds/deficiencies from nominated PDR to the appropriate customer classes. These costs will be reconciled separately and added to the EEPC and will not be subject to the 2% spending limit of the EE&C Plan.

BU – The total Billing Units for the applicable recovery period.

T – The current Pennsylvania gross receipts tax rate included in base rates.

n - The rate class for which the EEPC is being calculated: 1 = Residential, 2 = Small C&I, 3 = LC&I, 4 = Street lighting
- Residential - Rates R, RH
- Small C&I – Rate GS
- Large C&I – Rates HT, PD, EP
- Street Lighting – Rates SLE, SLC, AL, TLCL

Filings and Reconciliations: The estimated EEPC shall be filed by May 1 each year to be effective through May 31.
The first surcharge, effective June 1, 2021 will contain "C" and "E" factors calculated as follows: The "C–factor" will have two components; one including Phase III costs and the other including Phase IV costs. The Phase IV component will be set using projected costs for the 12 month period from June 1, 2021 through May 31, 2022. The Phase III component will be set using any Phase III costs from projects started prior to the end of Phase III, but not yet billed as of June 1, 2021. For the "E-factor" over/under rate will include the Phase III costs for the 10 month period from June 1, 2020 through March 31, 2021.

The second EEPC, effective June 1, 2022, will be calculated as follows: the "C-factor" will include Phase IV costs for the period June 1, 2022 through May 31, 2023 and the "E-factor" will include costs for 12 months comprising Phase III costs for the 2 months of April and May 2021 and Phase IV costs for the 10 months of June 1, 2021 through March 31, 2022. Subsequent EEPC's, effective June 1 each year will be calculated using a 12 month "C factor" for the period June 1 through May 31 and an "E factor" for the period of April 1 through March 31.

A reconciliation statement filing, in accordance with C.S. Title 66 §1307(e), will be made by April 30 of each year. The last Phase III only reconciliation statement will be for the 10 month period from June 1, 2020 through March 31, 2021. Phase IV reconciliation statements will be for the 12 month period April 1 through March 31 of each plan year. The first Phase IV reconciliation statement will cover the period April 1, 2021 through March 31, 2022 and include 2 months (April and May) of Phase III revenues and expenses and 10 months of Phase IV revenues and expenses (June through March). The EEPC mechanism is subject to annual audit review by the Bureau of Audits.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)

In addition to the net charges provided for in this Tariff, a value of 0.00 % will apply consistent with the Commission Order dated October 22, 2015 at Docket No. P-2015-2471423, approving the DSIC.

1. General Description

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

Poles and Tower (Account 364);
Overhead conductor (Account 365) and underground conduit and conductors (Accounts 366 and 367);
Line transformers (Account 368) and substation equipment (Account 362);
Any fixture or device related to eligible property listed above, including insulators, circuit breakers, fuses, reclosers, grounding wires, crossarms and brackets, relays, capacitors, converters and condensers;
Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective January 1, 2016.

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective January 1, 2016, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in the Company's rates or rate base and will have been placed in service between September 1, 2015 and November 30, 2015. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Billing for the DSIC will be on a bills rendered basis. Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC Eligible Plant Additions Reflected
January 1	September - November
April 1	December - February
July 1	March - May
October 1	June - August

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the Company's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service and the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the Company's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

D. Formula: The formula for calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e) \times 1/(1-T)}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168.

PTRR = Pre-tax return rate applicable to DSIC eligible property.

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax. **[NOTE: UTILITY MAY ELECT TO INCLUDE STFT CALCULATION IN THE PTRR COMPONENT].**

Dep = Depreciation expense related to DSIC-eligible property.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit, as described below.

T= If applicable, Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from applicable customers.

Revenue shall be based on three-month period of projected annual revenues.

[NOTE: THE DSIC CALCULATION DOES NOT FACTOR IN THE PLANT OF ACQUIRED TROUBLED COMPANIES OR THE REVENUE OF CUSTOMERS ACQUIRED FROM TROUBLED COMPANIES UNTIL SUCH PLANT AND CUSTOMER RATES HAVE BEEN PART OF A BASE RATE CASE BY THE ACQUIRING UTILITY].

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

3. Quarterly Updates: Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, Bureau of Audits and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

4. Customer Safeguards

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq*., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq.*) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change or through an explanatory bill insert included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes.

F. Earning Reports: The DSIC will also be reset at zero if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-day's notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.

G. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 4.B. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

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VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER (VSRII RIDER)

Purpose: The purpose of this rider with annual credits or charges is to extend the costs recovery of the Company's annual Vegetation Strategic Reliability Improvement Initiative to improve system reliability from one (1) year to ten (10) years in order to enhance customer affordability.

Applicability: The VSRII Rider shall be calculated to the nearest one-thousandth of a cent for billing purposes for all R and RH customers. For customers on all other rates, it shall be the nearest one cent. The VSRII Rider will become effective April 1, 2027 upon the Pennsylvania Public Utility Commission's approval at Docket No. R-2026-3060859. Subsequent rates will become effective January 1. The VSRII Rider will be based on a ten-year amortization of annual costs to enhance customer affordability. Revenues on the deferred balance of annual cost will include a return and associated taxes. Each year's original deferred revenue will be offset against annual cost.

The VSRII Rider shall be applied to each rate schedule as follows:

Rate R: ($0.00102)/kWh
Rate RH: ($0.00106)/kWh
Rate GS: ($0.15)/billed kW
Rate PD: ($0.29)/billed kW
Rate HT: ($0.08)/billed kW
Rate EP: ($0.14)/billed kW
Rate SL-E: ($0.07)/location
Rate SL-C: ($0.06)/location
Rate TLCL: ($0.04)/location
Rate AL: ($0.02)/location
Rate POL: ($0.40)/lamp
Rate SL-S: ($3.04)/lamp

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The Variable Distribution charges for the above rates shall include the above listed VSRII Rider. For the lighting rate schedules, the applicable location or lamp charges shall include the VSRII Rider.

Calculation of VSRII Rider and the Over/Under Recovery Billing Provisions:

Billing Provisions: The VSRII Rider and over/under recovery shall be calculated by rate schedule using the following formula:

Credits or Charges = (C(n) + RET(n) – DR(n) - E(n)) / BU(n) / (1 - T(n))

C(n) – The cumulative annual VSRII costs to be recovered from customers by rate class for the applicable year based on a ten year amortization of annual VSRII cost.

RET(n) – Revenue requirements for return on the unrecovered deferred revenue from customers and associated taxes based on average balance during the year. For the return calculation, PECO will use the equity return rate for electric utilities contained in the Commission's most recent Quarterly Report on the Earnings of Jurisdictional Utilities. The capitalization structure and the effective cost of debt will be based on the Company's actual capitalization structure and the effective cost of debt during the year.

DR(n) – Original deferred revenue for each annual VSRII costs recovery, prior to application of the ten year amortization.

E(n) – The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

BU(n) – The total estimated annual billing units for the rate class during the projected period when rates will be in effect.

T(n) – Pennsylvania Gross Receipts Tax rate

n – Applicable rate classifications

Filing and Reconciliations: The VSRII Rider will be calculated and reconciled annually for each year of the program. The credits or charges will be calculated to be effective from January 1 to December 31 of the next projected year and filed with the Pennsylvania Public Utility Commission ten (10) days prior to the effective date. The reconciliation will be filed by February 28 for the previous year, January 1 through December 31. The initial nine month rate effective period is April 1, 2027 through December 31, 2027 and will reflect twelve months of costs and credits for the twelve months ended December 31, 2027. The initial reconciliation period will be April 1, 2027 through December 31, 2027. Subsequently, the rate effective period will be January 1 through December 31 each year with annual reconciliation of data from January 1 through December 31 of the previous year. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection for refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery. Such adjustments would be filed on at least 10 days' notice. The VSRII Rider and associated reconciliation will be subject to audit by the Pennsylvania Public Utility Commission's Bureau of Audits.

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ENERGY EFFICIENCY AND CONSERVATION (EE&C) REGULATORY ASSET RIDER

Purpose: The purpose of this rider with annual credits or charges is to extend the recovery the Company's annual expenditures associated with the Company's Energy Efficiency and Conservation (EE&C) from one (1) year to ten (10) years in order to enhance customer affordability.

Applicability: The annual credits or charges shall be calculated for billing purposes for customers. The EE&C credits or charges shall be applied to each rate schedule using the following units:

Rates R, RH: ($0.00227)/kWh
Rates GS: ($0.00358)/kWh
Rate SL-E: ($0.15)/location
Rate SL-C: ($0.13)/location
Rate AL: ($0.05)/location
Rates HT, PD, EP: ($1.07)/kW based on PJM Peak Load Contribution (PLC)

Rates will become effective April 1, 2027 upon the Pennsylvania Public Utility Commission's approval at Docket No. R-2026-3060859. Subsequent rates will become effective January 1. Credits or charges will be based on a ten-year amortization of annual costs to enhance customer affordability. Revenues on the deferred balance will include a return and associated taxes. Each year's original deferred revenue will be offset against annual cost.

The Variable Distribution Service charges, for the residential rate schedules, shall include the above listed EE&C Regulatory Asset Rider. For the municipal lighting rate schedules, the applicable location or lamp charges shall include the EE&C Regulatory Asset Rider.

For Rate GS, the EE&C Regulatory Asset Rider shall be applied through a separate variable distribution credits or charges listed on customer's bills. For Rates PD, HT and EP, a PJM PLC shall be determined in accordance with PJM rules and used to calculate the EE&C Regulatory Asset Rider. Customer's PLC will be computed to the nearest kilowatt. The EE&C Regulatory Asset credits or charges shall be returned or recovered through a separate variable distribution charge listed on customer bills.

Calculation of EE&C Regulatory Asset Rider and the Over/Under Recovery Billing Provisions:

The EE&C Regulatory Asset Rider and over/under recovery shall be calculated by rate schedule on an annual basis using the following formulas:

Credits or Charges = (C(n) + RET(n) – DR(n) - E(n)) / BU(n) / (1 -T(n))

C(n) – The cumulative annual EE&C costs to be recovered from customers by rate class for the applicable year based on a ten year amortization of annual EE&C costs.

RET(n) – Revenue requirements for return on the unrecovered deferred revenue from customers and associated taxes based on average balance during the year. For the return calculation, PECO will use the equity return rate for electric utilities contained in the Commission's most recent Quarterly Report on the Earnings of Jurisdictional Utilities. The capitalization structure and the effective cost of debt will be based on the Company's actual capitalization structure and the effective cost of debt during the year.

DR(n) – Original deferred revenue for each annual EE&C costs recovery, prior to application of the ten year amortization.

E(n) – The over or (under) recovery from the applicable reconciliation period. Interest will not be applied to any over/under collections.

BU(n) – The total estimated annual billing units for the rate class during the projected period when rates will be in effect.

T(n) – Pennsylvania gross receipts tax rate.

n – The rate class for which the EE&C is being calculated: 1 = Residential, 2 = Small C&I, 3 = LC&I, 4 = Street lighting

Residential – Rates R, RH
Small C&I – Rate GS
Large C&I – Rates HT, PD, EP
Street Lighting – Rates SLE, SLC and AL

Filing and Reconciliations: The EE&C Regulatory Asset Rider will be calculated and reconciled annually for each year of the program. The credits or charges will be calculated to be effective from January 1 to December 31 of the next projected year and filed with the Pennsylvania Public Utility Commission ten (10) days prior to effective date. The reconciliation will be filed by February 28 for the previous year, January 1 through December 31. The initial nine month rate effective period is April 1, 2027 through December 31, 2027 and will reflect twelve months of costs and credits for the twelve months ended December 31, 2027. The initial reconciliation period will be April 1, 2027 through December 31, 2027. Subsequently, the rate effective period will be January 1 through December 31 each year with annual reconciliation of data from January 1 through December 31 of the previous year. A final reconciliation statement will be filed within 30 days after completion of the final over/under collection for refund/recovery. The Company may file interim rate adjustments to eliminate any over or under recovery. Such adjustments would be filed on at least 10 days' notice. The EE&C Regulatory Asset Rider and associated reconciliation will be subject to audit by the Pennsylvania Public Utility Commission's Bureau of Audits.

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RATE R RESIDENCE SERVICE

AVAILABILITY.
Single phase service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and is served through the same meter as the dwelling unit; (g) A detached garage, located on the same premises as the customer's dwelling unit, that is utilized solely for the domestic requirements of the dwelling unit's members and requires separate metering service as a result of wiring restrictions or legal requirements.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37 1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $15.05
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.92

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.12610 per kWh

ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

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RATE RH RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single phase service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is provided through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where the heat pump serves as the heating system for the dwelling and all of the supplementary heating required is supplied by non electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered

CURRENT CHARACTERISTICS. Standard single phase secondary service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $15.05
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $2.92

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VARIABLE DISTRIBUTION SERVICE CHARGE:

SUMMER MONTHS. (June through September)
$0.12610 per kWh for all kWh.

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WINTER MONTHS. (October through May)
$0.10123 per kWh for all kWh

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ENERGY SUPPLY CHARGE:
Refer to the Generation Supply Adjustment Procurement Class 1.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

MINIMUM CHARGE. The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

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COMBINED RESIDENTIAL AND COMMERCIAL SERVICE. Where a portion of the service provided is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS. Standard.

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RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   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.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option commencing September 1, 2021.

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RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP.

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Commencing September 1, 2021, for default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, the Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated.

   If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

2. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period. If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

4. Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

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RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS.

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application online to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The link to the online application can be found on the Green Power Connection pages on peco.com.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

Any interconnection application in (a) Conditionally Approved or (b) Engineering Study status will expire in 6 months unless a customer-generator takes steps to (a) satisfy the conditions of the Conditional Approval or (b) pays for and moves forward with the Engineering Study. A customer-generator will be notified of the upcoming interconnection application expiration 45 calendar days ahead of the expiration date. Prior to the expiration of the 6-month period, a customer-generator may request an extension to resolve the outstanding issues surrounding their interconnection application. Upon a showing of good cause, the interconnection application expiration date will be extended up to but no more than 180 calendar days.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

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RATE-GS GENERAL SERVICE

AVAILABILITY.
Service for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

Transformed service from the Company's distribution system where the company installs, owns, and maintains any transforming, switching and other receiving equipment required.

For service configurations that are nominally 120/208 volts, 3 phase, 4 wires – If either the service capacity or the parallel-generating capacity exceeds 750 kVA for transformers located inside the building, the only rate option available to the customer will be Rate HT. If either the service capacity or the parallel-generating capacity exceeds 750 kVA but remains at or below 1,500 kVA for transformers outside the building, the customer may request service at 277/480 volts, 3-phase 4-wires from transformers located outside the building. Otherwise the only rate option available to the customer will be Rate HT.

For service configurations that are nominally 277/480 volts, 3 phase, 4 wires - If either the service capacity or the parallel-generating capacity exceeds either 750 kVA for transformers located inside the building or 1,500 kVA for transformers located outside the building, the only rate option available to the customer will be Rate HT.

CURRENT CHARACTERISTICS.
Standard single-phase or polyphase secondary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE:
$ 27.28 for single-phase service without demand measurement, or
$ 34.78 for single-phase service with demand measurement, or
$ 83.23 for polyphase service.

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VARIABLE DISTRIBUTION SERVICE CHARGE:
$14.49 per kW of billed demand

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($0.0006) per kWh for all kWh

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ENERGY EFFICIENCY CHARGE: $0.00392 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and ¾.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COSTA DJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILTIY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand may be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.
For those customers with demand measurement the billing demand will be determined as follows:
(a) For customers with measured demand or maximum contract demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand, or (ii) 40% of the maximum contract demand.
(b) For customers with demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.

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If a measured demand customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 1.2 kilowatts.

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.

The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge, plus the Variable Distribution Service Charge per KW of minimum billing demand as described above. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus per KW of billing demand. In addition to the above, for customers in Procurement Class ¾ charges will be assessed on PJM's reliability pricing model.

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RATE-GS GENERAL SERVICE (continued)

SPECIAL PROVISION.

In accordance with Section 1511, Title 66 Public Utilities, a volunteer fire company, non-profit rescue squad, non-profit ambulance service or a non-profit senior citizen center meeting the requirements set forth below, may, upon application, elect to have its electric service billed at any of the following rate schedules: Rate R Residential Service or Rate R-H Residential Heating Service, as appropriate for the application. The execution of an electric service contract for a minimum term of one year at the chosen rate will be required of any entity electing service pursuant to the options provided by this provision.

For the purposes of this provision, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

VOLUNTEER FIRE COMPANY. A separately metered service location consisting of a building, sirens, a garage for housing vehicular firefighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.

The customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of firefighting services.

NON PROFIT SENIOR CITIZEN CENTER. A separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided. The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) or the Commonwealth as a non-profit entity and recognized by the Pennsylvania Department of Aging as an operator of a senior citizen center.

NON-PROFIT RESCUE SQUAD. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility recognized by the Pennsylvania Emergency Management Agency (PEMA) or the Pennsylvania Department of Health as a provider of rescue services. The use of electric service at this location shall be to support the activities of the non-profit rescue squad. Any fund raising activities at this service location must be used solely to support the non-profit rescue squad operations.

NON-PROFIT AMBULANCE SERVICE. A separately metered service location consisting of a building, sirens, a garage for housing vehicular rescue equipment; and qualified by the Commonwealth as a non-profit entity; and a facility licensed by the Pennsylvania Department of Health as a provider of ambulance services. The use of electric service at this location shall be to support the activities of the non-profit ambulance service. Any fund raising activities at this service location must be used solely to support the non-profit ambulance service operations.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

PAYMENT TERMS.
Standard.

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RATE-PD PRIMARY DISTRIBUTION POWER

AVAILABILITY.
Untransformed service from the primary supply lines of the Company's distribution system where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the customer was served with standard primary service before the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO Energy may refuse to increase the load supplied to a customer served under this rate when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO Energy may refuse to change that location back to Rate PD when, in PECO Energy's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.
Standard primary service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $297.61

VARIABLE DISTRIBUTION SERVICE CHARGE:
$1.37 per kW of billing demand
($0.0006) per kWh for all kWh

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ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. The 25kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, plus in the case of Procurement Class 3/4 customers, charges assessed under PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE-HT HIGH TENSION POWER

AVAILABILITY.
Untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.
Standard high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $371.68

VARIABLE DISTRIBUTION SERVICE CHARGE:
$9.22 per kW of billing demand
($0.0006) per kWh for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: $0.31 per kW of measured demand.
For customers supplied at 69,000 volts: $2.47 per kW of measured demand.
For customers supplied over 69,000 volts: $2.47 per kW of measured demand.

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Classes 2 and 3/4.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract. The 25 kW minimum shall apply to the Energy Supply Charge and the Transmission Supply Charge.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the charge per kW component of the Variable Distribution Service Charge, and modify less the high voltage discount where applicable plus in the case of Procurement Class 3/4 customers, charges assessed on PJM's reliability pricing model.

