PECO ENERGY COMPANY
STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2018-3000164

DIRECT TESTIMONY

WITNESS: PAUL R. MOUL

SUBJECT: PECO'S OVERALL RATE OF RETURN
INCLUDING CAPITAL STRUCTURE
RATIOS, EMBEDDED COST OF DEBT,
AND THE COST OF EQUITY

DATED: MARCH 29, 2018

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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
Company	PECO Energy Company
CTC	Competitive Transition Charge
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
ITC	Intangible Transition Charge
Lev	Leverage modification
LT	Long Term
MLP	Master Limited Partnerships
OCI	Other Comprehensive Income
PECO	PECO Energy Company
PUC	Pennsylvania Public Utility Commission
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY
OF
PAUL R. MOUL

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

1. Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

2. Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission (“PUC” or the “Commission”) should recognize in the determination of the revenues that PECO Energy Company (“PECO Energy” or the “Company”) should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in PECO Energy Exhibit PRM-1, which is a multi-page document divided into fourteen (14) schedules. My testimony is based upon my first-hand knowledge of PECO Energy, consisting of information obtained from meetings with the Company's management and

Company-specific data that is widely disseminated within the financial community.

3. Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity in the range of 10.16% to 11.25%. From this range, a 10.95% rate of return on common equity is proposed for the Company in this case. My 10.95% cost of equity recommendation is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company. My cost of equity determination should be viewed in the context of increasing capital costs revealed by rising interest rates and the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. Moreover, as I will describe below, there will be more risk faced by the Company with the changes to tax law recently passed by the U.S. Congress and signed into law by the President on December 22, 2017. My analysis of the Company and its superior performance, as described in the testimony of Mr. Michael A. Innocenzo, the Company's Senior Vice President and Chief Operating Officer, and other Company witnesses justify a rate of return near the top of the range. As shown on Schedule 1, I have calculated a 7.79% overall cost of capital for the Company at December 31, 2019. This figure, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, will set a compensatory level of return for the use of capital and provide the Company with the ability to attract capital on reasonable terms.

4. Q. What background information have you considered in reaching your conclusion concerning the Company's cost of capital?

A. The Company is a wholly owned subsidiary of Exelon Corporation ("Exelon"). The common stock of Exelon is traded on the New York Stock Exchange. Exelon is a component of the S&P 500 Composite Index. PECO Energy provides electric delivery service to approximately 1,624,000 residential, commercial and industrial electric customers in both the City of Philadelphia and the surrounding counties. The Company also provides natural gas distribution service to approximately 522,000 customers located in the suburban counties surrounding the City of Philadelphia. Deliveries of electricity to the Company's customers through December 2017 were comprised of approximately 35% to residential customers, approximately 21% to commercial customers, approximately 41% to industrial customers, and approximately 2% to street lighting, railroads, and sales for resale. With industrial customers representing 41% of sales, the energy needs of just 0.2% of all customers can have a significant impact on the Company's operations. PECO Energy obtains all of its electric energy for default service from third parties.

5. Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital-market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for an electric-delivery utility. In this regard, I have considered four (4) well-recognized models. These methods include: The Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

6. Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The rate of return utilized by the Commission to set rates must be sufficient to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

7. Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of ten (10) electric and combination utility companies. The proxy group consists of electric companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, and (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant. The companies that comprise the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

8. Q. How have you performed your cost-of-equity analysis with the market data for the Electric Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Electric Group. I have not measured separately the cost of equity for the individual companies within the Electric Group because the determination of the cost of equity for an individual company can be problematic. My approach of using average data for a portfolio of companies reduces the possibility that anomalous results might be shown by the models of the cost of equity if individual companies are employed separately. By employing group average data, rather than analyzing individual companies, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

9. Q. Please summarize your cost-of-equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF	10.71%
Risk Premium	11.25%
CAPM	10.16%
Comparable Earnings	12.35%

Based on various combinations of the model results shown above, the average of the market based models (i.e., DCF, RP, CAPM) is 10.71% (10.71% + 11.25% + 10.16% = 32.12% ÷ 3) and the average of all methods is 11.12% (10.71% + 11.25% + 10.16% + 12.35% = 44.47% ÷ 4). I have used these measures of central tendency to arrive at a range of the cost of equity of 10.16% to 11.25%. Therefore, I recommend that the Commission set the Company’s rate of return on common equity near the top of the range, which for this case I recommend as 10.95%. My recommendation of 10.95% reflects the exemplary performance of the Company's management. As described in the testimony of Company witness Michael Innocenzo and other Company witnesses, PECO Energy has undertaken many initiatives that have produced high-quality service. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements.

II. ELECTRIC UTILITY RISK FACTORS

10. Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Utilities continue to face the risks associated with their traditional responsibilities to maintain distribution system reliability under all weather conditions, including major storm events, and to comply with the mandates of their regulators. In addition, a different set of risks now exists for the electric delivery business in Pennsylvania. The potential expansion of distributed generation will have an increasing influence on the business of electric-delivery utilities. The obligation to serve represents a key risk factor for the local delivery of electricity. The risks facing the electric utilities are clearly different from those that existed in the past. Investors generally are risk-averse, and with increased uncertainty will require compensation for higher risk.

11. Q. What are the primary risk factors facing the electric-utility industry?

A. Electric utilities generally are faced with meaningful changes in the fundamentals that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate its business profile. The risk of distributed generation is a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues. That is to say, the development of distributed generation and local alternative energy has the potential to displace delivery revenue that can impact the incumbent utility's financial profile. This risk is exacerbated by net metering rules that require offsets against distribution rates even though distribution costs may not be reduced as a result of the installation of distributed generation.

Utilities also face cybersecurity risks, which require increased expenditures to harden their information technology and data transmission systems. They also face potential liability if a cyberattack or similar unforeseen intrusions were to occur.

The cost to replace aging infrastructure and to enhance reliability and resiliency also adds to the risk of electric delivery utilities, such as PECO Energy, because these expenditures increase costs without any concomitant increase in revenues, except through regulatory agency-approved rate increases, such as the Distribution System Improvement Charge ("DSIC"). The Company continues to make substantial investments to harden its system and expand its vegetation management practices to reduce the number and duration of storm-related outages experienced by customers. The DSIC contains a variety of limitations that will not eliminate the need for periodic rate cases to cover the significant new investment that is being made by PECO Energy. Since 2011, PECO Energy has also been engaged in an energy efficiency and conservation ("EE&C") program, pursuant to the programs mandated by Act 129 of 2008, P.L. 1592 ("Act 129"). Reductions in revenues resulting from reductions in usage and demand the Company is required to achieve under its Commission-mandated EE&C program can be reflected only on a prospective basis in base rate cases.

12. Q. Are there other specific risk issues facing the Company?

A. Yes. Industrial customers, which account for 41% of the Company's energy deliveries, are usually thought to be of higher risk than residential customers. Indeed, the energy requirements of the Company's ten largest customers of 4.5 GWh represent approximately 16% of its total energy deliveries for the year 2017. This represents a significant concentration of deliveries to a few customers that increases the Company's risk. Success in this segment of the Company's market is subject to the business cycle and pressures from alternative providers. Moreover, external factors can influence deliveries to these customers, which face competitive pressure on their own operations from other facilities outside the utility's service territory.

13. Q. Please indicate how the Company's risk profile is affected by its construction program.

A. The Company must undertake substantial investments to maintain, upgrade and expand existing facilities in its service territory to ensure safe and reliable service to its customers. In particular, the rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company projects its construction expenditures for its electric distribution business will be approximately $2.508 billion during the period 2018-2022, which represents approximately 55% ($2.508 billion ÷ $4.565 billion) of its net distribution plant at December 31, 2017.

14. Q. You indicated previously that the recent federal income tax law changes will add to the Company's risk. Please explain.

A. There are several major financial consequences that flow from the recent changes in the federal income tax law that will negatively affect the Company. First, a lower federal income tax rate (21% versus 35%) will lower the Company's pre-tax interest coverage and, therefore, will reduce its credit quality and increase risk. For example, page 1 of Schedule 1 shows that with a 21% marginal federal corporate income tax rate, the Company's pre-tax interest coverage will be 5.24 times at its proposed distribution rates. Under the pre-2019 marginal federal corporate income tax rate of 35%, the

Company's pre-tax interest coverage would have been 6.15 times. That difference in coverage ratios does not reflect other changes driven by the tax law changes that may also impact the Company's financial condition and credit quality, such as the flow-back of so-called "excess" accumulated deferred income taxes ("ADIT"). Second, with a lower marginal federal corporate income tax rate, the variability of the Company's returns will increase, which also increases its business risk. When the federal corporate income tax rate was 35%, investors only needed to absorb 65% of any changes in revenues and expenses. This happens because the Company had a tax benefit equal to 35% of any increase in deductible expenses or 35% of any decrease in taxable revenue. At the current federal corporate income tax rate, the tax benefit is reduced to 21% and, therefore, investors will need to absorb 79% of any increase in expenses or reduction in revenue. As a result, lower federal income taxes will make investor returns more volatile than before the tax rate change occurred, and volatility translates into increased risk to the Company. Third, utilities will require more investor-supplied capital to fund construction programs because the level of deferred taxes will decline, the new tax law eliminates bonus depreciation, and "excess" ADIT created by the reduction in the federal corporate income tax rate will have to be flowed back to customers. This will also impact another credit metric that is important to capital-intensive industries such as electric utilities, namely, internally generated funds as a percentage of construction expenditures. This percentage will decline because of the new lower income tax rate. In response to these financial challenges caused by the new lower federal corporate income tax rate, there may be a need to reduce the percentage of debt in a utility's capital structure to respond to higher business risk and weaker credit quality measures.

15. Q. How should the Commission respond to the evolving business environment facing the Company?

A. In the situation where additional capital is required, as shown by the projected construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. Where ongoing capital investment is required to meet the high quality of service that customers demand, supportive regulation is essential.

III. FUNDAMENTAL RISK ANALYSIS

16. Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for determining a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared PECO Energy to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Electric Group.

17. Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

18. Q. What companies comprise your Electric Group?

A. My Electric Group obtained from the Value Line Investment Survey consists of the following companies: AVANGRID, Inc., Consolidated Edison, Dominion Energy, Duke Energy, Eversource Energy, Exelon Corp., FirstEnergy Corp., NextEra Energy, PPL Corp., and Public Service Enterprise Group.

19. Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit-quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit-quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

20. Q. How do the bond ratings compare for PECO Energy, the Electric Group, and the S&P Public Utilities?

A. Currently, the Long Term ("LT") issuer rating for PECO Energy is A2 from Moody's Investors Services ("Moody's") and the corporate credit rating ("CCR") is BBB from Standard and Poor's Corporation ("S&P"). The LT issuer rating by Moody's and CCR designation by S&P focus upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The average credit quality of the Electric Group is Baa1 from Moody's and BBB+ from S&P. For the S&P Public Utilities, the average composite rating is A3 by Moody's and BBB+ by S&P. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

21. Q. How do the financial data compare for PECO Energy, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2012-2016. For PECO Energy, the financial statements contained in SEC Form 10-K, which is the source used by S&P Utility Compustat, include both its natural gas distribution and electric delivery and transmission businesses. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, PECO Energy is smaller than the average size of the Electric Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

There are no market ratios available for PECO Energy because Exelon owns its stock. The five-year average price-earnings multiple was higher for the Electric Group than for the S&P Public Utilities. The five-year average dividend yield for the Electric Group was also somewhat higher than the S&P Public Utilities. The average market-to-book ratios were somewhat lower for the Electric Group than the S&P Public Utilities.

Common-Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing

[2] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

common-equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common-equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common-equity ratios, based on permanent capital, were 55.8% for PECO Energy, 48.2% for the Electric Group, and 44.3% for the S&P Public Utilities. For the purpose of calculating the weighted average cost of capital for this case, the Company is proposing a 53.39% common equity ratio.

Return on Book Equity. Greater variability (*i.e.*, uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.056 (0.7% ÷ 12.4%) for PECO Energy, 0.046 (0.4% ÷ 8.7%) for the Electric Group, and 0.022 (0.2% ÷ 9.2%) for the S&P Public Utilities. Here, PECO Energy displays somewhat more risk due to its higher coefficient of variation than the Electric Group. Also, its coefficient of variation is higher than the S&P Public Utilities. This signifies higher risk for PECO Energy compared to the Electric Group. And, as I indicated previously, the recent changes in the federal income tax law will likely make these variability statistics higher in the future.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 79.1% for PECO Energy, 77.8% for the Electric Group, and 80.4% for the S&P Public Utilities. The operating ratio for PECO Energy is fairly close to the Electric Group, which indicates similar risk.