TERM OF CONTRACT.
The initial contract term shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE EP ELECTRIC PROPULSION

AVAILABILITY.
This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed service from the Company's standard high tension lines, where the customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is provided for the operation of electrified transit and railroad systems and appurtenances. Rate EP is also available to legacy transformed service that is receiving service pursuant to Rate EP as of January 1, 2020; Rate EP or successor rates shall remain available for such legacy transformed service until at least December 31, 2040.

CURRENT CHARACTERISTICS.
Standard sixty hertz (60 Hz) high tension service.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION SERVICE CHARGE: $1,292.35 per delivery point

VARIABLE DISTRIBUTION SERVICE CHARGE:
$9.27 per kW of billing demand
($0.0006) per kWh for all kWh

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HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For delivery points supplied at 33,000 volts: $0.36 per kW.
For delivery points supplied at 69,000 volts: $2.89 per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts $2.89 per kW for first 100,000 kW of measured demand.

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class ¾.

ENERGY EFFICIENCY CHARGE: $1.18 per kW of Peak Load Contribution

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, the billing demand will not be less than 40% of the maximum demand specified in the contract.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS.
If the load of a customer located at a delivery point becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the customer at that delivery point, upon the written request of the customer, the Company will establish a new delivery point and bill the customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point and provided that such multi-point delivery is not disadvantageous to the Company. Conjunctive billing under this section is available regardless of whether the conjunctively-billed sites take generation service from one or more generation suppliers and/or PECO default service.

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RATE POL PRIVATE OUTDOOR LIGHTING

AVAILABILITY.
To any residential or commercial customer with outdoor lighting of sidewalks, driveways, yards, lots and similar places, outside the scope of service under Rates SL-S and SL-E.

MONTHLY RATE TABLE.
A Standard Lighting Unit shall be a Cobra Head or Floodlight comprised of a bracket, the lead wires, and a luminaire, including lamp, reactor, and control. The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation

MERCURY-VAPOR LAMPS	PRICE PER LIGHTING UNIT DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 4,000 Lumens)	$22.46	$20.08
175 Watts (nominally 8,000 Lumens)	$30.37	$28.11
250 Watts (nominally 12,000 Lumens)	$37.37	$35.35
400 Watts (nominally 20,000 Lumens)	$48.09	$45.42
400 Watts Floodlight (nominally 22,000 Lumens)	$52.07	$49.40

SODIUM-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
70 Watts (nominally 5,800 Lumens)	$30.80	$28.49
250 Watts (nominally 25,000 Lumens)	$48.77	$46.10
400 Watts (nominally 50,000 Lumens)	$53.30	$50.61
400 Watts Floodlight (nominally 50,000 Lumens)	$57.24	$54.57

Service to the above listed Mercury-Vapor Lamps and Sodium-Vapor Lamps is not available as of January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken mercury vapor or sodium vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

METAL HALIDE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
100 Watts (nominally 7,800 Lumens)	$45.68	$44.18
175 Watts (nominally 13,000 Lumens)	$47.91	$45.11
250 Watts (nominally 20,500 Lumens)	$50.65	$47.89
400 Watts (nominally 36,000 Lumens)	$56.37	$53.77
1000 Watts (nominally 110,000 Lumens)	$98.07	$95.52

HIGH PRESSURE SODIUM VAPOR LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
50 Watts (nominally 4,000 Lumens)	$30.61	$28.26
70 Watts (nominally 5,800 Lumens)	$34.66	$32.07
100 Watts (nominally 9,500 Lumens)	$36.58	$33.99
150 Watts (nominally 16,000 Lumens)	$39.90	$37.32
250 Watts (nominally 25,000 Lumens)	$46.72	$44.09
400 Watts (nominally 50,000 Lumens)	$56.46	$53.86
1,000 Watts (nominally 130,000 Lumens)	$64.94	$63.93

LIGHT-EMITTING DIODE LAMPS	DISTRIBUTION (Co.Pole)	(Cust.Pole)
35 Watts (nominally 3,300 Lumens)	$50.18	$47.75
53 Watts (nominally 5,000 Lumens)	$51.42	$49.00
87 Watts (nominally 8,300 Lumens)	$53.08	$50.65
163 Watts (nominally 15,800 Lumens)	$57.73	$55.30
215 Watts (nominally 20,000 Lumens)	$60.52	$58.09

ENERGY SUPPLY CHARGE. Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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RATE POL PRIVATE OUTDOOR LIGHTING (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of lamps and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, all standard service-supply lines, and all Lighting Units. The customer will install, own and maintain all poles on the customer's property and all service extensions on the customer's property from the Company's standard service-supply lines.

Investment by the Company under standard conditions of supply will be limited to that warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge. Any additional investment will be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Monthly Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

(A) Location Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

Customer construction shall meet the Company's standards which are based upon the National Electrical Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work. The customer shall obtain and submit any permits or other authority requisite to the installation and operation of the Lighting Units served hereunder.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Private Outdoor Lighting installation, the Company will charge for removal or replacement of the installations and the associated poles and conductors used exclusively for the street lighting installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

(B) Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting unit shall be for at least three years.

PAYMENT TERMS.
Standard.

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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES

AVAILABILITY.
To any municipal entity for outdoor lighting of streets, highways, bridges, parks and similar places located outside the city and county of Philadelphia, including directional highway signs at locations where other outdoor lighting service is established hereunder, only if all of the distribution facilities and equipment are installed, owned, and maintained by the Company.

ANNUAL RATE TABLE
The prices in the Rate Table apply to all Company-approved installations for (a) federal, state, county and municipal authorities and community associations entering into a contract for lighting service; and (b) building operation developers for lighting, during the development period, of streets that are to be dedicated, where the municipality has approved the lighting and agreed to subsequently assume the charges for it under a standard contract.

The wattage is composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls, and other load components required for its operation.

Incandescent Filament Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
320 Lumens	32	$149.81
600 Lumens	58	$209.95
1,000 Lumens	103	$292.47
2,500 Lumens	202	$401.92
6,000 Lumens	448	$456.46
10,000 Lumens	690	$551.74

Mercury Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
4,000 Lumens	115	$344.25
8,000 Lumens	191	$362.92
12,000 Lumens	275	$386.25
20,000 Lumens	429	$452.72
42,000 Lumens	768	$643.39
59,000 Lumens	1,090	$723.05

Service to the above listed Incandescent Filament Lamps and Mercury-Vapor Lamps is not available after January 1, 2016 to new Customers or existing customers for new or replacement luminaires. The Company will not replace defective or broken incandescent filament or mercury vapor luminaires, including ballasts. In such cases, the customer must take service under one of the current lighting unit options as set forth below.

High Pressure Sodium-Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
5,800 Lumens	94	$341.87
9,500 Lumens	131	$371.45
16,000 Lumens	192	$416.75
25,000 Lumens	294	$472.76
50,000 Lumens	450	$562.33

Light-Emitting Diode Lamps Size of Lamp (Nominal)	Billing Watts	Distribution
3,300 Lumens	35	$602.62
5,000 Lumens	53	$617.60
8300 Lumens	87	$637.43
15,800 Lumens	163	$693.25
20,000 Lumens	215	$726.70

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment, Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT, APPLY TO THIS RATE.

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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES (continued)

TERMS AND CONDITIONS.

1. Service. Lighting service shall be supplied from distribution facilities and equipment installed, owned, and maintained by the Company. Each lighting installation must be separately connected to a Point of Delivery on the Company's secondary distribution system. Lighting service will be operated on an all-night, every-night lighting schedule under which lights are turned on after sunset and off before sunrise with approximately 4,100 operating hours (average monthly burning hours = 341.11 hours). Each lamp shall be controlled by a photoelectric cell which shall operate to energize the lamp during periods of darkness and de-energize it during other periods. The service includes the supply of Lightning Units and their renewal when burned out or broken. Renewal of lamps will be made only during regular daytime working hours after notification by the customer of the necessity.

2. Standard Installations. The Company will install, own, and maintain its distribution facilities and equipment on the public highways to the extent warranted by three times the prospective revenue recovered through the Company's tariffed Variable Distribution Service Charge, with any additional investment to be assumed by the customer.

Title to all lighting installations of a type approved by the Company shall be vested in the Company and all necessary maintenance, repair and replacement of equipment in such installations will be made by the Company.

Standard supply to lighting installations will be from aerial wires, except that, at the option of the Company, in areas where its other electric distribution facilities are underground, supply may be underground.

3. Non-Standard installations. For underground supply furnished at the request of the customer where aerial supply would be normal, or for other than standard installations made at the request of the customer and of a type approved by the Company, the Company will assume the cost up to the amount it would normally have invested and will require the customer to contribute all excess costs.

The Company may offer non-standard Lighting Units and installations in addition to those listed above in the Annual Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract based on the incremental cost over that listed in the Annual Rate Table. Maintenance, repair and replacement of nonstandard equipment shall be at the expense of the customer.

The installation cost of lighting on private property, or for contracts of less than standard term, shall be paid by the customer.

4. Location, Authorization and Protection. The location of lamps to be supplied is to be approved by the properly designated authorized representative of the customer. The customer shall furnish any requisite authority for the erection and maintenance of poles, wires, luminaires and other equipment necessary to operate the lamps at the approved locations.

Lighting Units shall be installed at locations and upon structures approved by the Company and in positions permitting servicing from a ladder truck.

At the expense of the customer, the Company will relocate a lamp to a new location after receiving a written request from the customer.

The customer shall protect the Company from malicious damage to the lighting system.

5. Equipment Removal. If the customer requests that the Company remove or replace any existing Street Lighting installation, the Company will charge for removal or replacement of the installation and the associated poles and conductors used exclusively for the installation. The Company's charge will include the cost of removal or replacement plus the estimated remaining book value of the removed or replaced equipment less salvage.

6. Outage Allowances. Written notice to the Company prior to 4:00 pm of the failure of any light to burn on the previous night shall entitle the customer to a pro rata reduction in the charges under this rate for the hours of failure if such failure continues for a period in excess of 24 hours after the notice is received. Allowances will not be made for outages resulting from the customer's failure to protect the lighting system or from riot, fire, storm, flood, interference by civil or military authorities, or any other cause beyond the Company's control.

7. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each lighting installation shall be for at least three years.

PAYMENT TERMS.
Bills will be rendered monthly. Each month, for the purpose of prorating the price, shall be considered 1/12 of a year.

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RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
To any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder only if all of the Utilization Facilities, as defined in Terms and Conditions in this Base Rate, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $8.26 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE: $0.02693 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.
* The service location charge includes an Energy Efficiency Program Surcharge ($0.08) per location.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit. That connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company.

DETERMINATION OF ENERGY BILLED.
The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 1 Service. The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of the kilowatt hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.
2. Ownership of Utilization Facilities.

a. Service Locations Supplied from Aerial Circuits: customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-E, such sale will include the supporting pole or post.

b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/drivers, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post foundation with 90 degree pipe bend, and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit.
Except as provided in Paragraph 5 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.

c. Service to Group of Utilization Facilities:

AERIAL SUPPLY
When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

UNDERGROUND SUPPLY
When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

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RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES (continued)

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 11.

Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer.

8. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations shall be furnished by the customer to the Company not less than 10 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

9. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

10. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

11. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

12. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

13. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

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RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES

AVAILABILITY.
Any governmental agency for outdoor lighting, provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places, that complies with each of the following conditions:

(A) Installs a Smart Lighting Control Module approved by the Company that has capabilities including but not necessarily limited to:
  a. Measurement of energy usage at the individual Utilization Facility level.
  b. Customer control of the lamp's burning hours.
  c. Data showing failure of the lamp to burn, such as customer notification, that customer can provide to Company upon request.
  d. Ability of customer to dim the lights (LED only).
(B) Provides energy usage to the Company as described below under Data Requirements.
(C) Installs, owns, and maintains all Utilization Facilities, as defined in the Terms and Conditions of this Base Rate. (All facilities and their installation shall be approved by the Company.)

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers.

Customers may take service under the rate beginning on July 1, 2019. The below listed pricing will be revised, as needed, based on applicable surcharge adjustments prior to the SL-C effective service date of July 1, 2019.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $6.99 per Service Location (as defined below)*
VARIABLE DISTRIBUTION CHARGE: $0.05092 per kWh

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2*.
* The service location charge includes an Energy Efficiency Program Surcharge of ($0.07) per location.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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SERVICE LOCATION.
A Service Location is the Point of Delivery on the Company's secondary circuit that connects to one or more Utilization Facilities. A customer may connect multiple Utilization Facilities to a single Service Location in accordance with Paragraph 2c and approval by the Company

DATA REQUIREMENTS.
The customer must notify the Company of its intent to enroll or modify lights under this rate at least 30 days prior to the start of the regularly scheduled billing cycle during which the enrollment or modification will become effective.

The customer must provide the following data to the Company from its Company-approved Smart Lighting Control Module for each light added or modified:
8. Manufacturer-rated wattage
9. Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
10. Dimming percentage/factor

The Company also requires the customer to provide the Global Positioning System (GPS) coordinates for each light.

DETERMINATION OF ENERGY BILLED.
Upon acceptance of the required data, the Company shall modify the energy billed going forward for a period of up to twelve months or at another frequency as required by the Company. The energy use for a month of a Service Location shall be computed to the nearest kilowatt hour as the product of one thousandth of its wattage, adjusted based on the provided dimming percentage/factor, and the provided burning hours during the calendar month.

The Company may, at any time and without prior notice, request that the customer provide updates to the above data or provide actual energy consumption data and burning hours for each light, by calendar month, for up to the past 12 months to verify the continued accuracy of Company billing.

For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, the Company shall modify the energy billed going forward by changing the burning hours used to the standard 4,100 burning hours as defined below under Paragraph 1 Service of Terms and Conditions.

The Company reserves the right to modify the customer's rate to SL-E in the continued absence of required data from the customer.

TERMS AND CONDITIONS.
1. Service. For any regularly scheduled billing cycle in which the customer has not provided acceptable information from its Company-approved Smart Lighting Control Module, lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours (average monthly burning hours = 341.11 hours). Extended lighting service during all daylight hours will be supplied for lamps specified by the customer. If the customer provides information from the Smart Lighting Control Module as described above to justify a different billing usage, the burning hours provided by the customer will be used instead of the standard 4,100 annual operating hours.

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RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

2. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as the brackets, hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, Company-approved Smart Control Modules, conductors, molding and supporting insulators between the luminaires and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location. The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the customer to install thereon the said Utilization Facilities. If the Company sells aerially supplied streetlighting facilities to a government agency in order to qualify for SL-C, such sale will include the supporting pole or post.
   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities defined as brackets or hangers, luminaires, lamps/LED array(s), ballasts/driver, transformers, individual controls, and conductors and shall assume all costs of installing such Utilization Facilities. Customer shall also provide, own, and maintain the supporting pole or post, foundation with 90 degree pipe bend and conduits from the luminaires to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a Service Location designated by the Company on its secondary voltage circuit. Except as provided in Supply Facilities, the Company shall own conduit from the distribution circuit to the 90 degree pipe bend, shall own conductors from its distribution system to the designated Service Location and shall provide sufficient length of conductors for splicing at the designated Service Location or in the post base where sidewalk level access is provided.
   c. Service to Group of Utilization Facilities:

      AERIAL SUPPLY

      When the customer requests service to a group of Utilization Facilities supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the Utilization Facilities. The Company will provide a service, nominally 100 feet, to the customer's first supporting structure. The customer is responsible for installing supply conductors from the first supporting structure to all Utilization Facilities.

      UNDERGROUND SUPPLY

      When groups of Utilization Facilities are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each Utilization Facility from the designated Service Location. If the customer requests an underground supply to a group of Utilization Facilities and the designated Service Location is a secondary terminal pole, the customer will install, own, maintain all cable, including the cable on the pole.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

4. Power Factor. The Utilization Facilities provided by the customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 10.

   Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

6. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated Service Location on the Company's secondary voltage circuit. All work done by the customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations, or any replacement of the Company-approved Smart Control Module, shall be furnished by the customer to the Company not less than 30 days prior to the effective date of such change. The customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

8. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the luminaires of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the customer will bill the Company for this portion of the replaced facilities.

9. Authorization and Protection. The customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

10. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the customer shall be subject to a revenue test. If the costs exceed the estimated revenue recovered through the Company's tariffed Variable Distribution Service Charges for four years, a customer contribution for all excess costs will be required.

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RATE SL-C SMART LIGHTING CONTROL LIGHTING CUSTOMER OWNED FACILITIES (continued)

11. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

12. Customer Responsibility. The customer shall be solely responsible for determining the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

TERM OF CONTRACT.
The initial contract term for each Service Location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

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RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE

AVAILABILITY.
To any municipality using the Company's standard service for (a) electric traffic signal lights installed, owned and maintained by the municipality, and/or (b) unmetered traffic control cameras or other small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the municipality.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically separate from any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account.
To any non-municipal non-residential customer using the Company's standard service for unmetered small constant load electronic devices with a demand of less than 1.2 kW, owned and maintained by the non-municipal customer, which are electrically integrated with any other facilities, whether municipally-owned or non-municipally-owned, that are receiving service from PECO as a separate account, but only if the non-municipal customer meets the conditions of the Special Termination Rights provision of this Rate.

CURRENT CHARACTERISTICS.
Standard single phase secondary service.

RATE TABLE.
SERVICE LOCATION CHARGE: $4.60 PER LOCATION

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VARIABLE DISTRIBUTION SERVICE CHARGE: $0.02396 per kWh (as defined below)*
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of ($0.00085) per kWh

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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SPECIAL RULES AND REGULATIONS.
The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning hours. The customer shall immediately notify the Company whenever any change is made in the equipment or the burning hours or constant load devices, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of the signal equipment to its poles, wires, or fixtures. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

SPECIAL TERMINATION RIGHTS
Some facilities that receive service under Rate TLCL may be electrically configured such that it is not possible to terminate service to the Rate TLCL facility without also terminating service to a facility that is receiving service under a separate account, Rate or Rider. In the event of non-payment of bills for service to such a Rate TLCL facility, PECO will provide a termination notice to the customer. The customer may then, at its discretion, notify PECO that it intends to engage in self-termination by removing its facilities from the PECO system within 30 days. If the customer has not removed its facilities within 30 days, then PECO may, at its sole discretion and upon 72-hour notice, physically remove the customer facility as a means of terminating service to that facility. Taking service under Rate TLCL constitutes full customer permission for PECO to engage in such removals. Notwithstanding any removal of such facilities by either the customer of PECO, the customer shall remain fully obligated to PECO for payment of all charges incurred under Rate TLCL. In addition, the customer shall pay to PECO its full cost of removing the facilities, including direct and indirect labor costs, use of truck or other equipment, fuel costs, and costs of storing the customer equipment, all at PECO's normal rates for such work at such time as it may perform such removals. PECO shall not be liable for damage, if any, to the customer equipment that occurs during removal or storage.