Coverage. The level of fixed-charge coverage (*i.e.*, the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 5.34 times for PECO Energy, 3.56 times for the Electric Group, and 3.15 times for the S&P Public Utilities. The higher interest coverage for PECO Energy suggests lower credit risk. Again, these indicators will decline prospectively with the implementation of the pending federal income tax changes.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because

[3] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for PECO Energy, the Electric Group, or the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 82.7% for PECO Energy, 81.3% for the Electric Group, and 70.5% for the S&P Public Utilities. This indicates a fairly comparable risk for the Company and the reference groups. As noted previously, the IGF to construction expenditures will decline with the new lower federal income tax rate.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, *i.e.*, the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .66 as the average for the Electric Group (see page 2 of Schedule 3), and .75 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

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[4] The procedure used to calculate the beta coefficient published by Value Line is described in Appendix H. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

22. Q. Based on your analysis, does the Electric Group provide a reasonable basis to measure the Company's cost of equity for this case?

A. Yes. Some risk indicators are higher for the Company, some are lower, and others are about the same. On balance, the risk factors average out, indicating that the cost of equity for the Electric Group provides a reasonable basis for measuring the Company's cost of equity.

IV. CAPITAL STRUCTURE RATIOS

23. Q. Please explain the selection of capital structure ratios for PECO Energy.

A. The capital structure ratios of PECO Energy should be employed for rate of return purposes. In the situation where the operating public utility raises its own debt directly in the capital markets, as is the case for the Company, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate-of-return purposes. Furthermore, consistency requires that the embedded cost rates of the Company's senior securities also be employed. This procedure is consistent with the ratesetting procedures used by the Commission in prior rate cases for PECO Energy.

24. Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

A. Yes. The December 31, 2017 capitalization corresponds with the end of the historic test year in this case, December 31, 2018 date corresponds with the end of the future test year, and December 31, 2019 date corresponds with the end of the fully projected test year. In the future test year, the Company plans to issue $700 million of new long-term debt. This will consist of a $325 million bond issue that was actually issued February 23, 2018, a $325 million bond issue planned for September 2018, and $50 million of debt to be issued to the Philadelphia Industrial Development Corporation ("PIDC") also in September 2018. For the fully projected test year, there is a $250 million bond issue planned in September 2019. Future equity financings include $75.159 million in the future test year and $151.856 million in the fully projected test year. The build-up of retained savings is also reflected. In presenting the Company's capital structure on Schedule 5, I have removed several items for ratesetting purposes, including the treatment of the call premiums on the early redemption of high-cost long-term debt and preferred stock, which has been redeemed, and the accumulated Other Comprehensive Income ("OCI").

25. Q. Please describe the adjustment for the call premiums paid to redeem the high-cost debt.

A. I have adjusted the principal amounts of long-term debt and preferred stock to exclude the amounts used to finance premiums on the early redemption of these securities. To do otherwise would deny PECO Energy the full return on the premiums paid to redeem this high-cost capital since additional amounts of capital were issued to pay the call premiums. The amounts issued to finance the call premiums do not increase the Company's rate base. That is to say, no additional rate base was created through additional debt and preferred stock necessary to finance this transaction, and therefore an adjustment is required to provide the return necessary to service this additional capital. Hence, PECO Energy's long-term debt and preferred stock amounts must be adjusted for this disparity in order that the return necessary to service the capitalization is produced from rate base investment times the overall rate of return.

This adjustment is equitable because customers receive the cost savings resulting from these refinancings in the form of a lower overall rate of return, and PECO Energy recovers all costs incurred in providing these benefits to customers. To produce these savings, the Company paid to the debt and preferred stock holders a premium for surrendering their securities prior to maturity. These premiums represented an investment made by PECO Energy to reduce its overall cost of capital. Because the reduced interest costs and preferred stock dividends are reflected in the lower cost of capital to customers, it is appropriate that the Company recover the costs incurred to produce these savings. This includes both a return of and return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides a return on the premium as a part of the embedded cost rates of capital.

26. Q. Please describe the OCI adjustment.

A. I have removed the accumulated OCI from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability, foreign-currency hedges, unrealized gains and losses on securities available for sale, interest-rate swaps, and other cash-flow hedges. For PECO Energy, its OCI is represented by Unrealized Gains and Losses on Available-for-Sale Securities. The accounting entries that relate to accumulated OCI are unrelated to the Company's rate base determination and must be excluded from the common-equity balance. That is to say, these accounting entries neither produce nor consume cash, and hence they cannot impact the rate base valuation.

27. Q. Should short-term debt be included in the capital structure for rate of return purposes?

A. There is no need to consider short-term debt in the capital structure because PECO Energy does not have any short-term debt at the end of the historical and future test years and for the fully projected test year. Moreover, short-term debt is typically assumed to finance construction work in progress ("CWIP"), and the cost of short-term debt is reflected in the AFUDC rate.

28. Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratesetting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the test year. As a result, I will adopt the Company's fully projected test year-end capital structure ratios of 46.61% long-term debt and 53.39% common equity.

V. COSTS OF SENIOR CAPITAL

29. Q. What cost rate have you assigned to the debt portion of PECO Energy's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is because the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on pages 1, 2 and 3 of Schedule 6, I have computed the embedded cost rate of long-term debt at the end of each test year. On page 3 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at December 31, 2019. The actual effective cost for the new issue that was sold on February 23, 2018 was 3.99%, including issuance costs. For the planned new issues of debt, the Company has budgeted 4.08% including issuance costs for the First Mortgage Bonds to be sold in September 2018, 2.24% including issuance costs for the PIDC issue in September 2018, and 4.15% including issuance cost for the First Mortgage Bond scheduled for September 2019. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity ("ytm"), is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond. In my calculation of the embedded cost of long-term debt, I have recognized the costs associated with the Company's early redemption of high cost debt. As previously explained, it is necessary to compensate PECO Energy for the costs incurred to lower the embedded debt cost rate, which reduces the cost of capital charged to customers.

30. Q. What cost rate have you determined for the Company's long-term debt?

A. I will adopt the 4.16% embedded cost of long-term debt at December 31, 2019, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 46.61% long-term debt ratio.

VI. COST OF EQUITY – GENERAL APPROACH

31. Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among PECO Energy, the Electric Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group and arrived at a cost of equity of 10.95% for PECO Energy, which includes recognition of strong management performance.

VII. DISCOUNTED CASH FLOW ANALYSIS

32. Q. Please describe the Discounted Cash Flow model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

are provided on page 2 of Schedule 1 for the Electric Group. The DCF return is 10.71%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

33. Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by dividend receipts. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended December 2017, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended December 2017 the average dividend yield was 3.73% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.62% and 3.56%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.62% for the Electric Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor-anticipated cash flows for the Electric Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds eleven basis points to the six-month average historical yield, thus producing the 3.73% adjusted dividend yield for the Electric Group.

34. Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share represents the DCF model's primary focus because, under the model's assumption of a constant price-earnings multiple, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including:

earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts, which are those used by investors when pricing common stocks.

35. Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner.

36. Q. How did you determine an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

37. Q. What data for the Electric Group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 8 and 9. In this regard, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks. Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept and, with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So, with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio. The historical growth rates were taken from the Value Line publication that provides this data. As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, assigning significant weight to historical performance results in double counting of the historical data. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance. As shown on Schedule 8, the historical growth of earnings per share was in the range of -0.06% to 3.33% for the Electric Group. Negative growth that occurred in the past is not reflective of investor expectations for the future that encompass positive returns.

38. Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes. The constant form of the DCF assumes an infinite stream of cash flows, but investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication suggests that there is no market for this information, because investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

39. Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 9 for the Electric Group.

40. Q. What are the projected growth rates published by the sources you discussed?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Electric Group are 4.27% by IBES/First Call, 5.24% by Zacks, 5.75% by Morningstar, 4.78% by SNL and 6.06%% by Value Line. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

41. Q. What other factors did you consider in developing a growth rate?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[6] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, SNL, and Value Line, represent a reasonable assessment of investor expectations.

42. Q. What growth rate do you use in your DCF model?

A. The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 4.27% to 6.06%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.75% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. Indeed, my 5.75% growth rate is obtained from the analysts' growth forecasts that cover a five-year period, which are the growth rates that investors employ for DCF purposes. Improved economic growth supports a DCF growth rate near the high end of the range. Economic growth is expected to accelerate as a result of the stimulus provided by the recent federal corporate income tax changes.

[6] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

43. Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Electric Group, those average capital structure ratios are 42.95% long-term debt, 0.06% preferred stock, and 56.99% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

44. Q. What is a leverage adjustment?

A. Where a firm's capitalization, as measured by its stock price, diverges from its book value capitalization, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value. A leverage adjustment accounts for this difference between market value and book value capital structures.

45. Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes) the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Electric Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the rate setting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the rate setting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M," provides a return of 7.39% when applicable to a capital structure with 100% common equity.

46. Q. Are there specific factors that influence market-to-book ratios that need to be taken into account in order to determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning variations of market prices relative to book value are not relevant. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result into a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. While stock prices above book value are common for utility stocks, the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of January 22, 2018, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.98 times book value, which is below the market multiple of other indices.

For example, the S&P Industrial index was at 4.82 times book value, and the Dow Jones Industrial index was at 4.50 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

47. Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.39%, which is the return for the Electric Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 3.32% compensation for having a 54.49% debt ratio, plus 0.00% for having a 0.08% preferred stock ratio. The sum of the parts is 10.71% (7.39% + 3.32% + 0.00%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.73% dividend yield, the 5.75% growth rate, and the 1.23% for the leverage adjustment in order to arrive at the same 10.71% (3.73% + 5.75% + 1.23%) return. I know of no means to mathematically solve for the 1.23% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.23% adjustment is merely a convenient way to compare the 10.71% return computed directly with the Modigliani & Miller formulas to the 9.48% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF -- see page 1 of Schedule 7) based on a market value capital structure. A 9.48% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

48. Q. What does your DCF analysis show?

A. As explained previously, I have utilized a six-month average dividend yield ("D_{1}/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the rate setting process rather than the market value equity ratio related to the price of stock.

	D_1/P_0	+	g	+	$lev.$	=	k
Electric Group	3.73%	+	5.75%	+	1.23%	=	10.71%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity. In the current environment of rising interest rates, the DCF method tends to be less responsive to (i.e., lags) changes in those rates. As such, other methods for measuring the cost of equity, e.g., Risk Premium and CAPM, should be emphasized because they respond promptly to change in interest rates.

VIII. RISK PREMIUM ANALYSIS

49. Q. Please describe your use of the risk premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.25%.

50. Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 4.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

51. Q. Please explain what is shown in Schedule 11.

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the twelve months ended December 2017, the average monthly yield on Moody's index of A-rated public utility bonds was 4.00%. For the six and three-month periods ended December 2017, the yields were 3.88% and 3.84%, respectively. During the twelve-months ended December 2017, the range of the yields on A-rated public utility bonds was 3.79% to 4.23%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.10% on a twelve-month average basis, 1.06% on a six-month average basis, and 1.03% on a three-month average basis. From these averages, 1.00% represents a conservative spread for the yield on A-rated public utility bonds over Treasury bonds.

52. Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the <u>Blue Chip Financial Forecasts</u> ("<u>Blue Chip</u>") along with the spread in the yields that I describe below. <u>Blue Chip</u> is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, <u>Blue Chip</u> stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2018, and a yield spread of 1.00%, derived from historical data.

53. Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2018	First	3.8%	4.5%	3.0%	1.00%	4.00%
2018	Second	4.0%	4.7%	3.1%	1.00%	4.10%
2018	Third	4.2%	4.9%	3.3%	1.00%	4.30%
2018	Fourth	4.4%	5.1%	3.4%	1.00%	4.40%
2019	First	4.5%	5.2%	3.5%	1.00%	4.50%
2019	Second	4.6%	5.4%	3.6%	1.00%	4.60%

54. Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2017 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2019-2023	5.1%	6.0%	4.1%
2024-2028	5.4%	6.2%	4.3%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. By focusing more on these forecasts, a 4.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. In reaching my conclusion as to a prospectively yield on A-rated public utility debt, I have considered the data relied upon by investors.

55. Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2017 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 12.