TERM OF CONTRACT.
The initial contract term for each signal light installation and constant load device shall be for at least one year.

PAYMENT TERMS.
Standard.

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RATE BLI BORDERLINE INTERCHANGE SERVICE

AVAILABILITY.
Electric service supplied under reciprocal agreements, to neighboring electric utilities for resale in their adjacent territory at delivery points where the Company in its judgment can provide capacity in excess of the requirements of present and prospective customers in its own territory and for periods fixed by contract and terminable after the expiration of the initial term if capacity is no longer available.

CURRENT CHARACTERISTICS.
Standard primary or secondary service.

MONTHLY RATE TABLE.
For contracts newly entered on or after January 1, 2019, the Company will provide borderline interchange service under the Variable Distribution Service Charge of the appropriate Base Rate, plus an amount equal to 1% per month on the additional investment in facilities required by the Company to deliver and meter the service supplied. The appropriate Base Rate is the rate under which the Customer would be served if located within the Company's franchised service territory.

The Company will not apply this rate to contracts entered prior to January 1, 2019 unless the Company and the customer mutually agree to do so

MEASUREMENT.
The energy delivered may be metered or may be estimated from the purchaser's resales plus an agreed-upon correction to cover transformation and distribution losses.

TERM OF CONTRACT.
The initial contract term shall be for at least five years, and thereafter from year to year until terminated by 60 days' notice from either party, unless the Company and the customer mutually agree to a different term in the contract for service.

PAYMENT TERMS.
Payment of amounts billed shall be made within 15 days from date of bill.

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RATE AL – ALLEY LIGHTING IN CITY OF PHILADELPHIA

APPLICABILITY. To multiple, unmetered lighting service supplied the City of Philadelphia to operate lamps and appurtenances for all night outdoor lighting of alleys and courts that are installed, owned and maintained by the City, which assumes the cost involved in making the connections to the Company's facilities. This rate shall no longer be available to new lighting installations effective January 1, 2011.

LIGHTING DISTRIBUTION SERVICE DEFINED. All night outdoor lighting of alleys and courts by lights installed on poles or supports supplied by the City.

NOTICE TO COMPANY. The City shall give advance notice to the Company of all proposed new installations or of the replacement, removal or reconstruction of existing installations. The City shall advise the Company as to each new installation or change in the equipment or connected load of an existing installation, including any change in burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.
SERVICE LOCATION CHARGE: $2.90 Per Location (as defined below)*
*The service location charge includes an Energy Efficiency Program Surcharge of ($0.02)

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ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, ENERGY EFFICIENCY AND CONSERVATION REGULATORY ASSET RIDER, VEGETATION STRATEGIC RELIABILITY IMPROVEMENT INITIATIVE REGULATORY ASSET RIDER, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE.

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PLAN OF MONTHLY BILLING.
Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION.
The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever. The customer shall be responsible to determine the amount, location and sufficiency of illumination, including conducting all studies of luminosity, lighting location, and traffic.

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APPLICABILITY INDEX OF RIDERS

Introductory Statement

Customers under different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the Base Rate under which they are provided service. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the customer and the Company as the case may require, notwithstanding anything to the contrary contained in the Base Rate to which the rider is applied.

Riders	Page No.	R	RH	RS	GS	PD	HT	POL	SL-S	SL-E	SL-C	EP	BLI	AL
Capacity Reservation Rider	75-79			X	X	X	X					X		
CAP Rider	80	X	X											
Casualty	81			X	X	X	X					X		
Construction	82				X[1]	X	X					X		
Economic Development	83-84				X	X	X							
Electric Vehicle DCFC Pilot Rider (EV-FC)	85-86				X	X	X							
Emergency Energy Conservation	87						X					X		
Investment Return Guarantee	88				X	X	X							
Night Service GS	89				X									
Night Service HT	90						X					X		
Night Service PD	91					X								
Receivership Rider	92				X	X	X	X	X	X	X	X		X
Temporary Service	93	X	X	X	X	X	X							

[1]Available only to Rate GS customers with demands greater than 500kW

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PILOT CAPACITY RESERVATION RIDER (CRR)

PURPOSE.
This Rider sets forth the eligibility, terms and conditions applicable to Customers who operate generation in parallel with the Company distribution system and for whom the Company needs to reserve electric capacity to serve their load when the customer's generation is offline.

This Rider also sets forth the eligibility, terms and conditions applicable to Customers who want to reserve capacity in excess of their present demand from the PECO distribution system for new business growth or expansion.

DEFINITIONS.
Demand and billing demand are defined in tariff sections "Definitions of Terms and Explanation of Abbreviations" and Section 15 of "Rules and Regulations".

(1) Ability to Shed Load – The capability of the customer to reduce or interrupt its total connected load as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(2) Capacity Reservation – The contracted amount of firm electrical distribution capacity, expressed in kW, reserved by the Company solely to meet the capacity requirement for which a customer has contracted under the CRR.

(3) CRR Level –

a. For customers with Parallel Generation, the portion of their Capacity Reservation equal to the contracted percentage of the Generator Nameplate Capacity of their customer-owned Parallel Generation, determined pursuant to the provisions of the section of this Rider titled "Capacity Reservation vs. CRR Level Designation."

b. For customers seeking to reserve capacity for new business growth or expansion, the portion of their Capacity Reservation for which they have contracted under the CRR for that purpose.

(4) "Failure To Shed Load" Penalty – A charge assessed to a customer with a Capacity Reservation, CRR Level, or both that were set in whole or part based upon Ability to Shed Load when that customer's generator goes offline and the customer does not shed load as agreed upon.

(5) Generator Nameplate Capacity **–** The maximum rated output of a generator under specific conditions designated by the manufacturer.

(6) Operational Flexibility in Operation of Generation – The capability of the customer to flexibly operate multiple generating facilities as a means of offsetting some or all of the loss of its Parallel Generation, in the event that its Parallel Generation goes offline or is not operating to full capacity.

(7) Parasitic Load – The power consumed by the equipment supporting the operation of a customer's generation.

(8) Parallel Generation – Non-utility generating facility(s) approved for Parallel Operation.

(9) Parallel Operation – Occurs when a non-utility generating facility(s) interconnected with and operates while connected to PECO's distribution system, where the potential exists for electricity to flow from said generating facility(s) into PECO's electric distribution system.

(10) Uncovered Demand – The difference between the customer's CRR Level and the customer's Capacity Reservation

APPLICABILITY/AVAILABILITY.
Applicable to customers, with customer generating facilities that have generating capacity of 100 kW or greater and are first placed online, or are granted approval for Parallel Operation, after January 1, 2016. This includes but is not limited to Qualifying Facilities or Small Power Producers and cogenerators as defined in the Public Utility Regulatory Policies Act, whose electrical requirements are partially or wholly provided by facilities not owned by the Company and when such facilities operate in parallel with the Company's distribution system. All such customers will be supplied under the provisions of this rider, the customer's applicable Base Rate, and other applicable riders. Customers who wish to reserve available electrical capacity in excess of their present demand for new business growth or expansion may do so under this rider.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

NOTICE BEFORE COMMENCEMENT OF CRR SERVICE.

The customer shall not commence initial operation of any other source of supply in parallel with the Company's distribution lines until written permission is given by the Company for such parallel operation. Before a customer is placed on the CRR, the Company must provide written notice to the customer that includes the Capacity Reservation under the CRR and informs the customer that, upon receiving service under the CRR, capacity beyond this amount may not be available to serve the customer. The Company shall have the right to inspect the customer's installation prior to providing such written permission, and at any reasonable time thereafter in accordance with Tariff Rule 9.3.

CAPACITY RESERVATION VS. CRR LEVEL DESIGNATION.

The maximum firm capacity available to be reserved will be determined by the Company based upon its review of capacity available on its system at the time that a request for Capacity Reservation is made.

In all cases, if the requested electric capacity is not available the customer shall pay all cost to the Company of any construction necessary to meet the customer's Capacity Reservation requirement. To the extent that the requested capacity is needed for new business growth or expansion, the standard revenue test will apply when calculating the cost to be paid by the customer.
The Company must reserve capacity for a customer based upon an amount that the Company and customer agree accurately reflects the maximum demand that the Company must stand ready to serve to that customer.

For customers generating in parallel with the Company's distribution system:

For billing purposes, PECO will set the associated CRR Level as designated below:

For customers who have Generator Nameplate Capacity of greater than 100 kW but less than or equal to 5,000 kW, the CRR Level will be 60% of the Generator Nameplate Capacity.

For customers who have Generator Nameplate Capacity of greater than 5,000 kW but less than or equal to 10,000 kW, the CRR Level will be 50% of the Generator Nameplate Capacity.

Any customer, regardless of size of load or generation, may initiate negotiation as set forth below to designate the CRR at a level other than these levels.

Batteries and other electrical storage shall not be deemed to be generators for purpose of the CRR, and the nameplate capacity of storage or battery equipment shall not be included as, or treated as equivalent to, Parallel Generation for purposes of determining a customer's Capacity Reservation or CRR Level.

For customers who want to reserve capacity for new business growth or expansion, both the Capacity Reservation and the associated CRR Level will be determined by negotiation.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

NEGOTIATIONS FOR OPERATION OF CUSTOMER GENERATION.
If the CRR Level is set through negotiations for customers generating in parallel with the Company's distribution system, the following will apply:

The customer and PECO will meet to discuss customer operations. After such discussions, the customer may designate a CRR level other than as set forth above, based upon one or more of the following factors as defined above:

1. Parasitic Load: This will be subtracted from the customer's Generation Nameplate Capacity prior to determining the CRR Level.

2. Operational Flexibility in Operation of Generation: A customer with multiple generating units may commit to operate its facilities as a means of offsetting some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level

3. Ability to Shed Load: A customer may commit to shed some portion of its total connected load to offset some or all of the loss of its Parallel Generation in a manner that reduces its Capacity Reservation requirement and consequently its CRR Level.

If PECO accepts the customer's designated Capacity Reservation and CRR Level then both amounts shall be set at the customer-designated level.

If PECO does not accept the customer's designated Capacity Reservation and or CRR Level then PECO may file a complaint with the PUC (to be referred to the Office of Mediation). Pending resolution of the complaint the Capacity Reservation and CRR Level shall be set at: as follows (subject to retrospective revision upon completion of the mediation/litigation):

- For customer designations based upon Parasitic Load, Operational Flexibility, or both, the Capacity Reservation and the CRR Level will be set at the customer-designated levels.

,

- For customer designations based in whole or part on Ability to Shed Load, the Capacity Reservation and CRR Level will be set at PECO-designated levels,

PROCEDURES TO CONFIRM MODE OF CUSTOMER GENERATION OPERATION
If a customer's CRR Level is set by negotiation based upon Parasitic Load or Operational Flexibility of Generation, or both, then:

- The customer shall inform PECO in writing if its generation operations differ materially from the mode of operations used to set the CRR Level;
- The customer shall verify to PECO once each calendar year that its generator operations in the prior year did not differ materially from the mode of operations used to set the CRR Level; and
- PECO shall have the right to conduct an audit of customer operations to determine whether generator operations differed materially from the mode of operations used to set the CRR Level.

NOTICE OF OPERATION CONTRARY TO A NEGOTIATED CRR LEVEL AND RESET PROVISION.
If, in its determination, PECO believes that a customer has operated its distributed generation units in a manner contrary to the mode of operations used to set the CRR Level, PECO may issue a written violation notice to the customer.

A customer shall not be deemed to have operated its distributed generation units in a manner contrary to the mode of operation used to set its CRR Level if both of the following are true:

- The customer was required to alter its mode of operations in response to a directive from PECO or because of conditions existing on PECO's distribution system.
- The customer's actual demand does not exceed its Capacity Reservation at any time.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

PECO will rescind a violation notice if, within 30 calendar days of receiving the violation notice, a customer furnishes evidence showing that it operated its distributed generation units consistent with the mode of operations used to set the CRR during the period in question. If PECO is not satisfied that the information provided by the customer demonstrates that operated its distributed generation units consistent with the mode operations used to set the CRR Level, PECO may file a complaint with the Commission and the Commission's determination shall prevail on whether the notice of violation will be deemed to be confirmed. If a customer does not furnish such evidence within 30 calendar days of receiving the violation notice, the violation notice is confirmed.

If a customer receives two confirmed violation notices within a 24-month period; the customer's going-forward CRR for the next 12 months shall be set at levels based upon the actual operations that led to the violation notice. Thereafter, the CRR may be reset to a lower levels only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

PENALTY AND RESET FOR FAILURE TO SHED LOAD.
For customers with a Capacity Reservation CRR Level or both that were set in whole or part based upon Ability to Shed Load, the following penalty and reset provisions shall apply:

- Penalty: If the customer's generator goes offline and the customer does not shed load as agreed upon the customer will be assessed a "Failure to Shed Load" Penalty" calculated by determining the amount of load that the customer agreed to shed, but did not shed, and applying a penalty charge equal to 125% of the full demand charge in the prevailing rate to that amount of load on the first such occurrence, and 150% of the full demand charge in the prevailing rate to that amount of load for the second and subsequent occurrences, for the month in which the load shedding did not occur.

- Reset: The customer's going-forward Capacity Reservation and CRR Level for the next 12 months shall be set at a level based upon the actual operations that occurred during the failure to shed load. Alternatively, the customer can opt to pay PECO for the actual cost of the required upgrades to PECO's distribution facilities to allow the customer to use delivery service at the higher operating level during outages in accordance with PECO's line extension policy (Tariff Rule 7.2). Thereafter, these amounts may be reset to a lower level only upon the customer demonstrating that it has made material changes to its mode of operations to allow it to operate in the then-described manner.

TEMPORARY DISCONNECTION OF CUSTOMER SERVICE.
PECO shall have the right to temporarily disconnect the customer on an emergency basis if, in PECO's opinion, the customer's failure to shed load as agreed creates a risk to PECO's distribution system or service to other customers.

BINDING LEGAL DUTY.
A CRR customer whose CRR Level is set at negotiated level based in whole or part upon the customer's representation that it has an Ability to Shed Load will be deemed to have a binding legal duty to shed such load.

RATE AND BILLING.
Subject to the Minimum Charge Provisions below, the demand charges under the customer's underlying applicable Base Rate of GS, HT, PD, and EP apply to the billing demand determined under the CRR.

Customers will be billed monthly their CRR Level plus actual electric demand and usage except as follow below:

For customers who reserve capacity due only to Parallel Generation, if such customer's actual registered demand is greater than the customer's Uncovered Demand for a given month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to such difference, but in no event will the CRR Level be less than zero.

For customers who reserve capacity for business growth or expansion, if the customer's actual registered demand in a given month includes any portion of the CRR Level contracted for expansion for that month, then, for that month only, the CRR Level used to calculate the customer's bill will be reduced by an amount equal to said portion, but in no event will the CRR Level be less than zero.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

MINIMUM CHARGE.

Subject to the Rate And Billing provisions above the monthly minimum charge under the customer's underlying applicable Base Rate of GS, HT, PD, and EP will be calculated based on the minimum demand determined in accordance with the CRR. .
The monthly minimum demand charge for a customer reserving capacity due only to Parallel Generation will be the greater of:

1. The demand as registered by the customer's meter;
2. An amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand or
3. Any designated contract minimum.

The monthly minimum demand for a customer reserving capacity due only to new business growth or expansion will be an amount equal to the customer's CRR Level, plus 40% of the customer's Uncovered Demand
.
The monthly minimum customer charge will be determined by applying the minimum demand to the applicable demand charge for the Customer's underlying applicable Base Rate.

TERM OF CONTRACT.

The term of a CRR contract shall be three years for all non-negotiated CRR applications. For negotiated CRR Levels, the contract term shall be negotiated. There is no right to automatic renewal of a CRR; upon the expiration of the contract term, the Company will review available capacity on its system and, if such capacity is available, the parties will enter into a new CRR contract using the procedures set forth above.

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CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. Customers will be subject to a $20 monthly bill minimum ($10 for non-heating customers) and will not be eligible to obtain Competitive Electric Supply or participate in budget billing. Commencing September 1, 2021 these customers will not be eligible to select the Time-Of-Use default service option.

Based on the applicable level of income and number of household members, CAP customers will receive a monthly fixed bill or Percentage of Income Payment Plan ("PIPP") based upon that individual household's need. The details of the PIPP calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2018-3005795.

CERTIFICATION/VERIFICATION.
Prior to enrollment in the CAP Rider, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Participate in various energy education and conservation programs offered by PECO if identified as high-usage.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE.
The minimum charge per month will be $10 for Residential customers or $20 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP for the first time will have their pre-program arrearage ("PPA") forgiven if the customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. PECO allows for customers who may have missed PPA "forgiveness" due to late or missed payments to "catch-up" on missed PPA forgiveness; whenever a customer brings their bill current, PECO will forgive any missed forgiveness the customer did not receive during that time. If the customer develops any in-program arrearage while on the CAP Rate–that is, if the customer does not pay the entire outstanding balance – then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

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CASUALTY RIDER

AVAILABILITY/APPLICABILITY.
To service provided during a period when a customer is prevented for a length of time in excess of 48 hours from using all or a substantial part of the amount contracted for by reason of strike, riot, fire, storm, flood, drought, interference by civil or military authorities, or any other cause beyond the customer's control ("Period of Interruption").

NOTICE REQUIRED.
Written request shall be made to the Company for the application of this rider with advice as to the extent of the interruption, its date, cause and probable duration. Written requests must be submitted to the Company within 30 calendar days after the end of the Period of interruption.

RATE IMPACT.
During Periods of Interruption, PECO Energy will not apply guarantees of revenue (power factor adjustment, minimum billing demand, and contract minimum) as contained in the customer's Contract, but will apply the actual registered demand. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

BILLS PRORATED.
Bills supplied shall be prorated, based upon the actual level of operation during the Period of Interruption.

RETURN TO NORMAL USE.
The customer shall use reasonable diligence in resuming the use of service as provided in the Contract.

TERM OF CONTRACT.
The initial contract term shall be extended for a period equal to the Period of Interruption so that the Company shall secure a working term at full connected load equal to the term of the Contract.

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CONSTRUCTION RIDER

AVAILABILITY/APPLICABILITY.
To service provided during or immediately following a major construction or expansion period or during a receding load period, after the expiration of the initial contract term, while a business is in process of dissolution. A major construction or expansion period is defined as a construction or expansion project undertaken by the customer which upon completion will require an upward modification of the customer's contract limits.

RATE IMPACT.
During the expanding load period preceding the operation within the load limits provided in the contract or the receding load period subsequent to the fulfillment of the initial contract term, PECO Energy will not apply the following guarantees of revenue: power factor adjustment, minimum billing demand, and contract minimum. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

RIDER TERM.
The total term of application of this rider during the preliminary or construction period shall be 6 months subject to the option of the Company to grant not more than three successive renewals of the rider term on major construction projects. Its application during a receding load period subsequent to the completion of an initial contract term shall be for not more than one year.