Common Equity Risk Premiums		
Low Interest Rates		7.08%
Average Across All Interest Rates		5.64%
High Interest Rates		4.18%

Based on my analysis of the historical data, the equity risk premium was 7.08% when the marginal cost of long-term government bonds was low (i.e., 2.96%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.22% on average during periods of high interest rates) the spread narrowed to 4.18%. Over the entire spectrum of interest rates, the equity risk premium was 5.64% when the average government bond yield was 5.07%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.08% premium related to periods of low interest rates and the 5.64% premium related to average interest rates across all levels.

56. Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*
Electric Group	4.75%	+	6.50%	=	11.25%

Indeed, in an environment of rising interest rates, the Risk Premium model provides a direct reflection of the cost of equity that captures higher interest rates.

IX. CAPITAL ASSET PRICING MODEL

57. Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 10.00%. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

58. Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.66 for the Electric Group.

59. Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the rate setting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[7] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.44 for the Electric Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada" who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 0.78 for the book value capital structure of the Electric Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.78 for the Electric Group.

60. Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2017, the

[7] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp. 435-452.

average yield on 30-year Treasury bonds was 2.90%. For the six- and three-months ended December 2017, the yields on 30-year Treasury bonds were 2.82% and 2.82%, respectively. During the twelve-months ended December 2017, the range of the yields on 30-year Treasury bonds was 2.77% to 3.08%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). Essentially, low interest rates were the product of the policy of the Federal Open Market Committee ("FOMC") in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC ended its bond purchasing program. At its December 16, 2015 meeting, the FOMC increased the federal funds rate range by 0.25 percentage points. On December 14, 2016, the FOMC acted again by raising the Fed Funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC increased the fed funds rate on three occasions in 2017 (i.e., March 15, 2017, June 14, 2017 and December 13, 2017) by one-quarter percentage point each. The Wall Street Journal has also reported that three one-quarter percentage point rate increases are anticipated for 2018 and two one-quarter percentage point rate increases will likely follow in each of the years 2019 and 2020. This buttresses the prospect that higher interest rates are on the horizon.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2018 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.0% to 3.6% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.1% from 2019 through 2023 and 4.3% from 2024 to 2028. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

61. Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 11.97% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.96% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 11.96% (11.97% + 11.95% = 23.92% ÷ 2) and the average yield on long-term government bonds of 4.02% (2.96% + 5.07% = 8.03% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 7.94% (11.96% - 4.02%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated an 11.83% DCF return for the S&P 500. Normally, I would also include the Value Line forecast data as part of the market premium calculation. But in this instance, the Value Line result of 7.64% is clearly anomalous. I say this because those forecasts are established by Value Line in a hypothesized economic environment three to five years in the future. However, given when the Value Line forecasts were made, they would have hypothesized an economic environment with real GDP growth of approximately 2.5%. With the recent changes in the federal tax law, GDP is expected to increase from that level. As such, I have suspended the use of the Value Line forecast for the purpose of this case. With the forecast return of 11.80%, I calculated a market premium of 8.08% (11.83% - 3.75%) using the S&P 500 forecast data. Indeed, this forecast market premium is more in-line with historical evidence. The market premium applicable to the CAPM derived from these sources equals 8.01% (8.08% + 7.94% = 16.02% ÷ 2).

62. Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.78 for the Electric Group, and the 8.00% market premium, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	)	=	*k*
Electric Group	3.75%	+	0.78	x (	8.01%	)	=	10.00%

X. COMPARABLE EARNINGS APPROACH

63. Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> 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. 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.[8]

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

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[8] Bluefield Water Works & Improvement Co., 262 U.S. at 692-93.

64. Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definitions for these parameters are provided on page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

65. Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential for improper specification inherent in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 11.7% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 13.0% also using values less than 20%, as provided on page 2 of Schedule 15. Using the average of these data my Comparable Earnings result is 12.35%, as shown on page 2 of Schedule 1.

XI. CONCLUSION

66. Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.95% for PECO Energy, which includes recognition of the Company's strong performance in the area of management performance. My cost of equity recommendation is obtained from a range of results (i.e., 10.60% to 11.00%) and should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets, and the strong performance of the Company's management. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

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

A. Yes, it does.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

PECO ENERGY COMPANY

Schedules to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

and

Fair Rate of Return

PECO ENERGY COMPANY
Index of Schedules

PECO Energy Company

Proposed Rate of Return
Estimated at December 31, 2019

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.61%	4.16%	1.94%
Common Equity	53.39%	10.95%	5.85%
Total	100.00%		7.79%

Indicated levels of fixed charge coverage assuming that
the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a 28.8921% composite federal and state income tax rate (10.17% ÷ 1.94%)	5.24 x
Post-tax coverage of interest expense (7.79% ÷ 1.94%)	4.02 x

PECO Energy Company
Cost of Equity
as of December 31, 2017

Discounted Cash Flow (DCF)	D_1/P_0 [1]	+	g [2]		+	*lev.* [3]		=	*k*
Electric Group	3.73%	+	5.75%		+	1.23%		=	10.71%
Risk Premium (RP)			*I* [4]		+	*RP* [5]		=	*k*
Electric Group			4.75%		+	6.50%		=	11.25%
Capital Asset Pricing Model (CAPM)	*Rf* [6]	+	*ß* [7]	x	(	*Rm-Rf* [8]	)	=	*k*
Electric Group	3.75%	+	0.80	x	(	8.01%	)	=	10.16%
Comparable Earnings (CE)			***Historical*** [9]			***Forecast*** [9]			**Average**
Comparable Earnings Group			11.7%			13.0%			12.35%

References
(1) Schedule 07 page 1
(2) Schedule 09 page 1
(3) Schedule 10 page 1
(4) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return (Schedule 13 page 2) and a yield spread of 1.00% (Schedule 11 page 3)
(5) Schedule 12 page 1
(6) Schedule 13 pages 1 & 2
(7) Schedule 10 page 1
(8) Schedule 13 page 2
(9) Schedule 14 page 2

PECO Energy Company
Capitalization and Financial Statistics
2012-2016, Inclusive

	2016	2015	2014	2013	2012	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 6,179.0	$ 6,000.0	$ 5,551.0	$ 5,446.0	$ 5,200.0	
Short-Term Debt	$ -	$ -	$ -	$ -	$ 210.0	
Total Capital	$ 6,179.0	$ 6,000.0	$ 5,551.0	$ 5,446.0	$ 5,410.0	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	44.7%	46.1%	43.8%	43.7%	41.0%	43.9%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	1.7%	0.3%
Common Equity (1)	55.3%	53.9%	56.2%	56.3%	57.3%	55.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	44.7%	46.1%	43.8%	43.7%	43.3%	44.3%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	1.6%	0.3%
Common Equity (1)	55.3%	53.9%	56.2%	56.3%	55.1%	55.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	13.2%	11.9%	11.4%	12.8%	12.7%	12.4%
Operating Ratio (2)	76.4%	79.2%	81.5%	78.3%	79.9%	79.1%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	5.66 x	5.49 x	5.05 x	5.76 x	5.06 x	5.40 x
Post-tax: All Interest Charges	4.48 x	4.26 x	4.06 x	4.38 x	4.05 x	4.25 x
Overall Coverage: All Int. & Pfd. Div.	4.48 x	4.26 x	4.06 x	4.13 x	3.92 x	4.17 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	5.57 x	5.43 x	4.98 x	5.71 x	5.02 x	5.34 x
Post-tax: All Interest Charges	4.39 x	4.20 x	3.99 x	4.32 x	4.00 x	4.18 x
Overall Coverage: All Int. & Pfd. Div.	4.39 x	4.20 x	3.99 x	4.08 x	3.88 x	4.11 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	2.5%	1.9%	2.3%	1.5%	1.6%	2.0%
Effective Income Tax Rate	25.4%	27.4%	24.5%	29.1%	25.0%	26.3%
Internal Cash Generation/Construction (4)	83.7%	86.4%	67.8%	77.8%	97.9%	82.7%
Gross Cash Flow/ Avg. Total Debt (5)	30.8%	30.7%	31.9%	31.8%	31.8%	31.4%
Gross Cash Flow Interest Coverage (6)	7.58 x	7.69 x	7.50 x	7.23 x	6.98 x	7.40 x
Common Dividend Coverage (7)	3.07 x	2.86 x	2.40 x	2.26 x	2.20 x	2.56 x

See Page 2 for Notes.

PECO Energy Company
Capitalization and Financial Statistics
2012-2016, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(2) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(6) Gross Cash Flow plus interest charges divided by interest charges.
(7) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Utility COMPUSTAT

Electric Group
Capitalization and Financial Statistics [1]
2012-2016, Inclusive

	2016	2015	2014 (Millions of Dollars)	2013	2012	Average
Amount of Capital Employed						
Permanent Capital	$ 41,179.4	$ 38,011.3	$ 36,288.8	$ 33,192.4	$ 31,899.3	
Short-Term Debt	$ 1,367.7	$ 1,430.2	$ 1,191.3	$ 1,050.7	$ 963.3	
Total Capital	$ 42,547.1	$ 39,441.5	$ 37,480.1	$ 34,243.1	$ 32,862.6	
Market-Based Financial Ratios						
Price-Earnings Multiple	20 x	19 x	24 x	20 x	26 x	22 x
Market/Book Ratio	178.0%	167.2%	176.7%	164.8%	163.1%	170.0%
Dividend Yield	3.9%	3.5%	3.8%	4.3%	4.5%	4.0%
Dividend Payout Ratio	76.6%	60.0%	93.3%	82.9%	114.2%	85.4%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	52.8%	49.9%	49.1%	52.3%	52.2%	51.2%
Preferred Stock	1.0%	0.7%	0.6%	0.3%	0.3%	0.6%
Common Equity [2]	46.2%	49.4%	50.4%	47.5%	47.5%	48.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	54.2%	51.6%	50.4%	53.9%	53.7%	52.8%
Preferred Stock	1.0%	0.7%	0.6%	0.2%	0.3%	0.5%
Common Equity [2]	44.9%	47.8%	49.0%	45.8%	46.0%	46.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.0%	9.2%	8.5%	8.7%	8.2%	8.7%
Operating Ratio [3]	75.5%	76.6%	79.3%	78.2%	79.4%	77.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.85 x	3.89 x	3.65 x	3.52 x	3.23 x	3.63 x
Post-tax: All Interest Charges	2.92 x	2.95 x	2.72 x	2.67 x	2.49 x	2.75 x
Overall Coverage: All Int. & Pfd. Div.	2.92 x	2.95 x	2.72 x	2.67 x	2.49 x	2.75 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.76 x	3.82 x	3.59 x	3.47 x	3.16 x	3.56 x
Post-tax: All Interest Charges	2.83 x	2.87 x	2.66 x	2.61 x	2.42 x	2.68 x
Overall Coverage: All Int. & Pfd. Div.	2.83 x	2.87 x	2.66 x	2.61 x	2.42 x	2.68 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	5.0%	5.8%	8.4%	4.8%	5.7%	5.9%
Effective Income Tax Rate	32.8%	30.6%	27.3%	32.1%	32.8%	31.1%
Internal Cash Generation/Construction [5]	79.1%	81.3%	92.8%	80.6%	72.6%	81.3%
Gross Cash Flow/ Avg. Total Debt [6]	22.2%	22.5%	25.2%	20.6%	22.4%	22.6%
Gross Cash Flow Interest Coverage [7]	6.00 x	5.78 x	5.79 x	5.42 x	6.31 x	5.86 x
Common Dividend Coverage [8]	4.27 x	4.13 x	4.33 x	3.70 x	3.55 x	4.00 x

See Page 2 for Notes.

Electric Group
Capitalization and Financial Statistics
2012-2016, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.

(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.

(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Gross Cash Flow plus interest charges divided by interest charges.