TERM OF CONTRACT.
The initial contract term for service to expanding locations to which this rider is applied shall be extended for a period corresponding to the total number of months this rider is applied to the customer's bill during construction or expansion of the customer's facility.

OTHER RIDERS.
This rider, when applied to service to temporary installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

For customers taking service under PECO's Capacity Reservation Rider (CRR), the terms of the Construction Rider shall only apply to actual demand for load behind the meter that is not covered by the CRR Level, as defined within the terms and conditions of the CRR.

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ECONOMIC DEVELOPMENT RIDER

AVAILABILITY/APPLICABILITY. This rider is available to customers taking distribution service under Rate HT, PD, or GS. For new services, the customer must have a projected load of at least 350 kW and must apply for the rider prior to the service being energized. For existing services, the customer must have a peak load of at least 350 kW and apply for the rider before the load growth occurs. The Company will not begin to apply the rider until at least 30 days after the customer provides to the Company written notice of its desire to be placed on the rider. Customers can qualify for this rider through provisions of either I-A, I-B; or II below. This Rider shall be available to customers regardless of whether the energy is purchased under default service rates or through an EGS.

I EMPLOYMENT & LOAD GROWTH: designed to encourage growth in all sectors of the industrial and commercial group, customers can qualify by meeting the appropriate requirements below.

A. **QUALIFICATIONS**.

1. Manufacturing Customers
   a. The New Manufacturing Customer or existing manufacturing customer files with the Company, before the effective date of the rider for the Service Location, a Manufacturing Sales Tax Exemption Certificate, as defined below, for the Service Location. This condition is waived for Stevedoring Operations located within a Port Enterprise Development Area as defined in Title 12, Chapter 121 of the Pennsylvania Code.
   b. The existing manufacturing customer files with the Company copies of the Base Period Employment Reports as defined below, for the Service Location.
   c. For existing locations has already demonstrated a minimum 10 new jobs and a sustained increase in usage (minimum of 100 kW for at least 3 months) over the Base Period, as defined below. The Company reserves the right to request documentation to demonstrate that employment levels have been maintained over the course of eligibility for this rider.
2. Brownfield Redevelopment
   a. A new or existing customer who develops a site designated as a Brownfield Site (defined below) and demonstrates a minimum of 100 kW of new or incremental load.
3. Large Load Growth
   a. A new or existing customer who adds an additional 100MW or more of new load and adds a minimum of 10 new jobs.
4. Hydrogen Production
   a. A new or existing customer who develops on-site hydrogen production.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment, Federal Tax Adjustment Credit and Nuclear Decommissioning Cost Adjustment.

Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges.

1. Monthly Eligibility – The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.
2. A credit equivalent to 15% of the customer's Variable Distribution Service Charge ("VDC"). For New Manufacturing locations or Brownfield Redevelopment the credit will apply to all kW of the VDC. For all existing customers the credit will apply to all incremental kW of the VDC. For hydrogen producers, the credit will apply to the portion of the customer's billed kW of the VDC associated with their hydrogen production equipment nameplate.

II COMPETITIVE ALTERNATIVE: any manufacturing or non-manufacturing customer with a viable competitive alternative to service from PECO may be eligible for benefits as outlined below.

A. **QUALIFICATIONS**.

1. Provide documentation of a viable, currently available competitive alternative to service from PECO. The customer must provide a written description of the competitive alternative and any further information that the Company requires in order to document the cost and demonstrate the viability of the customer's competitive alternative, and
2. Demonstrate a sustained increase in load (1MW minimum month over month for 3 months) as measured on PECO's meter, or a demonstrated retention of at least 1MW of load and,
3. Demonstrate increasing employment of 10 jobs/MW as reported out on PA Form UC-2, or demonstrated retention of at least 10 jobs/MW of load retained for the same period as #2.

B. **RATE REDUCTION.** The rate reduction will be applicable to the customer's base bill for the Qualifying Service Location before the application of the State Tax Adjustment and Nuclear Decommissioning Cost Adjustment.

1. Any customer will not be eligible for the rate reduction in any month in which the customer has an unpaid balance which includes late payment charges. The Company shall be the sole judge of any customer's eligibility for any rate negotiated rate reduction.
2. Any qualifying existing or new customer may qualify for a negotiated decrease in VDC charges of up to 15% to meet the customer's documented competitive alternative. The rate reduction and payment terms for service may be negotiated and specified in the applicable service agreement. Unless the service agreement provides specific terms governing the billing of charges, Section 17. Billing and Standard Payment Options of the Rules and Regulations of the Tariff shall apply. The Company reserves the right to require updated documentation in order for the customer to remain eligible for the rider.

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ECONOMIC DEVELOPMENT RIDER (continued)

DEFINITIONS.

1. Service Location. A single or contiguous premises having one or more delivery points for distribution service billed by the Company under a single account

2. New Manufacturing Customer. The Company has not previously provided service to the Service Location, or the service previously provided by the Company to the Service Location was not used for substantially the same type of operation or was terminated at least twelve (12) months before the customer's contractually specified effective date for service under this rider. This condition is waived for existing service locations where an entity has assumed operation of a service location from a customer which has ceased operations as a result of dissolution, so long as the formation of the entity did not occur as a result of merger, joint venture, acquisition and/or any other variation of combined business structures with the former customer at the service location. In any event, the completed application for the rider must be made within 6 months from the later of the date: (1) the customer first received service from the Company; or (2) the date the customer received its sales tax exemption certificate from the Commonwealth of Pennsylvania

3. Manufacturing Sales Tax Exemption Certificate. Pennsylvania Sales Tax Blanket Exemption Certificate filed by the customer with the Company showing the address of the Service Location and certifying that more than fifty (50) percent (on an annual basis) of the service purchased by the customer for the Service Location is exempt from sales tax because it is used in manufacturing operations, shipbuilding operations, or ship cleaning operations.

4. Employment Report. The "Employer's Report for Unemployment Compensation" (PA Form UC-2) as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania.

5. Base Period. The twelve (12) month period immediately preceding the billing month in which the customer provides the Company written notice of its desire to be placed on the rider. If the customer does not then qualify for the rider within 60 days of the written notice, then the base period will be the twelve month period immediately preceding the billing period for which this rider is first applied to the customer's bills.

6. Base Period Employment Reports. The Employment Reports for all quarterly reporting periods, as defined by 43 P.S. 753 [d], in the Base Period

7. Base Period Employees. The arithmetic mean of the number of employees each month as reported on the applicable Base Period Employment Report. An adjustment will be made to normalize Base Period Employees in quarters during which either the Casualty or Construction Rider was in effect for the Service Location.

8. Base Period Energy. The number of kilowatt-hours used by the customer for service to the Qualifying Service Location during each month of the Base Period. An adjustment will be made to normalize usage in months during which the Construction or Casualty rider was in effect.

9. Current Employment Report. The Employment Report covering the calendar month immediately following the Base Period as defined by 43 P.S. 753 [d]. The customer may submit an updated Employment Report at any time to reflect increases in Current Period Employees replacing and superseding the original report. The Company reserves the right to request an updated Employment Report at any time which may reflect increases or decreases in Current Period Employees replacing and superseding the original report.

10. Current Period Employees. The arithmetic mean of the number of employees each month as reported on the Current Employment Report.

11. Brownfield Site. Refers to real property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. Requires documentation either by providing a copy of the pertinent sections of the ASTM E1903-97 Phase II Site Assessment documenting the site contamination or by providing a letter from a local, state or federal regulatory agency confirming the site is classified as a Brownfield by that agency.

TERM OF CONTRACT. This rider shall be in effect for either a period of five years provided that the customer maintains qualification for the duration of that time.

RENEWAL. A customer may renew the rider at any time in accordance with the terms and provisions of the rider as it applies to Qualifying Existing Service Locations. For renewal customers, the Base Period Energy for any month of the new Base Period shall not be less than the Base Period Energy of the corresponding month of the customer's previous Base Period. The Term of Contract for the renewal shall begin on the date on which the renewal of the rider is first applied based on the new Base Period.

TRANSFER OF OWNERSHIP. The Company will only apply the rider to the customer's bills for the term of contract. If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

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Effective January 1, 2025

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)
(Effective January 1, 2026 through May 31, 2029)

AVAILABILITY/APPLICABILITY.
Applicable to a service that is dedicated to Electric Vehicle Supply Equipment (EVSE) and includes at least one permanently connected Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to a stand-alone metered DCFC site. The Company may, at its sole discretion, apply this rider to a service that has both DCFC and other forms of EV charging so long as the combined maximum nameplate capacity rating for all DCFCs connected to the service is equal to at least 80% of the combined maximum nameplate capacity rating for all EVSE connected to the service. The Company may, at its sole discretion, apply this rider to a service that has other loads ancillary to EV charging such as signage, lighting, and communication equipment so long as the maximum combined demand of such loads does not exceed one percent of the combined maximum nameplate capacity rating for all EVSE connected to the service.

The pilot extension begins on January 1, 2026 and expires on May 31, 2029.

The owner of the DCFC shall be responsible for all applicable Tariff rates, fees and charges. The Electric Vehicle owner using the DCFC shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

The DCFC is exempt from resale provisions as outlined in Tariff Rule 13.1 and in accordance with the Commission's Policy Statement at Docket No. M-2017-2604382.

DEFINITIONS.
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.

Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.

Direct Current Fast Charger (DCFC) – A high powered EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered high-powered, the DCFC must have a nameplate charging capacity of at least 50 kilowatts per charging port.

INSTALLATION AND ENROLLMENT.
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who may be either the owner or the host of a third-party owned DCFC, shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company.

The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit. The owner of the DCFC is responsible for maintaining a safe operating environment for the device(s). The Company shall not be liable for any damage or injury, including any consequential damage, resulting from the operation of the DCFC.

The Customer may be responsible to submit an application and documentation of the completed DCFC installation to the Company in order to become eligible for the rider.

TRANSFER OF OWNERSHIP
If, during the term of contract, the ownership of the service location changes, the Company may continue to apply the rider to the new owner's bills for the Service Location. If the Company continues to apply the rider in such circumstances, the Company shall apply the rider to the new owner's bills for the Service Location as if the new owner had been on the rider for the Service Location for the same period of time as was the previous owner.

MISCELLANEOUS GENERAL PROVISIONS.
If the owner requests that service to the DCFC be permanently disconnected, the Company reserves the right to charge that owner for the removal of any required facilities and equipment previously required to furnish service to the DCFC. Such payment by the owner shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

Pilot participants will be required to provide data for all DCFCs connected to the PECO system in order to allow PECO to investigate the development of future DCFC rates. This data will include, for each DCFC: the number installed, the number of charging ports, and the nameplate capacity (in kW).

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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)
(Effective July 1, 2019 through December 31, 2025)¶
AVAILABILITY/APPLICABILITY.¶
Applicable to a service that includes at least one permanently connected and publicly available (workplace fleet and public transit) Public Direct Current Fast Charger ("DCFC") served under Rate GS, PD, or HT installed on or after July 1st, 2019. The Company may apply this rider to either a stand-alone metered DCFC or to a DCFC served as part of an existing service. ¶
¶
The pilot began on July 1, 2019 and expires on December 31, 2025.
The pilot will be modified and extended beginning on January 1, 2026 through May 31, 2029 (Docket No. R-2024-3046932).
¶
¶
The owner of the DCFC shall be responsible for all applicable Tariff rates, fees and charges. The Electric Vehicle owner using the DCFC shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle. ¶
¶
The DCFC is exempt from resale provisions as outlined in Tariff Rule 13.1 and in accordance with the Commission's Policy ¶
Statement at Docket No. M-2017-2604382. ¶
¶
DEFINITIONS.¶
Electric Vehicle (EV) – Any vehicle licensed to operate on public roadways that is propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles.¶
¶
Electric Vehicle Supply Equipment (EVSE) – A device which permits the transfer of electric energy (by conductive or inductive means) to a battery or other energy storage device in an EV.¶
¶
Public Direct Current Fast Charger (DCFC) – A high powered, publicly available (including workplace fleet and public transit) EVSE solely dedicated to recharging an EV's battery via the use of direct current, inductive charging, or other EV charging technology with equivalent capabilities. To be considered publicly available, the DCFC must be located along a public roadway corridor, at a public charging location, at a multi-dwelling unit (MDU) residential building at a public transit charging location, or at a workplace for fleet or customer charging.¶
¶
INSTALLATION AND ENROLLMENT.¶
The Company shall provide service based on the DCFC's nameplate capacity rating when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.¶
¶
Electric Vehicle charging stations shall be constructed in accordance with the Company's service installation policies contained ¶
in its Electric Service Requirements Manual ("Blue Book"), a copy of which may be found at www.peco.com. The customer, who¶
may be either the owner or the host of a third-party owned ...

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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)
(Effective January 1, 2026 through May 31, 2029)

RATE IMPACT.
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a variable demand (kW) credit, equal to 30% of the measured demand to the customer's billed distribution demand. For services where the minimum demand would be calculated under the applicable base as 40% of the maximum contract demand, the Company shall instead calculate minimum demand as 30% of the maximum contract demand. Otherwise, the minimum demand shall be 15 kW.

If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

OTHER RIDERS.
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.

When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand.

This rider will not be applied in conjunction with the Economic Development Rider.

TERM OF CONTRACT.
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal.

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PECO Energy Company
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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)¶
(Effective July 1, 2019 through December 31, 2025)¶
¶
¶
RATE IMPACT.¶
All terms and guarantees of the applicable Base Rate are applicable. The Company shall calculate and apply a fixed demand (kW) credit, initially equal to 50% of the combined maximum nameplate capacity rating for all DCFCs connected to the service, to the customer's billed distribution demand. At no time will the billing demand be less than the minimum demand applicable under the provisions of the applicable Base Rate. The Company reserves the right to reduce the demand credit based on a comparison of the customer's peak demands before and after installation of the DCFC.¶
¶
If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.¶
¶
OTHER RIDERS.¶
This rider, when applied to temporary service installations to which the Temporary Service Rider is also applied, shall not operate as a waiver of the requirement that monthly minimum charges be paid for a period of not less than 6 months.¶
¶
When this rider is applied to a service to which the Night Service GS Rider, Night Service HT Rider, or Night Service PD Rider is also applied, the variable demand credit shall apply to the Off-Peak Billing demand. ¶
¶
This rider will not be applied in conjunction with the Economic Development Rider. ¶
¶
TERM OF CONTRACT.¶
The Company shall provide this credit for no more than 36 months from the date of enrollment or until the conclusion date of the pilot, whichever comes first. There is no right to automatic renewal. Extended participation may be possible and could be predicated on future regulatory directives as yet to be determined. ¶
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EMERGENCY ENERGY CONSERVATION RIDER

AVAILABILITY/APPLICABILITY.
This rider is applicable in conjunction with Tariff Rule 12.3 relating to mandatory emergency energy conservation. It provides for modifications to the charges and practices otherwise applicable to certain customers as a result of compliance with or non-compliance with energy conservation curtailment levels as mandated by the appropriate governmental authority under emergency energy conservation conditions resulting from actual or potential shortage of fuel for electric generation. This rider is applicable to individual electric customer accounts served under Rates EP and HT, with a billing demand of 2,000 kilowatts or higher, in a recent twelve-month period prior to the emergency conservation condition. Customers designated by the procedures of Tariff Rule 12.3 and by the Pennsylvania Public Utility Commission, will be exempt from the provisions of this rider.

BASE PERIOD ENERGY USE.
The base energy use for a weekly period shall be determined by the Company for each applicable customer account based upon a consideration of the customer's actual past or current electric consumption and the customer's existing operations.

MANDATORY CURTAILMENT ENERGY USE LEVEL TARGET.
The mandatory curtailment energy use level target for each applicable customer shall be that percentage of base period energy use ordered pursuant to the emergency energy conservation procedures provided by Tariff Rule 12.3 or other percentage as a result of the order of appropriate governmental authority.

COMPLIANCE.
When the energy consumption in any weekly period during the period of mandatory curtailment exceeds the mandatory curtailment energy use level target, the customer will be deemed to be in non-compliance. Customers deemed to be in non-compliance will not receive the billing modifications as set forth in this rider. In the event of continued non-compliance, the Company, upon notice to the Commission, may discontinue service.

BILLING FOR CUSTOMERS IN COMPLIANCE.
During the period of emergency energy conservation condition, billing will be based on special meter readings made to identify the demand established and energy using during the current energy use period. Customers in compliance with conservation orders will be excused from minimum bills and historical or contract demand or ratchet provisions and will be billed instead on the basis of current consumption and demand whenever the normal calculation method would produce a greater bill. If the customer receives Default Service, the terms of this rider shall not apply to the Energy Supply Charge.

These customers will be individually notified of this special billing provision before the implementation of the emergency energy conservation procedure.

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INVESTMENT RETURN GUARANTEE RIDER

AVAILABILITY/APPLICABILITY.
To contracts which require investment in supply facilities greater than warranted by the incremental revenue recovered through the Company's tariffed Variable Distribution Service Charges of the Base Rate under which PECO Energy provides service.

COST OF EXTENSION.
The cost of the extension of supply facilities, including the cost of the service connection, shall be set forth in each agreement for the application of this rider.

MINIMUM GUARANTEE.
The minimum monthly payment shall be the amount set forth in the rider agreement or, in the event of later increases of the customer's load, the minimum of the rate at which service is rendered, whichever minimum obligation is the greater.

CONSTRUCTION ADVANCES.
Where the service desired is of a special character or doubtful permanency, the Company will require payment of a sum equal to the cost of the extension as an advance for construction. A credit of 20% of the net amount of the customer's revenue recovered through the Company's tariffed Variable Distribution Service Charges will be allowed by the Company up to an aggregate refund of 100% of such sum, with the right to retain such portion of the advance as needed to guarantee the payment of subsequent bills.

FULFILLMENT OF CONTRACT TERM.
In the event of the discontinuance for any reason of the distribution of energy before the expiration of the term of the contract with which this rider is applied, the customer shall pay the Company immediately thereon a pro rata share of the cost of the extension for the unexpired portion of the contract term.

OWNERSHIP OF DISTRIBUTION SUPPLY FACILITIES.
The provisions of this rider shall not under any circumstances be considered as conferring upon the customer any title to, or right of property in, the distribution supply facilities.

CONTRACT TERM.
Contract terms in excess of one year may be arranged with the customer to assure the return required by the investment in distribution supply facilities.

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NIGHT SERVICE GS RIDER

(The number of customers served under this rider may be limited by the availability of the required demand meters.)

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours may be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak

Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate GS (with demand measurement), including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.
Night Service billing and metering charge: $27.38

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Charge per kW of Off-Peak billing demand per month: $4.93

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STATE TAX ADJUSTMENT CLAUSE AND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

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NIGHT SERVICE HT RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, transmission and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak

Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rates HT or EP, including all terms and guarantees, are applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand:
$4.10 per month for Rate HT.
$4.38 per month for Rate EP.

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STATE TAX ADJUSTMENT CLAUSE AND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

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NIGHT SERVICE PD RIDER

AVAILABILITY/APPLICABILITY.
To distribution service provided during Off-Peak Hours for demands in excess of those supplied during On-Peak Hours. The demand specified for Off-Peak Hours shall be limited to an amount determined by the Company which shall be dependent upon the capacity of the generation, trademark and distribution facilities available for such supply.

DEFINITION OF PEAK HOURS.
On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Savings Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the On-Peak Hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as On-Peak Hours.

RATE IMPACT.
Rate PD, including all terms and guarantees, is applicable during On-Peak Hours. If the customer receives Default PLR Service, the terms of this rider shall not also apply to the Energy Supply Charge.

MONTHLY RATE TABLE.

Night Service billing and metering charge: $11.45
Charge per kW of Off-Peak billing demand per month: $5.26

Deleted: 4.18

STATE TAX ADJUSTMENT CLAUSEAND DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) APPLY TO THIS RIDER.

DETERMINATION OF OFF-PEAK BILLING DEMAND.
The Off-Peak billing demand shall be the amount by which the greatest demand during Off-Peak Hours, as determined by measurement, exceeds the billing demand for On-Peak Hours, whether the latter is a minimum or an actual demand, except that, when said greatest demand during Off-Peak Hours exceeds the demand specified for Off-Peak Hours, said greatest Off-Peak demand shall be reduced by the amount of the excess in determining the Off-Peak billing demand. The measured power factor used for power factor adjustment in accordance with Rule 15.3 shall be the power factor coincident with the customer's maximum measured demand during On-Peak hours.

OTHER RIDERS.
This rider will not be applied in conjunction with the Temporary Service Rider.

TERM OF CONTRACT.
The initial contract term shall be for at least one year.

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RECEIVERSHIP RIDER

AVAILABILITY/APPLICABILITY.
To service provided to a Receiver-Trustee for the continued operation of a property formerly under contract for its electric service requirements.

AUTHORITY FOR OPERATION.
The Receiver-Trustee shall possess the authority under appointment by Court, through an order duly entered, to operate premises recited in a contract for electric service under which the Company has been providing service.

ACCEPTANCE.
The Receiver-Trustee shall accept and adopt for the continuation of service the contract theretofore in effect, including all of its provisions, and agree to pay the Company for all charges levied during the receivership-trusteeship at the rate specified therein.

BILLING.
The Company reserves the right to render bills on a biweekly basis. To provide for biweekly billing under this rider, the provisions of the applicable rate and rider, if any, will be modified as follows:

(a) Where applicable, all references to monthly or month will be changed to biweekly or biweek.
(b) Where applicable, capacity charges will first be determined from the pricing in the monthly rate table and such sum will then be multiplied by 14/30ths (0.4667) to determine the capacity charges for the billing period.
(c) The energy charges will be determined by using the prices in the monthly rate table; however, the limit of the kilowatt-hours to be billed in each price block will be determined by multiplying the hours' use of billing demand for each price block or the kilowatt-hour limits of a given price block by 0.4667.
(d) The high voltage discount applicable to Rate HT will be determined by using the pricing in the monthly rate table and such sum will then be multiplied by 0.4667 to determine the discount for the billing period.
(e) The minimum charge will be determined on a monthly basis and such sum will then be multiplied by 0.4667 to determine the minimum charge for the billing period.
(f) A discount of 0.4% will be applied to the total bill.
(g) A bill will be rendered biweekly covering the charges for the preceding billing period and such bill shall be paid within fifteen (15) days after receipt thereof.

If the customer receives Default Service, the terms of this rider shall also apply to the Energy Supply Charge.

TERM OF CONTRACT.
The completion of the term of the contract taken over, or as terminated by the discharge of the Receiver-Trustee, or as arranged with the Receiver-Trustee for the continuation of service under the standard terms of this Tariff.

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TEMPORARY SERVICE RIDER

APPLICABILITY.
To the provision of service, including builders construction service, when the Company must install temporary facilities that will be used for a limited period or for a service that is of doubtful permanency.

AVAILABILITY.
Temporary service will be provided only when the Company has available distribution facilities with sufficient capacity, and if the provision of service will not in any way interfere with service to other customers.

INVESTMENT IN DISTRIBUTION FACILITIES.
The cost of the extension and removal of facilities required to furnish the temporary service under the applicable rate shall be paid by the customer, but such payment shall not confer upon, nor entitle the customer to any title to, or right of property in, said facilities and equipment.

MINIMUM TERM.
Application of this rider to Rates R, R-H and GS shall not, for billing purposes, be considered to be for a period of less than one month.

Application of this rider to Rates PD and HT shall require payment of the minimum provisions of the contract for each month of the temporary service period, but in no case shall such period be considered, with respect to the guarantee of the monthly minimum charges, as of less duration than 6 months.

RATE IMPACT.
Billing shall be under the provisions of the applicable base rate and riders.

TERM OF CONTRACT.
Short term arrangements as agreed upon.

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Effective January 1, 2025

PECO Exhibit JAB-3:
Proof of Revenues at Present and Proposed Rates - Residential

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - Residential (R)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	16,177,098	$ 11.25	$ 181,992,353	$ 15.00	$ 242,656,470
3	Second Meter	571,140	$ 2.19	$ 1,250,797	$ 2.92	$ 1,667,729
4						
5	**Total Customer Charge Revenue**			$ 183,243,150		$ 244,324,199
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	11,346,276,993	$ 0.09405	$ 1,067,117,351	$ 0.11739	$ 1,331,949,242
9						
10	CAP Credits - Distribution			$ (117,244,466)		$ (126,777,882)
11	CAP Credits - Non-Distribution			$ (96,287,118)		$ (96,287,118)
12	CAP Shortfall			$ 59,210,529		$ -
13						
14	Distribution System Improvement Charge (DSIC)			$ 35,867,019		$ -
15						
16	**Total Variable Distribution Revenue**			$ 948,663,315		$ 1,108,884,242
17						
18	Regulatory Initiatives			$ 2,966,580		$ 2,966,580
19	Load Reduction			$ (2,127,998)		$ (2,544,048)
20	Annualization			$ 1,791,326		$ 2,141,553
21						
22	**Adjusted Total Distribution Revenue**			$ 1,134,536,373		$ 1,355,772,526

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - Residential Heating (RH)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	2,522,699	$ 11.25	$ 28,380,364	$ 15.00	$ 37,840,485
3						
4	**Total Customer Charge Revenue**			$ 28,380,364		$ 37,840,485
5						
6	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
7	Base Rate, Summer, June-August	557,450,010	$ 0.09405	$ 52,428,173	$ 0.11739	$ 65,439,537
8	Base Rate, Winter, Jan-April and Oct-Dec	1,956,071,815	$ 0.07052	$ 137,942,184	$ 0.09252	$ 180,978,898
9	Blended Rate, May	147,439,230	$ 0.08323	$ 12,270,807	$ 0.10595	$ 15,621,334
10	Blended Rate, September	144,022,203	$ 0.08080	$ 11,637,370	$ 0.10339	$ 14,890,379
11						
12	CAP Credits - Distribution			$ (14,603,647)		$ (15,791,743)
13	CAP Credits - Non-Distribution			$ (11,993,257)		$ (11,993,257)
14	CAP Shortfall			$ (5,124,492)		$ -
15						
16	Distribution System Improvement Charge (DSIC)			$ 6,812,736		$ -
17						
18	**Total Variable Distribution Charge Revenue**			$ 189,369,874		$ 249,145,148
19						
20	Regulatory Initiatives			$ 672,000		$ 672,000
21	Load Reduction			$ (470,443)		$ (620,024)
22	Annualization			$ 1,405,076		$ 1,851,831
23						
24	**Adjusted Total Distribution Revenue**			$ 219,356,871		$ 288,889,440

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - General Service (GS)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Single-Phase - No Demand	371,362	$ 24.47	$ 9,087,228	$ 27.28	$ 10,130,755
3	Single-Phase - With Demand	1,093,036	$ 31.20	$ 34,102,723	$ 34.78	$ 38,015,792
4	Poly-Phase - With Demand	403,457	$ 74.66	$ 30,122,100	$ 83.23	$ 33,579,726
5	GS Night Service Rider	29,520	$ 24.56	$ 725,011	$ 27.38	$ 808,258
6						
7	**Total Customer Charge Revenue**			$ 74,037,062		$ 82,534,531
8						
9	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
10	Base Rate	7,549,351,071	$ (0.0006)	$ (4,529,611)	$ (0.0006)	$ (4,529,611)
11						
12	**Total kWh-Based Variable Distribution Revenue**			$ (4,529,611)		$ (4,529,611)
13						
14	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
15	Base Rate	24,857,621	$ 10.63	$ 264,236,516	$ 13.62	$ 338,630,781
16	GS Night Service Rider	120,039	$ 3.85	$ 462,150	$ 4.93	$ 592,266
17						
18	**Total kW-Based Variable Distribution Revenue**			$ 264,698,666		$ 339,223,047
19						
20	Distribution System Improvement Charge (DSIC)			$ 11,007,888		$ -
21						
22	**Total Variable Distribution Charge Revenue**			$ 271,176,943		$ 334,693,436
23						
24	Regulatory Initiatives			$ (242,636)		$ (242,636)
25	Load Reduction			$ (1,377,093)		$ (1,664,364)
26	Annualization			$ 644,141		$ 778,513
27						
28	**Adjusted Total Distribution Revenue**			$ 344,238,417		$ 416,099,480

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - Primary Distribution (PD)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	4,476	$ 297.61	$ 1,332,102	$ 297.61	$ 1,332,102
3	PD Night Service Rider	1,068	$ 11.45	$ 12,229	$ 11.45	$ 12,229
4						
5	**Total Customer Charge Revenue**			$ 1,344,331		$ 1,344,331
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	288,121,604	$ (0.0006)	$ (172,873)	$ (0.0006)	$ (172,873)
9						
10	**Total kWh-Based Variable Distribution Revenue**			$ (172,873)		$ (172,873)
11						
12	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
13	Base Rate	733,610	$ 11.41	$ 8,370,485	$ 14.37	$ 10,543,172
14	PD Night Service Rider	2,827	$ 4.18	$ 11,816	$ 5.26	$ 14,869
15						
16	**Total kW-Based Variable Distribution Revenue**			$ 8,382,301		$ 10,558,041
17						
18	Distribution System Improvement Charge (DSIC)			$ 322,350		$ -
19						
20	**Total Variable Distribution Charge Revenue**			$ 8,531,778		$ 10,385,168
21						
22	Regulatory Initiatives			$ 32		$ 32
23	Load Reduction			$ (20,932)		$ (24,860)
24	Annualization			$ 3,446		$ 4,093
25						
26	**Adjusted Total Distribution Revenue**			$ 9,858,655		$ 11,708,764

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - High Tension (HT)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charges**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	33,396	$ 371.68	$ 12,412,625	$ 371.68	$ 12,412,625
3	HT Night Service Rider	11,232	$ 11.45	$ 128,606	$ 11.45	$ 128,606
4						
5	**Total Customer Charge Revenue**			$ 12,541,231		$ 12,541,231
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	13,820,126,638	$ (0.0006)	$ (8,292,076)	$ (0.0006)	$ (8,292,076)
9						
10	**Total kWh-Based Variable Distribution Revenue**			$ (8,292,076)		$ (8,292,076)
11						
12	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
13	Base Rate	32,029,579	$ 7.24	$ 231,894,155	$ 9.22	$ 295,472,456
14	HT Night Service Rider	313,519	$ 3.22	$ 1,009,530	$ 4.10	$ 1,285,426
15	Economic Development Rider	1,008,583	$ (1.09)	$ (1,095,322)	$ (1.38)	$ (1,395,625)
16	High Voltage Discount					
17	33kV	8,458,956	$ (0.24)	$ (2,030,149)	$ (0.31)	$ (2,622,276)
18	66kV	214,469	$ (1.94)	$ (416,070)	$ (2.47)	$ (529,738)
19	>69kV	3,265,468	$ (1.94)	$ (6,335,008)	$ (2.47)	$ (8,065,705)
20						
21	**Total kW-Based Variable Distribution Revenue**			$ 223,027,137		$ 284,144,538
22						
23	Distribution System Improvement Charge (DSIC)			$ 7,654,188		$ -
24						
25	**Total Variable Distribution Charge Revenue**			$ 222,389,249		$ 275,852,462
26						
27	Regulatory Initiatives			$ 1,531		$ 1,531
28	Load Reduction			$ (1,004,009)		$ (1,232,492)
29	Annualization			$ 165,297		$ 202,914
30						
31	**Adjusted Total Distribution Revenue**			$ 234,093,299		$ 287,365,646

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - Electric Propulsion (EP)

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer Charge**	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	Base Rate	465	$ 1,292.35	$ 600,943	$ 1,292.35	$ 600,943
3	EP Night Service Rider	60	$ 11.45	$ 687	$ 11.45	$ 687
4						
5	**Total Customer Charge Revenue**			$ 601,630		$ 601,630
6						
7	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	Base Rate	467,014,438	$ (0.0006)	$ (280,209)	$ (0.0006)	$ (280,209)
10						
11	**Total kWh-Based Variable Distribution Revenue**			$ (280,209)		$ (280,209)
12						
13	**kW-Based Variable Distribution Charges**	**kW**	**Rate**	**Revenue**	**Rate**	**Revenue**
14	Base Rate	1,486,115	$ 6.22	$ 9,243,635	$ 9.27	$ 13,776,218
15	EP Night Service Rider	50,316	$ 2.94	$ 147,929	$ 4.38	$ 220,385
16	High Voltage Discount					
17	33kV	16,752	$ (0.24)	$ (4,021)	$ (0.36)	$ (6,031)
18	66kV (for first 10,000 kW of measured demand per month)	-	$ (1.94)	$ -	$ (2.89)	$ -
19	>69kV (for first 100,000 kW of measured demand per month)	189,471	$ (1.94)	$ (367,574)	$ (2.89)	$ (547,572)
20						
21	**Total kW-Based Variable Distribution Revenue**			$ 9,019,969		$ 13,443,000
22						
23	Distribution System Improvement Charge (DSIC)			$ 321,359		$ -
24						
25	**Total Variable Distribution Charge Revenue**			$ 9,061,119		$ 13,162,791
26						
27	Regulatory Initiatives			$ -		$ -
28	Load Reduction			$ -		$ -
29	Annualization			$ -		$ -
30						
31	**Adjusted Total Distribution Revenue**			$ 9,662,749		$ 13,764,421

PECO Energy Company (Electric)
Rate Year Ended December 31, 2027
Proof of Revenue at Present and Proposed Rates - Lighting

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer-Owned Lighting**					
2	**Service Location Charges**	**Locations**	**Rate**	**Revenue**	**Rate**	**Revenue**
3	SL-E	2,137,452	$ 7.65	$ 16,351,508	$ 8.34	$ 17,826,350
4	SL-C	352,812	$ 6.48	$ 2,286,222	$ 7.06	$ 2,490,853
5	TLCL	173,448	$ 4.22	$ 731,951	$ 4.60	$ 797,861
6	AL	192,384	$ 2.68	$ 515,589	$ 2.92	$ 561,761
7						
8	**Total Service Location Charge Revenue**			$ 19,885,270		$ 21,676,825
9						
10	**kWh-Based Variable Distribution Charges**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
11	SL-E	79,827,256	$ 0.02500	$ 1,995,681	$ 0.02678	$ 2,137,907
12	SL-C	2,910,507	$ 0.04739	$ 137,929	$ 0.05077	$ 147,766
13	TLCL	37,241,257	$ 0.02302	$ 857,294	$ 0.02466	$ 918,369
14						
15	**Total kWh-Based Variable Distribution Revenue**			$ 2,990,904		$ 3,204,042
16						
17	**Company-Owned Lighting**					
18	**Component-Based Distribution Charges**			**Revenue**		**Revenue**
19	SL-S			$ 1,413,077		$ 1,513,782
20	POL			$ 3,626,384		$ 3,884,823
21	**Total Component-Based Distribution Revenue**			$ 5,039,461		$ 5,398,605
22						
23	Distribution System Improvement Charge (DSIC)			$ 914,459		$ -
24						
25	**Total Distribution Revenue**			$ 28,830,094		$ 30,279,472
26						
27	Regulatory Initiatives			$ 827		$ 827
28	Load Reduction			$ -		$ -
29	Annualization			$ 6,989		$ 7,340
30						
31	**Adjusted Total Distribution Revenue**			$ 28,837,910		$ 30,287,639

PECO Exhibit JAB-4:
Modified Base Rate Recovery of CAP Revenues in Gas USFC

Modified Base Rate Recovery of CAP Revenues for Electric USFC

C-Factor Period	Estimated CAP Discounts (Shortfall) (1)	Estimated R/RH Sales (a) (kWh) (2)	Estimated Shortfall Recovered in Base Rates (b) (3) = (2) * $0.0128 thru 12/31/2026 (3) = (2) * $0.0164 as of 1/1/2027	Revenue Shortfall o/(u) Base Recovery (4) = (3) - (1)	Estimated Pre-Program Arrearage Forgiveness (5) = N/A thru 12/31/2026 (5) = $17,845,130 / 12	Estimated Pre-Program Arrearage Forgiveness Recovered in Base Rates (c) (6) - N/A thru 12/31/2026 (6) = (5) * 0.0014 as of 1/1/2027	Pre-Program Arrearage Forgiveness o/(u) Base Recovery (7) = N/A thru 12/31/2026 (7) = (6) - (5)	Revenue Shortfall o/(u) Base Recovery (d) (8) = 4 * 0.73 (8) = (4) + (7)
Jan-27					$1,487,094	$2,082	($1,485,012)	
Feb-27					$1,487,094	$2,082	($1,485,012)	
Mar-27					$1,487,094	$2,082	($1,485,012)	
Apr-27					$1,487,094	$2,082	($1,485,012)	
May-27					$1,487,094	$2,082	($1,485,012)	
Jun-27					$1,487,094	$2,082	($1,485,012)	
Jul-27					$1,487,094	$2,082	($1,485,012)	
Aug-27					$1,487,094	$2,082	($1,485,012)	
Sep-27					$1,487,094	$2,082	($1,485,012)	
Oct-27					$1,487,094	$2,082	($1,485,012)	
Nov-27					$1,487,094	$2,082	($1,485,012)	
Dec-27					$1,487,094	$2,082	($1,485,012)	
	$0	-	$0	$0	$17,845,130	$24,983	($17,820,147)	$0

(a) Non-CAP kWh.

(b) Current factor approved per Docket No. R-2024-3043961.
PECO is proposing to update this factor effective January 1, 2027.

Projected FPFTY 2027 CAP Bill Credits:	$208,174,621
Projected Res Non-CAP Sales for FPFTY 2027 (kWh):	12,699,380,582
Resulting Base Rate Recovery per kWh:	$0.0164

(c) PECO is proposing to create and apply a 12-month baseline Pre-Program Arrearage level of $17,845,130 effective January 1, 2027.