(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Electric Group includes companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, and (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
AGR	Avangrid, Inc.	Baa1	BBB+	NYSE	NR	NMF
ED	Consol. Edison	A3	A-	NYSE	B+	0.50
D	Dominion Energy	Baa2	BBB+	NYSE	B	0.65
DUK	Duke Energy	Baa1	A-	NYSE	B	0.60
ES	Eversource Energy	Baa1	A	NYSE	A	0.65
EXC	Exelon Corp.	Baa2	BBB	NYSE	B	0.70
FE	FirstEnergy Corp.	Baa3	BBB-	NYSE	B	0.70
NEE	NextEra Energy	Baa1	A-	NYSE	A	0.65
PPL	PPL Corp.	Baa2	A-	NYSE	B	0.75
PEG	Public Serv. Enterprise	Baa1	BBB+	NYSE	B+	0.70
	Average	Baa1	BBB+		B+	0.66

Source of Information: Standard & Poor's Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2012-2016, Inclusive

	2016	2015	2014 (Millions of Dollars)	2013	2012	Average
Amount of Capital Employed						
Permanent Capital	$ 31,133.4	$ 28,468.3	$ 27,468.3	$ 25,958.6	$ 25,040.3	
Short-Term Debt	$ 1,113.4	$ 930.9	$ 963.9	$ 764.3	$ 659.0	
Total Capital	$ 32,246.8	$ 29,399.2	$ 28,432.2	$ 26,722.9	$ 25,699.3	
Market-Based Financial Ratios						
Price-Earnings Multiple	21 x	20 x	20 x	19 x	16 x	19 x
Market/Book Ratio	191.5%	179.3%	179.1%	164.4%	155.6%	174.0%
Dividend Yield	3.6%	3.7%	3.6%	3.9%	4.1%	3.8%
Dividend Payout Ratio	75.0%	70.0%	73.2%	73.3%	64.2%	71.1%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.7%	54.9%	53.3%	53.3%	53.7%	54.4%
Preferred Stock	1.8%	1.5%	1.3%	1.1%	1.0%	1.3%
Common Equity [2]	41.5%	43.6%	45.4%	45.7%	45.3%	44.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.3%	56.3%	55.0%	54.7%	54.9%	55.8%
Preferred Stock	1.8%	1.5%	1.3%	1.0%	1.0%	1.3%
Common Equity [2]	39.9%	42.2%	43.7%	44.3%	44.2%	42.9%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	9.0%	9.2%	9.6%	9.0%	9.3%	9.2%
Operating Ratio [3]	78.8%	80.4%	81.2%	80.7%	80.7%	80.4%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.15 x	3.41 x	3.56 x	3.22 x	2.90 x	3.25 x
Post-tax: All Interest Charges	2.53 x	2.65 x	2.71 x	2.48 x	2.35 x	2.54 x
Overall Coverage: All Int. & Pfd. Div.	2.50 x	2.62 x	2.67 x	2.45 x	2.31 x	2.51 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.05 x	3.31 x	3.46 x	3.13 x	2.80 x	3.15 x
Post-tax: All Interest Charges	2.43 x	2.55 x	2.62 x	2.39 x	2.25 x	2.45 x
Overall Coverage: All Int. & Pfd. Div.	2.40 x	2.52 x	2.58 x	2.36 x	2.21 x	2.41 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	6.4%	6.0%	7.1%	6.4%	7.0%	6.6%
Effective Income Tax Rate	28.1%	31.5%	28.6%	33.2%	30.7%	30.4%
Internal Cash Generation/Construction [5]	78.7%	70.6%	88.7%	83.2%	76.5%	79.5%
Gross Cash Flow/ Avg. Total Debt [6]	20.7%	20.0%	22.8%	22.4%	21.8%	21.5%
Gross Cash Flow Interest Coverage [7]	5.54 x	5.39 x	5.66 x	5.46 x	5.44 x	5.50 x
Common Dividend Coverage [8]	5.41 x	4.23 x	4.80 x	4.41 x	4.31 x	4.63 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2012-2016, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating (1) Moody's	S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
AGL Resources Inc.	GAS	A2	BBB+	NYSE	A	0.60
Ameren Corporation	AEE	Baa1	BBB+	NYSE	B	0.75
American Electric Power	AEP	Baa1	BBB	NYSE	B	0.70
CMS Energy	CMS	A3	BBB	NYSE	B	0.75
CenterPoint Energy	CNP	A3	A-	NYSE	B	0.85
Consolidated Edison	ED	A2	A-	NYSE	B+	0.60
DTE Energy Co.	DTE	A2	BBB+	NYSE	B+	0.75
Dominion Resources	D	A2	A-	NYSE	B+	0.70
Duke Energy	DUK	A1	BBB+	NYSE	B	0.65
Edison Int'l	EIX	A2	BBB+	NYSE	B	0.70
Entergy Corp.	ETR	Baa1	BBB	NYSE	A	0.70
EQT Corp.	EQT	Baa3	BBB	NYSE	B+	1.20
Exelon Corp.	EXC	A2	BBB	NYSE	B+	0.70
Eversource	NU	Baa1	A-	NYSE	B	0.75
FirstEnergy Corp.	FE	Baa2	BBB-	NYSE	B+	0.70
NextEra Energy Inc.	NEE	A1	A-	NYSE	A	0.75
NiSource Inc.	NI	Baa1	BBB-	NYSE	B	NMF
NRG Energy Inc.	NRG	Ba3	BB-	NYSE	B	1.00
ONEOK, Inc.	OKE	Baa3	BB+	NYSE	A-	0.85
PG&E Corp.	PCG	A3	BBB	NYSE	B	0.65
PPL Corp.	PPL	Baa1	BBB	NYSE	B+	0.70
Pinnacle West Capital	PNW	A3	A-	NYSE	B	0.75
Public Serv. Enterprise Inc.	PEG	A2	BBB+	NYSE	B+	0.75
SCANA Corp.	SCG	Baa2	BBB+	NYSE	A-	0.75
Sempra Energy	SRE	A1	A	NYSE	B+	0.80
Southern Co.	SO	A3	A	NYSE	A-	0.60
TECO Energy	TE	A2	BBB+	NYSE	B	0.85
Wisconsin Energy Corp.	WEC	A1	A-	NYSE	A	0.70
Xcel Energy Inc	XEL	A2	A-	NYSE	B+	0.65
Average for S&P Utilities		A3	BBB+		B+	0.75

Note: (1) Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

PECO Energy Company

Capitalization and Related Capital Structure Ratios

Actual at December 31,2017 and Estimated at December 31, 2018 and December 31, 2019

	Actual at December 31, 2017			Estimated at December 31, 2018			Estimated at December 31, 2019		
		Capital Structure Ratios			Capital Structure Ratios			Capital Structure Ratios	
	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt
Long-Term Debt [1]	$ 3,096,205	46.41%	46.41%	$ 3,298,828 [2]	46.60%	46.60%	$ 3,551,422 [2]	46.61%	46.61%
Common Equity									
Common Stock	1,423,004			1,423,004			1,423,004		
Other Paid-In Capital	1,066,114			1,141,114 [4]			1,291,202 [5]		
Retained Earnings [3]	1,086,662			1,216,116 [5]			1,354,042 [4]		
Total Common Equity	3,575,780	53.59%	53.59%	3,780,234	53.40%	53.40%	4,068,248	53.39%	53.39%
Total Permanent Capital	6,671,985	100.00%	100.00%	7,079,062	100.00%	100.00%	7,619,670	100.00%	100.00%
Short-Term Debt	-	0.00%		-	0.00%		-	0.00%	
Total Capital Employed	$ 6,671,985	100.00%		$ 7,079,062	100.00%		$ 7,619,670	100.00%	

Notes:

[1] Includes current portion of long-term debt.