Projected FPFTY 2027 Pre-Program Arrearage Forgiveness:	$ 17,845,130
Projected Res Non-CAP Sales for FPFTY 2027 (kWh):	12,699,380,582
Resulting Base Rate Recovery per kWh:	$0.0014

(d) Current offset factor approved per Docket No. R-2024-3043961.
PECO is proposing to update this factor and apply it solely to CAP participation and Pre-Program Arreaage forgiveness above or below approved baselines, effective January 1, 2027.

Modified Base Rate Recovery of CAP Revenues for Electric USFC

E-Factor Period	Total CAP Discounts (Shortfall) (1)	R/RH Sales (b) (kWh) (2)	CAP Revenues Recovered in Base Rates (c) (3) = (2) * $0.0128 thru 12/31/2026 (3) = (2) * $0.0164 as of 1/1/2027	CAP Revenue Recovery o/(u) Actual (4) = (3) - (1)	Number of CAP Participants As Of Month-End (5) = N/A thru 12/31/2026 (5) as of 1/1/2027	CAP Participation Above/Below Baseline (d) (6) = N/A thru 12/31/2026 (6) = (5) - 145,721 as of 1/1/2027	Average CAP Discount per Customer (7) = N/A thru 12/31/2026 (7) = (1) / (5) as of 1/1/2027	Variance in CAP Discounts (8) = N/A thru 12/31/2026 (8) = (6) * (7) as of 1/1/2027	Total Pre-Program Arrearage Forgiven (9) = N/A thru 12/31/2026 (9) as of 1/1/2027	Pre-Program Arrearage Recovered in Base Rates (e) (10) = N/A thru 12/31/2026 (10) = (2) * .0014 as of 1/1/2027	Pre-Program Arrearage Forgiven Above/Below Baseline (e) (11) = N/A thru 12/31/2026 (11) = (10) - (9) as of 1/1/2027	Basis for Offset (12) = N/A thru 12/31/2026 (12) = (8) + (11) as of 1/1/2027	Offset Amount (f) (13) = N/A thru 12/31/2026 (13) = (12) * .0119 as of 1/1/2027	Base Recovery o/(u) Actual @ Offset (g) (14) = (4) * 0.73 thru 12/31/2026 (14) = (4) + (11) - (13)	C-Factor Revenue (15) = (2) * $0.00117	C-Factor Over/(Under) Recovery (16) = (14) + (15)
Jan-27																
Feb-27																
Mar-27																
Apr-27																
May-27																
Jun-27																
Jul-27																
Aug-27																
Sep-27																
Oct-27 (a)																
Nov-27 (a)																
Dec-27 (a)																
	$0	-	$0	$0					$0	$0	$0	$0		$0	$0	$0	$0

(a) Estimated.
(b) Residential Non-CAP Sales.
(c) Current factor approved per Docket No. R-2024-3043961.
PECO is proposing to update this factor effective January 1, 2027.
Projected FPFTY 2027 CAP Bill Credits: $208,174,621
Projected Res Non-CAP Sales for FPFTY 2027 (kWh): 12,699,380,582
Resulting Base Rate Recovery per kWh: $0.0164
(d) PECO is proposing to create and apply a baseline CAP participation level of 145,721 customers effective January 1, 2027.
(e) PECO is proposing to create and apply a new base rate recovery factor for Pre-Program Arrearage Forgiveness effective January 1, 2027.
Projected FPFTY 2027 Pre-Program Arrearage Forgiveness: $17,845,130
Projected Res Non-CAP Sales for FPFTY 2027 (kWh): 12,699,380,582
Resulting Base Rate Recovery per kWh: $0.0014
(f) PECO is proposing to create and apply a 12-month baseline Pre-Program Arrearage level of $17,845,130 effective January 1, 2027.
(g) Current factor approved per Docket No. R-2024-3043961.
PECO is proposing to update this factor and apply it solely to CAP participation and Pre-Program Arreaage forgiveness above or below approved baselines, effective January 1, 2027.

PECO Exhibit JAB-5:
Calculation of CAP Cash Working Capital Offset Factor

Calculation of CAP Cash Working Capital Offset Factor

	Step 1		**Months**				
1	Bills Behind	**Totals**	**1**	**2**	**3**	**4**	
2	Age of Arrears at Charge-off		190	160	130	100	
3	Percentage of Arrears Billed in the Month	100%	25%	25%	25%	25%	
4	Proportionate Lag Day Contribution (days)	146	48	40	33	25	
	Step 2						
	Arrears (Example)	*$ 1,000*					
1	Incremental Age (number of days from billing date to due date)	22					
2	Age of Arrears at Charge-off	146					
3	Days remaining until Charge off (age of arrears miuns incremental age	124					
4	Dollar Lag Days (days remaining * dollars of arrears)	$ 124,000					
5	Annualized Weighted Return	8.08%	PECO Exhibit MJT-1, Schedule B-7, Line 6, Column 4				
6	Gross Up Factor for Taxes	36.10%	PECO Exhibit MJT-1, Schedule D-19, Line 50, Column 2				
7	Weighted Return (annualized return * gross up for taxes)	11.0%					
8	Days per Year	365.25					
9	Daily Return (weighted return / days per year)	0.0301%					
10	Annualizing Factor	1					
11	Annualized Working Capital per $1,000 Receivables	$ 37.33					
12	Working Capital per $1 Receivables	$ 0.037332					
13	PECO CAP Rate Working Capital Offset	3.7%					

PECO Statement No. 10:
Direct Testimony of Megan A. McDevitt

PECO ENERGY COMPANY
STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: MEGAN A. MCDEVITT

SUBJECT: PROPOSED SECTION 1307 SURCHARGE MECHANISMS AND PROPOSED CHANGES TO PECO ENERGY COMPANY'S ELECTRIC DIVISION TARIFF

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
MEGAN A. MCDEVITT

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Megan A. McDevitt. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Manager, Strategic Initiatives. In that capacity, I am responsible for guiding high priority initiatives and projects across Governmental, Regulatory, and External Affairs as well as across PECO. This includes developing strategies related to economic development, energy security, rate case execution and legislative policy.

3. Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Accounting from DeSales University in 2001. In 2006, I became a Certified Public Accountant in Pennsylvania. In March of 2022, I was promoted to Senior Manager in PECO's Regulatory Policy and Strategy department, following roles of increasing responsibility within Accounting, Finance, Energy Acquisition, and Gas Supply and Transportation since joining PECO in September of 2004. In November of 2025, I began my work as Senior Manager, Strategic Initiatives.

4. Q. What is the purpose of your testimony?

A. My testimony will address proposed changes to PECO's Tariff Electric-Pa. P.U.C. No. 8 ("Tariff No. 8") that have been incorporated in the Company's proposed Tariff Electric-Pa. P.U.C. No. 9 ("Electric Tariff No. 9") filed in this case. My testimony divides the proposed changes into the following categories: (1) terms and definitions; (2) rules and regulations; (3) tariff rates and riders; (4) Section 1307 surcharge mechanisms; and (5) miscellaneous provisions.

5. Q. Are you sponsoring any exhibits in this case?

A. No. However, as explained by Company witness Joseph A. Bisti in PECO Statement No. 9, the various tariff changes that I am identifying and explaining are reflected in blacklining of the relevant pages of the Company's proposed Electric Tariff No. 9 that Mr. Bisti is sponsoring as PECO Exhibit JAB-2. Accordingly, I will refer to PECO Exhibit JAB-2 in certain points in my testimony.

II. PROPOSED CHANGES TO EXISTING TERMS AND DEFINITIONS

6. Q. Please describe the revisions that PECO is proposing to the definition of "Suitable location."

A. PECO proposes to revise the last sentence in the definition of Suitable location to read as follows, "For service at Rate HT, where the customer's demand exceeds 7,000 kW, the customer may be required to provide suitable property on or adjacent to their premises for the installation of the Company's substation and transformation equipment." This change is necessary to account for the growing number of data centers expected to be served at voltages above 33 kV and instances where Company equipment is being installed on customer-provided property.

7. Q. Please describe the revisions that PECO is proposing to the definition of "Standard High Tension."

A. PECO proposes to revise the definition of "Standard High Tension" to increase voltage levels to 500,000 volts to account for the growing number of large data centers expected to be served.

III. RULES AND REGULATIONS

8. Q. Please describe the revisions that PECO is proposing to Rule 3.7 Non-Standard Service and Rule 7.4 Tax Accounting of Contributions-in-Aid-of-Construction ("CIAC") and Customer Advances.

A. PECO proposes to revise Rule 3.7 and Rule 7.4 to clarify tax gross-up rules. PECO proposes to add language to Rule 3.7 Non-standard Service indicating that the cost of installation "includes related income taxes". Additionally, PECO proposes to add language to Rule 7.4 Tax Accounting of CIAC and Customer Advances specifying that Rule 7.4 is applicable to all CIAC or other like payments received "for standard service".

9. Q. Please describe the revisions that PECO is proposing to Rule 7.2 Line Extensions for Standard Service.

A. The speculative load section of Tariff No. 8 provides for two specific types of security, an up-front payment or a surety bond. In Electric Tariff No. 9, PECO is proposing to expand the list of acceptable security to include a cash deposit, letters of credit, or some other form of guarantee, as well as to clarify the up-front payment amount.

10. Q. Please describe the revisions that PECO is proposing to Rule 7.3 Underground Service In New Residential Developments.

A. PECO is proposing to modify Rule 7.3 to allow PECO to obtain security, in the form of a bond or letter of credit, from an applicant for service to a new residential development. PECO will only be able to draw upon such security for reimbursement of distribution and service line installation costs in the event that the developer does not fully develop the planned lots within five years. This modification is intended to protect the Company and other customers in the event that the load for the development does not materialize.

11. Q. Is PECO proposing to revise Rule 18.7, 'Reconnection Charge' to waive certain reconnection fees for eligible confirmed low-income customers?

A. Yes. By way of further response, please refer to the testimony of PECO witness Jacqueline F. Golden in PECO Statement No. 12.

IV. TARIFF RATES AND RIDERS

12. Q. Please describe the revision PECO is proposing to Rate Schedule GS – General Service ("Rate GS").

A. PECO is proposing minor changes to the Determination of Billing Demand section to clarify that, for customers with a contract for a maximum demand greater than 500 kW, the contract minimum demand (defined as 40% of the contract maximum demand) applies regardless of whether the customer's measured demand exceeds 500 kW. This clarification is consistent with the contractual terms currently in place for Rate GS customers with maximum demand greater than 500 kW.

13. Q. Is PECO proposing any changes to the Capacity Reservation Rider ("CRR") in this case?

A. No. The Company is not proposing any changes to its existing CRR. At this time, PECO has no customers with generation operating in parallel with the Company's distribution system being served under the CRR.

V. SECTION 1307 SURCHARGE MECHANISMS

14. Q. What is a Section 1307 surcharge mechanism?

A. Section 1307 of the Public Utility Code, 66 Pa. C.S. § 1307, authorizes utilities to establish automatic adjustment clauses that allow them to recover, outside of a base rate proceeding, specific, designated categories of costs. Cost recovery is subject to annual review and reconciliation, such that over or under-recoveries of actual costs are refunded to customers or recouped, as applicable. The operation of Section 1307 clauses is also subject to annual public hearings and periodic audits by the Pennsylvania Public Utility Commission (the "Commission").

15. Q. Is PECO proposing changes to any of its existing Section 1307 surcharge mechanisms?

A. Yes, the Company is proposing to revise its Distribution System Improvement Charge ("DSIC"), its Consumer Education Plan Costs ("CE"), and its Universal Service Fund Charge ("USFC").

16. Q. Please describe the revision that PECO is proposing to its DSIC in conjunction with this electric distribution rate case.

A. In accordance with the "New Base Rate" section of PECO's DSIC, which was approved by the Commission's Order entered on October 22, 2015 at Docket No. P-2015-2471423, PECO is required to reset the DSIC to 0% upon the effective date of Commission-approved base rates. Accordingly, the DSIC will be set to 0%, effective January 1, 2027, as shown in PECO Exhibit JAB-2.

17. Q. Please describe the revisions that PECO is proposing to its CE in conjunction with this electric distribution rate case.

A. As discussed by Company witness Mr. Brendan Taylor in PECO Statement No. 1, PECO is considering offering a home services program similar to other utilities in Pennsylvania. Under this program PECO would enter into an arrangement for a third-party provider to offer optional maintenance plans and on-demand services designed to help protect customers from the unexpected expense and inconvenience of urgent household issues. Any commissions received by PECO under this arrangement will be credited to customers.

To ensure that customers receive the benefit of revenues generated by the program, PECO proposes to add a new factor, "H" – (Home Services Revenues share commissions), which will be subtracted from "C"– (Consumer Education Costs) within the Billing Provisions calculation. If the value of H exceeds C, the revised calculation could result in a negative surcharge, which would be reflected as a credit to the Customer Charge.

PECO anticipates that the annual home services revenue for customers would be approximately $2 million. The electric CE surcharge is reconciled and updated annually on April 1, and will be adjusted to reflect the new H factor for rates effective April 1, 2027.

18. Q. Please describe the revision that PECO is proposing to its USFC in conjunction with this electric distribution rate case.

A. The USFC, among other things, is a mechanism by which the Company reflects the aggregate bill credits (in dollars) provided to low-income customers through PECO's electric Customer Assistance Program ("CAP") rider each year, that are not included in base rates (the "CAP Shortfall"). In this proceeding, as explained by Company witness Jacqueline F. Golden in PECO Statement No. 12, the Company proposes to increase its annual budget by $500,000 beginning in 2027 to continue to support installation of Health and Safety measures and an annual budget of up to $200,000 to support De Facto Heating program beginning in 2027.

With respect to CAP costs, the current USFC is adjusted so that non-CAP residential customers pay 73% of the total CAP Shortfall amount. The remaining 27% of the CAP Shortfall is absorbed by PECO to account for the estimated impact to PECO's uncollectible expense (22%) and cash working capital requirements (5%) arising from incremental changes to the level of CAP bill credits reflected in base rates. In this proceeding, as explained by Mr. Bisti, the Company proposes to increase the aggregate value of bill credits provided to electric CAP customers included in its base rates and to change the offset factor applied to reconcilable CAP costs in the USFC formula from 27% to 11.9%.

The Company also proposes to include the reconciliation of Pre-Program Arrearages in the E factor calculation effective January 1, 2027.

19. Q. Is PECO proposing any new Section 1307 surcharges in this proceeding?

A. Yes. In this proceeding, PECO proposes two new mechanisms pursuant to Section 1307 of the Public Utility Code, a Vegetation Strategic Reliability Improvement Initiative Regulatory Asset Rider ("VSRII Rider") and an Energy Efficiency and Conservation Regulatory Asset Rider ("EE&C Rider").

20. Q. Please describe PECO's proposed new VSRII Rider.

A. As explained by Company witnesses Brendan Taylor in PECO Statement No. 1 and Jennifer Hanna in PECO Statement No. 2, PECO is proposing a Vegetation Strategic Reliability Improvement Initiative (the "Initiative"). The Initiative is a one-time, eight-year program designed to establish a new foundation for vegetation management in targeted areas of PECO's service territory where tree growth and other vegetation have historically contributed to a disproportionate number of customer interruptions compared to the rest of the PECO system.

The Initiative is expected to cost approximately $130 million over an eight-year period, or approximately $16 million annually. While the annual costs of the initiative are reflected in base rates based on projected costs for the Fully Projected Future Test Year 2027, PECO is proposing to implement a Section 1307 surcharge mechanism to spread the recovery of those annual costs over a 10-year amortization period. This approach results in a near-term bill reduction for customers during the initial years of the initiative while allowing PECO to recover the full costs of the program over time.

21. Q. Please describe PECO's proposed new EE&C Rider.

A. As explained by Mr. Taylor in PECO Statement No. 1, PECO proposes to implement the EE&C Rider to mitigate the near-term bill impacts associated with the Company's Energy Efficiency & Conservation ("EE&C") programs implemented in compliance with Pennsylvania's Act 129 of 2008, 66 Pa.C.S. § 2806.1 ("Act 129").

Under this proposal, PECO would recover the cost of implementing the Company's EE&C costs from all customers through the existing EE&C sur-charge, while also providing the EE&C Rider to reduce those costs. Each year, the Company would (1) credit customers for the EE&C charge paid by customers, with the credited amount recorded on PECO's books as a regulatory asset, and (2) recover that regulatory asset from customers over a ten-year amortization period, with a carrying charge applied to the unrecovered balance. This process would repeat for each year after the rates in this proceeding become effective.

For example, in 2027, EE&C costs to be recovered are approximately $84 million, including Pennsylvania's Gross Receipts Tax. Under the proposed mechanism, PECO would credit customers the full $84 million to offset the EE&C charge. That credited amount would then be recovered over ten years, resulting in an annual recovery of approximately $12 million in 2027, including a carrying charge calculated annually based on the average unrecovered balance.

As a result, the net cost to customers in 2027 would be approximately $12 million, rather than the full $84 million otherwise recovered under PECO's tariff for EE&C costs, with the remaining balance deferred as a regulatory asset for

recovery in future years. Similar deferrals and amortizations would be recorded for each of the remaining years of PECO's EE&C plans.

PECO seeks approval of the EE&C Rider under the provisions of Section 1330 of the Public Utility Code, which authorizes the Commission to approve alternative rate mechanisms. The Company's responses to each consideration identified in the Commission's adopted Statement of Policy for alternative ratemaking are provided in Exhibit A to PECO Statement No. 1.

VI. MISCELLANEOUS

22. Q. What are the miscellaneous revisions that are being proposed by PECO and reflected in Electric Tariff No. 9?

A. PECO proposes to delete Tariff Page Nos. 85 and 87, which set forth the Electric Vehicle DCFC Pilot Rider ("EV-FC") rules applicable prior to January 1, 2026, as those provisions are no longer relevant.

PECO is also proposing to delete Tariff Page Nos. 35 and 36, which set forth the Incremental COVID-19 Related Uncollectible Expense ("ICUS"), and the Fiber Affiliate Revenue Surcharge ("FARS") which are no longer applicable beginning January 1, 2027, as the remaining over/under recovery balances will be refunded and charged to customers through base rates as explained by Company witness Michael J. Trzaska in PECO Statement No. 4.

VII. CONCLUSION

23. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Megan A. McDevitt, hereby state that I am a Senior Manager, Strategic Initiatives for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 10 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Megan A McDevitt

Dated: March 30, 2026

Megan A. McDevitt

PECO Statement No. 11:
Direct Testimony of Steven J. DeMott

PECO ENERGY COMPANY
STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: STEVEN J. DEMOTT

SUBJECTS: RESIDENTIAL BATTERY ENERGY STORAGE SYSTEM LEASING PILOT PROGRAM

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
STEVEN J. DEMOTT

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Steven J. DeMott. My business address is PECO Energy Company ("PECO" or the "Company"), 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO as Senior Manager of Strategic Planning. In that capacity, I am responsible for managing and directing activities necessary to support executive leadership and business stakeholders with developing strategic business initiatives that will provide value for our customers.

3. Q. Please describe your educational background.

A. I have a Bachelor of Science in Economics from the University of Pennsylvania Wharton School of Business and a Master of Business Administration from the University of Pittsburgh Katz Graduate School of Business.

4. Q. Please describe your professional experience.

A. I began my career with PECO in 1999 as a senior financial analyst. Between 2002 and 2014, I held management roles in several departments in the areas of marketing, revenue management, and eChannels (digital customer service). In July 2014, I was promoted to senior manager of customer projects and system support, where I led a team of professionals in developing analytical and technology strategy for PECO customer operations while providing project management, change management/business integration, and application maintenance support for all

customer service technology platforms. In December 2019, I became Senior Manager of Strategic Planning for PECO and am now responsible for working closely with our organization and stakeholders to lead strategic planning, opportunity assessments, and the development and execution of strategic initiatives that will provide value to our customers.

5. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe PECO's proposal for a Residential Battery Energy Storage System ("BESS") Leasing Pilot (the "BESS Leasing Pilot") to enhance affordability and resiliency for the Company's residential customers.

6. Q. Are you sponsoring any exhibits to accompany your direct testimony?

A. No.

II. BATTERY ENERGY STORAGE SYSTEM LEASING PILOT

7. Q. Please describe PECO's proposed BESS Leasing Pilot.

A. PECO is proposing a pilot program that will offer a discounted lease on a home BESS for up to 200 residential customers who previously installed rooftop solar systems without an energy storage component. Eligible customers may lease a BESS owned by PECO for 10 years for a one-time upfront payment equal to 70% of the installed cost of the battery. The Company will purchase the BESS, which will be installed at the participating customer's home by a manufacturer-certified contractor. The Company will monitor charge and discharge data from the BESS and will use the BESS to reduce demand during peak periods. Participating customers will be able to use the BESS to reduce their electric bills by shifting energy use to off-peak hours to take

advantage of time-of-use ("TOU") rates and to discharge stored energy as backup power during outages.

8. Q. Why is PECO proposing the BESS Leasing Pilot?

A. Resource adequacy challenges during times of peak load can affect reliability and affordability of electric service for all customers. Residential BESSs, if used for peak shaving or everyday load shifting, can help mitigate these challenges. However, only about 5% of PECO's residential solar customers have chosen to install a BESS, and only a small subset of those customers are enrolled in the Company's TOU generation rates,[1] which can make utilization of BESS for load shifting economically beneficial to the customer. The BESS Leasing Pilot will help PECO identify approaches to increase both BESS penetration and utilization of BESS for daily load shifting and/or peak shaving.

9. Q. What are the learning objectives of the BESS Leasing Pilot?

A. Through the pilot program, the Company aims to understand (1) whether and how it can best engage residential customers with installed solar systems and batteries to shift daily peak load to non-peak times, (2) customer behaviors with respect to self-scheduled TOU arbitrage[2] and utility-scheduled load shifts, (3) the potential for a BESS leasing offering to encourage adoption of a BESS by residential customers who have already installed a solar system, and (4) what operating procedures are needed to

[1] PECO does not have visibility into electric generation supplier ("EGS") portfolios or the products and services they offer to residential customers, including time-varying rates. However, as of the date of this filing, no EGS is currently offering TOU rates on papowerswitch.com in PECO's service area.

[2] TOU arbitrage is an energy management strategy that reduces electricity costs by charging BESSs when energy prices are low (off-peak) and discharging the battery when prices are high (peak).

effectively use BESS as a non-wires solution for peak shaving. The Company may also identify additional learning objectives as the BESS Leasing Pilot progresses.

10. Q. Why is the Company interested in using BESSs to shift load?

A. Presently, residential solar installations do little to address resource adequacy because solar output does not align with peak load periods. In the summer, solar output generally peaks from 11 a.m. to 3 p.m., whereas summer system peak loads generally occur from 4 p.m. to 6 p.m. Winter system peak loads typically occur during pre-dawn and post-sunset hours when solar systems do not produce electricity.

11. Q. How does a BESS help with load shifting?

A. When solar systems are paired with a BESS, the battery can be used to offset the home's load during system peak hours and recharge from the solar panels during the day or from the grid during off-peak overnight hours.

12. Q. What data and insights on load shifting does the Company expect to gather through the BESS Leasing Pilot?

A. The BESS pilot will allow PECO to gain insights about the potential for small-scale battery storage to reduce peak power loads by gathering data including, but not limited to:

- Customer battery usage behavior across testing groups with daily load-shifting configurations and event-based cycles, including propensity to override PECO-scheduled charge/discharge cycles.
- The percentage of customers that respond to TOU price signals and/or comply with controlled dispatch and charge periods.
- Projected and actual bill savings for customers who enroll in TOU generation rates.

- The effectiveness of PECO operational procedures for battery control.
- The actual battery coincidence rate for potential future Total Resource Cost calculations.
- Programmatic operations and vendor partnership expectations, and how customers use BESSs (i.e., backup power versus load shifting).
- The efficacy of and customer experience with original equipment manufacturer ("OEM") battery storm mode, which is intended to automatically prevent economic discharge of batteries in advance of weather that has potential to cause power outages.

These learnings will help shape the design of future energy storage offerings for PECO's customers.

13. Q. How will PECO select the manufacturer and installer of the equipment to be used in the program?

A. PECO intends to issue a request for proposals in the second half of 2026 to select both the specific equipment to be used in the program and one or more installers of that equipment. Should the Pennsylvania Public Utility Commission ("Commission") approve the pilot, the Company will be positioned to execute a contract in late 2026 or early 2027 in support of a marketing launch in mid-2027. Given the small scale of the proposed pilot, the Company believes that it can be executed most effectively using equipment from a single OEM.

14. Q. How will PECO manage monitoring and control of the participating batteries, and how will that approach interact with customer control?

A. By utilizing equipment from a single OEM, PECO will be able to utilize that OEM's interface application to both program charge/discharge cycles and gather data on the utilization of the BESS. To enable this, customers must agree to provide a Wi-Fi connection to the BESS and permit PECO access for monitoring and control to be eligible for participation in the BESS Leasing Pilot. Participating customers will retain the ability to set their own battery cycling schedule, including the ability to override daily schedules set by PECO. PECO intends to test various approaches to battery control by dividing participants into test groups receiving different treatments and by adjusting those treatments over time. The Company will reserve the right to schedule mandatory peak-hour discharge events that participants cannot override.

15. Q. How often will PECO cycle the BESS for mandatory peak events?

A. PECO does not intend to set a firm threshold or frequency for mandatory peak events. The Company intends to assess the efficacy of voluntary participation in TOU rates and daily load shifting for mitigation of super peak events, e.g., hours with a high potential to become PJM 5 Critical Peak ("5CP") hours for that year, and use that information to inform PECO's approach to mandatory events. The Company also intends to study the efficacy of various event triggers for attaining load shift away from actual distribution system peak and PJM 5CP hours. Additionally, the Company may adjust its approach to mandatory events based on observations of the impact of mandatory event frequency on customers' voluntary participation in daily cycling, ongoing participation in the program, and satisfaction with the program.

16. Q. Will the Company encourage participants to enroll in TOU rates?

A. Yes, the Company will encourage participants to enroll in a TOU rate either from PECO or from an EGS. BESSs and TOU rates work together to save customers money by charging batteries when electricity prices are lower (off-peak) and using the stored energy during expensive peak hours. PECO estimates that at 2025 electric rates, a typical participating customer would save $35 per month on PECO's existing TOU generation rate by charging their BESS during super-off-peak hours and discharging it during on-peak hours to supply the home's usage in excess of its solar output.[3]

17. Q. What will happen to the BESS at the end of the 10-year lease?

A. At the end of the lease, a participating customer will have no further financial obligation to PECO. The customer may elect to continue to host the BESS at no cost for the remaining life of the battery so long as they allow PECO to continue to monitor the BESS and schedule charge and discharge cycles at the Company's sole discretion. Once the BESS has reached end of life, PECO will arrange for its removal and recycling at the Company's cost. Alternatively, the customer may choose to have PECO remove the BESS after 10 years at the Company's expense, in which case the Company will seek opportunities to liquidate the equipment within the second-life battery market.

18. Q. What will happen if the customer wants to terminate participation before the end of the 10-year lease?

A. The customer may terminate the lease at any time prior to the end of the 10-year term by providing notice to PECO. In the event of a customer early termination, PECO will

[3] The Company's TOU rate structure offers a higher rate during on-peak hours on non-holiday weekday afternoons from 2 p.m. to 6 p.m. relative to PECO's non-time varying default service rate and a reduced rate during two off-peak periods. The TOU rates include a super off-peak pricing period to encourage electric vehicle and battery charging during overnight low-priced hours (12 a.m. to 6 a.m.).

bill an equipment disconnection fee to the customer, and within 30 days of the early termination, the customer will be required to surrender the BESS to PECO or the Company's designated agent. If the customer fails to surrender the BESS, PECO will bill the customer for the difference between the original installed cost to PECO and their pre-paid lease amount plus 8% annual interest on that difference, compounded monthly. In the case of a home sale, the pre-paid lease will be transferable to the new homeowner. Should the new homeowner choose not to assume the lease obligations, then the home sale will be considered a customer early termination of the lease.

19. Q. What will happen if PECO wants to terminate the pilot before the end of the 10-year lease?

A. PECO will include in the lease agreement an option for early termination of the lease by the Company. Should the Company choose to terminate a lease early, PECO will pay for removal of the BESS and, upon removal, will refund a pro rata share of the prepaid lease amount to the customer. If the customer fails to surrender the BESS within 30 days, PECO will instead bill the customer for the difference between the original installed cost to PECO and their pre-paid lease amount plus 8% annual interest on that difference, compounded monthly.

20. Q. How much will the BESS Leasing Pilot cost?

A. The Company estimates that the average installed cost of each BESS will be $15,000, or $3 million for all 200 systems that have a useful life of 15 years. The Company expects to collect $2.1 million in pre-paid lease payments. The Company also expects to spend approximately $50,000 for customer acquisition, approximately $50,000 for initial configuration of the vendor's portal, and approximately $10,000 in annual

operations and maintenance ("O&M") costs for the vendor's portal. Table 1 shows the net impact of the BESS Leasing Pilot on the fully projected future test year revenue requirement.

Table 1. BESS Leasing Program Impact on 2027 Revenue Requirement

	[$ thousands]
Contribution to Rate Base	
Gross Plant in Service	3,000
Accumulated Depreciation	200
Lease Prepayment Balance	1,890
Net Contribution to Rate Base	910
Impact on Revenue Requirement	
Lease Revenue Amortization	210
(-) Return on Capital	93
(-) Annual Depreciation Expense	200
(-) O&M Expense	110
Revenue Requirement to be Socialized	(193)

Company witness Michael J. Trzaska discusses the revenue requirement adjustments to recover the estimated $193,000 pilot costs in excess of revenues in PECO Statement No. 4.

21. Q. What are the expected customer benefits from the BESS Leasing Pilot?

A. PECO will use the installed capacity of the batteries in the pilot to reduce demand during peak periods, thereby reducing costs for all customers, including non-participating customers by deferring needs for distribution system expansion and reducing transmission capacity costs. To assess the value of these savings, PECO referred to the "Avoided Cost of Transmission and Distribution Capacity Study"

prepared for the Commission by Demand Side Analytics in July 2024.[4] The Company used the values in Table 12 of that report to estimate that a residential BESS program offered to all residential customers with a solar energy system, i.e., one that is not targeted to constrained feeders and terminals, could generate $1,178 in value per participating customer over the 15-year useful life using the following assumptions:

- On average, each BESS installed in the program will shift 1.95 kW[5] of load from peak hours.
- Since the study only calculated deferral values through 2035, for years after 2035 PECO extrapolated values for each year using the compound annual growth rate ("CAGR") from 2033-2035 in the reported data. The Company chose to use the two-year CAGR because that approach yields a more conservative value of savings than using the CAGR over longer time periods.
- Present value of the future deferral values is calculated using an 8% discount rate.

22. Q. What reporting commitments is the Company proposing for the BESS Leasing Pilot?

A. PECO proposes to file an annual report with the Commission detailing the Company's experiences with the first two years of the BESS Leasing Pilot. The report will be filed in 2028 and 2029, no later than December 31 of each year and will include information through September 30 of the year in which it is filed. At a minimum, the report will include the following:

[4] *See* https://www.puc.pa.gov/pcdocs/1855615.pdf.

[5] The average PECO solar customer has a load of 1.95 kW during the hour starting at 5 p.m.

- A narrative summary of the Company's experiences with and learnings from the BESS Leasing Pilot;
- The number and total kWh capacity of BESS installed, by county and by quarter;
- The installed cost of BESS systems, by quarter;
- Prepaid lease payments collected and lease revenues, by quarter;
- Operating and maintenance expenses, by quarter;
- The percentage of participating customers who are enrolled PECO's TOU generation rate, by quarter;
- An assessment of the average monthly bill savings that participants achieve by using the BESS to arbitrage between on-peak and off-peak pricing;
- The percentage of participating customers who utilize the BESS for daily peak shaving, by quarter;
- Load shift, in kW by hour and day of week, in each quarter;
- The rate at which participating customers override daily peak shaving schedules and event schedules set by PECO;
- The number of customers who withdraw from the BESS Leasing Pilot, by quarter.

III. CONCLUSION

23. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Steven J. DeMott, hereby state that I am a Senior Manager, Strategic Planning for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 11 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.



Dated: March 30, 2026

Steven J. DeMott

PECO Statement No. 12:
Direct Testimony of Jacqueline F. Golden

PECO ENERGY COMPANY
STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2026-3060859

DIRECT TESTIMONY

WITNESS: JACQUELINE F. GOLDEN

SUBJECTS: OVERVIEW OF UNIVERSAL SERVICE PROGRAMS; DE FACTO HEATING AND HEALTH AND SAFETY PROPOSALS; RECENT COMPANY PERFORMANCE UNDER CERTAIN CUSTOMER SERVICE METRICS; RECONNECTION FEE WAIVER PROPOSAL; PAYMENT PROCESSING FEES

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
JACQUELINE F. GOLDEN

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Jacqueline F. Golden. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Director of Customer Financial Operations. In that capacity, I am responsible for Customer Financial Operations (Billing, Payment Processing, Revenue Management, and Universal Services).

3. Q. Please describe your educational background.

A. I have a Bachelor of Science in Business Administration from Drexel University and a Master of Business Administration from La Salle University.

4. Q. Please describe your professional experience.

A. I began my career with PECO in 1981 as a customer service representative. Between 1981 and 2000, I held positions of increasing responsibility in several departments including customer operations, large customer accounts, Gas Supply and Transportation, Energy Acquisition, and Finance. My immediate past position was in Regulatory Policy and Strategy as the Director of Strategy. In September 2022, I became the Director of Customer Financial Operations at PECO.

5. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide (1) an overview of PECO's current universal service assistance programs; (2) a description of PECO's proposal for the Low-Income Usage Reduction Program ("LIURP") De Facto Heating Program; (3) a description of PECO's proposal for the LIURP Health & Safety ("H&S") Program; (4) a description of recent Company performance under certain customer service metrics; (5) a description of PECO's proposal to waive certain reconnection fees for eligible confirmed low-income customers; and (6) information about fulfillment of PECO's 2024 electric rate case settlement commitment regarding payment processing fees.

II. PECO UNIVERSAL SERVICE ASSISTANCE PROGRAMS

6. Q. Please describe the universal service programs that PECO offers or administers to support the Company's low-income customers.

A. PECO offers a portfolio of universal service assistance programs designed to support low-income and vulnerable customers in maintaining affordable electric and natural gas service. These programs include:

- The Customer Assistance Program ("CAP"), which provides discounted energy bills to enrolled customers with an annual household income at or below 150% of the federal poverty level ("FPL") as established by the U.S. Department of Health and Human Services. As of December 31, 2025, approximately 137,000 residential electric customers in PECO's service territory – around 9% of PECO residential electric customers – were participating in CAP. PECO's CAP utilizes a Percentage of Income Payment Plan ("PIPP") structure to provide customers with a fixed maximum monthly

bill equal to an established "energy burden" percentage of the customer's annual income.

- LIURP, which provides energy usage reduction education and, if eligible, remediation measures to decrease the amount of energy used by customers, thereby reducing their bills and increasing affordability. PECO's current annual electric LIURP budget is $7.6 million. In 2025, PECO completed approximately 4,800 electric customer audits, with follow-up measures provided to approximately 4,400 customers. PECO also provided H&S measures, which address unsafe conditions that may be a barrier to providing LIURP services, with an annual H&S budget of $1.5 million. In addition, the Company successfully completed a De Facto Heating Pilot in 2023, for households at or below 200% FPL, which I will describe later in my testimony along with PECO's proposal to integrate the pilot as a permanent LIURP component.
- The Customer Assistance Referral and Evaluation Service ("CARES") team, which provides referral and information services to assist special-needs, low-income customers who have financial hardships.
- The Matching Energy Assistance Fund ("MEAF"), which provides hardship grants of up to $1,250 per account to address arrears for customers at or below 200% of the FPL whose service is in threat of termination or has been terminated for non-payment.

- PECO also supports the Low-Income Home Energy Assistance Program ("LIHEAP"), a federally funded grant program that provides supplemental payments to eligible customers' accounts.

7. Q. What other assistance programs has PECO offered?

A. As described in the testimony of Brendan J. Taylor (PECO Statement No. 1), PECO expanded its affordability strategy in 2025 with the launch of the Customer Relief Fund ("CRF"), a $10 million initiative designed to provide immediate bill assistance to limited- and moderate-income households experiencing rising energy costs.

PECO subsequently launched a low-income CRF with a separate $2.5 million budget in March 2026. Similar to the CRF for limited- and moderate-income households, the low-income CRF is administered in partnership with the United Way of Greater Philadelphia and Southern New Jersey. The low-income CRF was designed to provide additional support for customers who are eligible for traditional low-income assistance programs, including CAP, LIHEAP, and MEAF, to strengthen overall affordability.

Finally, PECO also offers low-income customers no-cost energy assessments and direct installation measures through the Company's Act 129 Energy Efficiency and Conservation Plan.

III. PECO LIURP DE FACTO HEATING PROGRAM

8. Q. Has PECO previously offered a LIURP De Facto Heating Program?

A. Yes. PECO implemented a multi-year De Facto Heating Pilot Program ("Pilot Program"), beginning October 1, 2017, which was approved as part of a settlement in the Company's 2016-2018 Universal Service and Energy Conservation Plan

("USECP").[1] "De Facto" heating refers to those households at or below 200% of FPL with non-heating electric accounts (i.e., Rate R) that use electricity for heat because their non-PECO-fueled primary heating source (e.g., oil or gas) is inoperable. Many of these households then use potentially unsafe and inefficient alternative heating sources. This use subsequently increases the customer's electric bill, which can compound any existing payment challenges. The Pilot Program targeted eligible customers to assess opportunities to install new heating systems and other weatherization measures with tangible energy reduction benefits. The Pilot Program concluded in December 2023 and had a budget of $500,000 in its final year.[2]

9. Q. Was the Pilot Program beneficial for customers?

A. Yes. The Pilot Program served 376 customers, with approximately 70% receiving replacement furnaces or boilers and approximately 30% receiving repairs on defective heating systems. Participants significantly reduced their electric usage and reduced use of dangerous and inefficient space heating mechanisms at their premises. Specifically, participants had an average annual savings of 2,681 kWh, or 19.6%, of their pre-treatment electric usage.

10. Q. Is PECO proposing to make De Facto heating a permanent part of LIURP?

A. Yes. Given the success of the Pilot Program, PECO is proposing to include the De Facto Heating Program as a permanent component of LIURP. The customer

[1] *See* PECO Energy Company Universal Service and Energy Conservation Plan for 2016-2018 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4, Docket No. M-2015-2507139 (Order entered August 11, 2016).

[2] A list of LIURP funding changes related to the Pilot can be found in the LIURP section of PECO's 2019-2028 USECP. *See* Docket No. M-2018-3005795.

eligibility requirements and focus of the program would be the same as the Pilot Program.

PECO proposes a budget of up to $200,000 in 2027. The funds will be used to ramp up the program, including onboarding resources, development of processes and program structure, as well as program implementation. Beginning in 2028, the Program would have an annual budget not to exceed $200,000. Making De Facto program measures a permanent part of LIURP will facilitate much-needed energy reduction and financial support benefits for our most vulnerable customers. Funding will be recovered through PECO's Universal Service Fund Charge ("USFC") as described in the direct testimony of PECO witness Megan A. McDevitt (Statement No. 10).

IV. PECO LIURP HEALTH & SAFETY PROGRAM

11. Q. Please describe PECO's LIURP H&S Program.

A. LIURP includes a subcomponent, the H&S Program, which supports measures or repairs necessary to maintain and protect the physical well-being and comfort of an occupant of a dwelling. The H&S Program addresses unsafe conditions that may be a barrier to providing LIURP services, including roof repair and/or replacement, basement waterproofing, stair repair and/or replacement, knob and tube remediations, service upgrades, and mold and asbestos remediation. In 2025, approximately 40% of customers who received LIURP measures also received H&S support.

12. Q. What change is PECO proposing to its LIURP H&S Program?

A. PECO's annual H&S budget has been $1.5 million since 2022 and has supported an average of 2,400 customers each year for the period 2022-2025. The average

cost to provide these services continues to increase by approximately 3% a year, while the H&S budget remains fixed. These increased costs have impacted the number of customers receiving H&S support and the type of measures provided under the fixed budget. In recognition of the influence these average cost increases have had on the H&S program, PECO is proposing to increase its budget by $500,000 beginning in 2027, resulting in an annual budget of $2 million. This additional funding will help to offset the increased costs of providing these services and will continue to support the installation of H&S measures. Funding will be recovered through PECO's USFC as described in the direct testimony of PECO witness McDevitt.

V. RECENT COMPANY PERFORMANCE UNDER CERTAIN CUSTOMER SERVICE METRICS

13. Q. Does PECO use metrics to quantify customer performance?

A. Yes. PECO measures customer service performance using a number of metrics, including Average Speed of Answer ("ASA"), which measures the average number of seconds it takes to reach a customer service representative ("CSR"), and Abandon Rate, which measures the percentage of customers that disconnect the call before reaching a CSR.

14. Q. As of July 2025, did PECO meet its internal goals for ASA and Abandon Rate?

A. No. As of July 2025, PECO's ASA was an average of 216 seconds compared to an internal goal of 18 seconds, while the Abandon Rate was 11.2% compared to the Company goal of 1.6%.

15. Q. Please explain why PECO did not meet its internal goals for ASA and Abandon Rate.

A. In 2024, PECO implemented a new customer information system ("CIS"). The new CIS replaced a dated system that required navigating through multiple menus and screens to locate certain information. The new CIS is modern and simpler, making it easier for CSRs to navigate during customer calls and focus on active listening while efficiently collecting customer data and reviewing customer records to address customer concerns.

In 2025, PECO experienced an increase in call volumes and average handling times as both customers and CSRs adjusted to the new CIS. A portion of the increase in call volumes was related to billing inquiries about high bills, higher usage, and delayed bills. Calls of this nature can extend customer interactions. Additional time was needed by CSRs to address customer issues as the CSRs navigated the new CIS system, resulting in increased call times and impacting ASA and Abandon Rate performance metrics.

16. Q. What measures has PECO implemented to improve these customer service performance metrics?

A. PECO implemented a series of operational, process, and technology measures to improve CSR performance, including:

- PECO conducted call observations to better understand call drivers, identify coaching opportunities, and ensure consistent quality and adherence to standards to continuously improve the experience of our customers. Call observations helped identify specific behaviors and process gaps that, once

addressed, contributed to improved metrics for ASA and Abandon Rate.

- PECO implemented a new process flow tool called ProcedureFlow, a cloud-based visual knowledge management tool that converts complex processes into easy-to-follow, step-by-step visual flows. ProcedureFlow reduces navigation time in the new system and supports more standardized call handling. It also improves consistency, accuracy, and training efficiency while supporting continuous improvement.
- PECO realigned resources to increase CSR coaching and support, including dedicating more leadership resources to provide side-by-side coaching, targeted feedback, refresher training, and peer-to-peer support, as well as "floor walkers" to assist CSRs. These efforts were designed to quickly provide CSRs with assistance on challenging calls and to build CSR confidence and proficiency, which in turn improved customer experience and key performance metrics.
- PECO analyzed First Call Resolution ("FCR") data by call type to identify specific processes, policies, or system issues that were driving repeat calls and to prioritize improvements. PECO was able to link FCR outcomes to training and knowledge gaps, which informed targeted training and updates to scripts and job aids.
- PECO also coordinated with IT and business process owners to remediate system exceptions and streamline workflows that were causing customers to call back.

- PECO increased the number of CSRs throughout 2025. In May 2025, approximately 32 CSRs were added. After several months of training, these CSRs were available for customer calls starting mid-July 2025. Subsequently, an additional 30 CSRs were added and available for customer calls in mid-September, with another 12 available for customer calls by mid-October, totaling 74 new support staff in 2025. As they became more familiar with the CIS and business processes, the CSRs' expertise increased along with call efficiency.
- Improvement in performance metrics was also driven by mitigation of technical issues impacting system availability and performance, including stabilization of the platform and restoration of key self-service capabilities.

17. Q. Have PECO's performance metrics for ASA and Abandon Rate improved since July 2025?

A. Yes. As PECO implemented the performance improvement measures I have described, the Company saw progress throughout 2025 with significant metric improvements realized in Q4 2025.

ASA improved from a weighted average of 216 seconds in the first half of 2025 to 128 seconds in the second half of 2025 (August through December), and the time to reach a CSR was reduced by approximately 41%. In addition, for the period January through February 2026, the year-to-date ASA was 76 seconds as compared to 188 seconds for the same period in 2025, a year-over-year improvement of 60%.

Abandon Rate also experienced similar improvements. During the first half of 2025, the Abandon Rate was 11.20% and in the second half of 2025 (August through December), it was 6.31%, an improvement of 44%. As of February 2026, Abandon Rate further improved to 3.56%, moving significantly closer to the Company's goal of 1.6%. PECO anticipates continued improvement of these metrics throughout 2026.

18. Q. What steps will PECO take to continue to improve customer service performance?

A. Our efforts to continue improvements in customer service will include:

- Targeting and implementing billing refresher training for CSRs to improve accuracy and efficiency when responding to customer billing complaints.
- Onboarding additional contractor agents to stabilize service levels and reduce abandoned calls during elevated call volumes.
- Continuing to review selected customer calls to identify improvement opportunities which may include increased or enhanced training.
- Reviewing and updating as necessary CSR training modules to ensure accuracy and identify potential improvements.

These efforts are designed to maintain the positive trajectory observed in late 2025 and early 2026 and to support sustained compliance with performance expectations.

19. Q. Why did PECO experience an increase in delayed bills?

A. PECO issues over 1.7 million customer bills each month. Utility bills are complex and contain many variables based on customers' preferences. Some of the issues causing delayed bills in the new CIS system were related to customers with new

service or who had transferred their service and locations where we installed new meters or changed out an existing meter. At the start of 2025, billing challenges resulted in approximately one percent of customers experiencing a delayed bill.

20. Q. How did PECO address delayed bills?

A. To address customer issues with delayed bills, PECO expanded staffing by adding more than 60 additional associates, including IT support. We also established a dedicated email address to provide customers with an additional channel to enable PECO to address concerns.

For customers with delayed bills, PECO implemented a variety of additional customer protection measures, including:

- Removing customers with delayed billing issues from the collections process.
- Waiving late payment fee and offering extended payment arrangements, if needed;
- Issuing proactive communications, including special outreach to those enrolled in automatic payment; and,
- When billing delays were resolved, offering payment agreements to customers for two times the number of months their bill was delayed in accordance with regulatory requirements.

PECO continued to work to address the causes that triggered these delayed bills and, as of February 2026, less than 0.1% of our 1.7 million customers are experiencing a delayed bill, a year-over-year improvement of 90%.

21. Q. Have PECO response times for customer complaints increased since the implementation of the new CIS?

A. Yes. PECO's average response times did increase in 2025, primarily driven by the number of informal complaints filed with Bureau of Consumer Services ("BCS"). In 2025, there were approximately 10,100 complaints versus 7,610 in 2023. In 2023, the average response time was 4 days for credit related cases and 13 days for non-credit related cases.

Historically, PECO has utilized the CURE Process in approximately 35% of the informal case complaints received. The CURE Process uses a shortened report to respond to the customer complaint that provides a summary of how PECO and the customer reached an agreement. Beginning in May 2025, the CURE Process was no longer available for PECO's utilization. As a result, additional time was needed to process responses for each case. The increased number of cases and the increased amount of time required to process the cases were drivers to the increased response time.

22. Q. What measures has PECO taken to improve the average response time for customer complaints?

A. In 2025, PECO hired an additional 15 contractors to support responses to increased customer informal complaints. Additionally, three full-time equivalent positions were added to the team responsible for responding to informal complaints. The team also reviewed its existing processes to identify efficiencies needed when working in the new customer information system and across internal groups.

VI. WAIVER OF CERTAIN RECONNECTION FEES FOR ELIGIBLE CONFIRMED LOW-INCOME CUSTOMERS

23. Q. What are reconnection fees?

A. If PECO terminates a customer's service by reason or act of the customer, including nonpayment of utility bills, that customer is required to pay a reconnection fee (along with any required restoration amount) prior to PECO restoring service. Reconnection fees are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs.

24. Q. What is PECO proposing in this rate case related to reconnection fees?

A. PECO recognizes that reconnection fees may be an additional barrier for low-income customers that intend to restart utility service after their service has been discontinued or terminated for non-payment. PECO is proposing to waive the reconnection fees for electric remote reconnect ($20 per reconnection) for confirmed low-income customers[3] whose service has been discontinued or terminated for non-payment. The proposed tariff changes to implement this waiver are shown in PECO Exhibit JAB-2.

25. Q. How many confirmed low-income customers does PECO normally terminate for nonpayment on an annual basis?

A. On average, PECO terminates approximately 20,000 confirmed low-income customers for nonpayment on an annual basis.

[3] PECO defines "confirmed low-income" as customers who, in the last two years, have provided verified financial information (i.e., proof of income documentation) at or below 150% of FPL, and/or enrolled in CAP, and/or received a LIHEAP grant.

26. Q. What is the estimated cost of this fee waiver proposal?

A. PECO estimates that this proposal will cost $0.4 million per year.

VII. PAYMENT PROCESSING FEES

27. Q. Does PECO have a rate case commitment regarding residential payments by credit card and the fee charged per transaction?

A. Yes. As part of the settlement of PECO's last electric base rate proceeding, the Company agreed to the following term:

> In its next base rate filing, PECO will: (1) provide, for the most recent 24 months available (a) the monthly number of residential payments by credit card and the fee charged per transaction and (b) the monthly number of residential payments by debit card and the fee charged per transaction; and (2) propose to eliminate all payment processing fees, including credit card and debit card fees imposed by third parties, when not using "MyAccounts," e.g., online "pay as guest" or phone payments or, if PECO fails to make this proposal, it will provide detailed information supporting its decision.

28. Q. Is PECO providing the information described in subpart (1) of the commitment?

A. Yes. Please see PECO Exhibit JFG-1, which provides the requested data for the most recent 24 months.

29. Q. Is PECO proposing to eliminate all payment processing fees including credit card and debit card fees imposed by third parties, when not using "MyAccounts"?

A. No. As I explain below, the Company does not believe it is appropriate to collect the substantial annual costs of payment processing fees, including credit card and debit card fees imposed by third parties, from customers. As shown in PECO Exhibit JFG-1, for the most recent 24 months, the average fees for residential payments (electric and gas combined), totaled more than $6 million per 12-month

period. In addition, fees associated with residential payments made through the pay as a guest option, using their banking information, on average were approximately $500,000 for a 12-month period (electric and gas combined).

30. Q. Does the Company offer no-fee payment options for customers to pay their bills?

A. Yes. The Company does offer, and intends to continue to offer, multiple no-fee payment options for customers.

31. Q. What types of no-fee payment options are available for customers to pay their bills?

A. No-fee options include mailing payments directly through the United States Postal Service, submitting an electronic payment (e-check) via PECO's "MyAccount" (on PECO's website or mobile phone app), electronic payment through the customer's bank or third-party institution, or using agent-assisted e-check payments for customers who have a MyAccount but wish to pay by phone. The Company also has authorized bill payment locations (e.g., large retail stores and drug stores) where customers can pay their bill. While a payment fee of $2.00 is initially charged by the third-party vendor to customers who make payments at authorized bill payment locations via check, cash, credit or debit card, those payment fees are reimbursed to the customer on the customer's next bill by PECO.

Historically, we have seen approximately 250,000 payments (electric and gas combined) made at authorized bill payment locations over the course of a 12-month period. These locations are throughout our service territory with approximately 70% (74 of the 106 locations) in the City of Philadelphia, where a

majority of PECO's residential low-income customers are geographically located. The fees associated with payments made at authorized bill payment locations are recovered from customers through base rates at an average annual cost of approximately $0.4 million for electric customers, based on a historical allocation of 86% for electric and 14% for gas.

32. Q. What other payment options are available for residential customers?

A. In addition to no-fee options mentioned above, residential customers can make payments using a debit or credit card. When utilizing this option through making a payment online or via the IVR (Interactive Voice Response System), for example, fees associated with the processing of debit and credit card payments are collected by a third-party vendor to offset the credit card fees assessed by the credit card industry. PECO does not charge any amounts in addition to the third-party vendor fee.

33. Q. What is the current fee charged by the third-party vendor to residential customers for processing a payment utilizing a credit or debit card?

A. Currently there is a $2.25 flat fee charged per credit or debit card transaction.

34. Q. Why isn't PECO proposing to eliminate this fee?

A. As shown in PECO Exhibit JFG-1, the fees associated with the processing of residential, debit and credit card payments, electric and gas combined, were approximately $6.5 million for more than 3.1 million transactions processed for March 2024 through February 2025. For the period March 2025 through February 2026, the fees were approximately $7.8 million for over 3.4 million transactions processed. The average across these two periods for the associated fees was $7

million, with nearly 3.3 million residential transactions processed. As a comparison, for the period March 2022 through February 2023, the fees were approximately $5 million for about 2.8 million transactions processed.

PECO has seen an increased utilization of this payment method. Residential payment transactions have grown by nearly 15% since 2022, based on the same 12-month period. If the number of transactions continues to grow, PECO would expect the annual amount of processing fees would grow as well.

PECO does not disaggregate third-party payment fees by electric and gas. However, if PECO were to apply the allocation of 86% electric and 14% gas, based on the split used for authorized bill payment locations referenced above, to the recovery of these fees, the electric residential revenue requirement would increase by approximately $6 million annually at current transaction levels. This $6 million increase does not include fees associated with residential customers who pay as a guest using their banking information. These payments also have an associated fee of $2.25 per transaction and historically have totaled approximately $0.5 million annually, which would further increase the revenue requirement.

PECO does not believe that the inclusion of these residential payment fees in its revenue requirement is reasonable, especially given that this amount would then be collected from all residential customers, including those currently using the no-fee payment option.

PECO does recognize that credit card companies can charge significant fees for payments or purchases. To minimize the impact to our customers, PECO works with our payment processing vendor during contract negotiations to ensure

reasonable payment processing fees for our residential customers. Notably, as part of the settlement of PECO's last electric base rate proceeding, the Company agreed to undertake a good-faith effort to negotiate lower payment processing fees with third-party vendors when it negotiates its next contract (anticipated to be in 2028). The Company will also continue to support reimbursement of transaction fees for payments made at our authorized bill payment locations.

VIII. CONCLUSION

35. Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060859**
PECO ENERGY COMPANY - ELECTRIC DIVISION	:	

VERIFICATION

I, Jacqueline F. Golden, hereby state that I am a Director of Customer Financial Operations for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 12 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Jacqueline F. Golden

Dated: March 30, 2026

PECO Exhibit JFG-1:
Credit / Debit Fee Information

Credit Card

Month	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Total
Volume	201,732	200,149	204,963	196,004	229,037	232,601	145,735	58,688	56,264	53,037	55,112	53,916	58,150	58,575	60,938	58,374	65,875	66,387	66,341	67,533	62,826	65,187	66,191	44,662	2,428,277
Fee	$1.75	$1.75	$1.75	$1.75	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	
Total	$353,031	$350,261	$358,685	$343,007	$515,333	$523,352	$327,904	$132,048	$126,594	$119,333	$124,002	$121,311	$130,838	$131,794	$137,111	$131,342	$148,219	$149,371	$149,267	$151,949	$141,359	$146,671	$148,930	$100,490	$5,062,199

Debit Card

Month	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Total
Volume	49,831	48,291	48,811	44,091	55,415	57,185	113,811	214,784	206,942	183,222	197,794	194,191	207,403	216,928	231,086	213,598	237,688	242,291	232,863	249,339	216,587	213,073	215,894	142,597	4,033,715
Fee	$1.75	$1.75	$1.75	$1.75	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	$2.25	
Total	$87,204	$84,509	$85,419	$77,159	$124,684	$128,666	$256,075	$483,264	$465,620	$412,250	$445,037	$436,930	$466,657	$488,088	$519,944	$480,596	$534,798	$545,155	$523,942	$561,013	$487,321	$479,414	$485,762	$320,843	$8,980,347