[2] Reflects change in long-term debt consisting of:

	2018	2019
Maturity	$ (500,000)	
New issue	325,000	$ 250,000
New issue	325,000	
New issue	50,000	
Change in Adjustment for Tenders and Calls	$ 2,623	$ 2,594

[3] Excludes Accumulated Other Comprehensive Income of $1.436 million.

	2018	2019
[4] Equity Infusions	$ 75,000	150,088
[5] Reflects change in retained earnings consisting of:		
Net income	$ 435,454	$ 460,926
Common Dividends	$ (306,000)	$ (323,000)

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2017

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
5.35%	03/01/18	$ 500,000,000	16.08%	5.47%	0.88%
1.70%	09/15/21	300,000,000	9.65%	1.86%	0.18%
2.375%	09/15/22	350,000,000	11.26%	2.47%	0.28%
3.150%	10/15/25	350,000,000	11.26%	3.29%	0.37%
5.90%	05/01/34	75,000,000	2.41%	6.00%	0.14%
5.95%	10/01/36	300,000,000	9.65%	6.04%	0.58%
5.70%	03/15/37	175,000,000	5.63%	5.81%	0.33%
4.80%	10/15/43	250,000,000	8.04%	4.89%	0.39%
4.15%	10/01/44	300,000,000	9.65%	4.23%	0.41%
3.70%	09/15/47	325,000,000	10.45%	3.75%	0.39%
		2,925,000,000			
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	2.59%	7.46%	0.19%
6.50%	04/06/28	805,206	0.03%	6.50%	0.00%
5.75%	06/15/33	103,092,784	3.32%	5.88%	0.19%
		184,418,609			
		3,109,418,609	100.00%		4.33%
Adjustment for Tenders and Calls		(13,214,000)			
Long-Term Debt		$ 3,096,204,609			
Annualized Cost		$ 134,637,826			
Adjustment for Tenders and Calls on Reacquired Debt		2,621,000			
Total Cost		$ 137,258,826			4.43%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2018

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate
First and Refunding Mortgage Bonds					
1.70%	09/15/21	$ 300,000,000	9.07%	1.86%	0.17%
2.375%	09/15/22	350,000,000	10.58%	2.47%	0.26%
3.150%	10/15/25	350,000,000	10.58%	3.29%	0.35%
5.90%	05/01/34	75,000,000	2.27%	6.00%	0.14%
5.95%	10/01/36	300,000,000	9.07%	6.04%	0.55%
5.70%	03/15/37	175,000,000	5.29%	5.81%	0.31%
4.80%	10/15/43	250,000,000	7.55%	4.89%	0.37%
4.15%	10/01/44	300,000,000	9.07%	4.23%	0.38%
3.70%	09/15/47	325,000,000	9.82%	3.75%	0.37%
3.90%	03/01/48	325,000,000	9.82%	3.99%	0.39%
4.03%	09/01/48	325,000,000	9.82%	4.08%	0.40%
2.00%	09/01/23	50,000,000	1.51%	2.24%	0.03%
		3,125,000,000			
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	2.43%	7.46%	0.18%
6.50%	04/06/28	805,206	0.02%	6.50%	0.00%
5.75%	06/15/33	103,092,784	3.12%	5.88%	0.18%
		184,418,609			
		3,309,418,609	100.00%		4.08%
Adjustment for Tenders and Calls		(10,591,000)			
Long-Term Debt		$ 3,298,827,609			
Annualized Cost		$ 135,024,279			
Adjustment for Tenders and Calls on Reacquired Debt		2,621,000			
Total Cost		$ 137,645,279			4.17%

Notes: (1) As calculated on page 4 of this schedule.

Source of Information: Company provided data

PECO Energy Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2019

Series	Date of Maturity	Principal Amount Outstanding	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
First and Refunding Mortgage Bonds					
1.70%	09/15/21	$ 300,000,000	8.43%	1.86%	0.16%
2.375%	09/15/22	350,000,000	9.83%	2.47%	0.24%
3.150%	10/15/25	350,000,000	9.83%	3.29%	0.32%
5.90%	05/01/34	75,000,000	2.11%	6.00%	0.13%
5.95%	10/01/36	300,000,000	8.43%	6.04%	0.51%
5.70%	03/15/37	175,000,000	4.92%	5.81%	0.29%
4.80%	10/15/43	250,000,000	7.02%	4.89%	0.34%
4.15%	10/01/44	300,000,000	8.43%	4.23%	0.36%
3.70%	09/15/47	325,000,000	9.13%	3.75%	0.34%
3.90%	03/01/48	325,000,000	9.13%	3.99%	0.36%
4.03%	03/01/48	325,000,000	9.13%	4.08%	0.37%
2.00%	03/01/48	50,000,000	1.41%	2.24%	0.03%
4.08%	09/01/49	250,000,000	7.02%	4.15%	0.29%
		3,375,000,000			
Trust Preferred Capital Securities					
7.38%	04/06/28	80,520,619	2.26%	7.46%	0.17%
6.50%	04/06/28	805,206	0.02%	6.50%	0.00%
5.75%	06/15/33	103,092,784	2.90%	5.88%	0.17%
		184,418,609			
		3,559,418,609	100.00%		4.08%
Adjustment for Tenders and Calls		(7,997,000)			
Long-Term Debt		$ 3,551,421,609			
Annualized Cost		$ 145,224,279			
Adjustment for Tenders and Calls on Reacquired Debt		2,557,000			
Total Cost		$ 147,781,279			4.16%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

PECO Energy Company

Calculation of the Effective Cost of Long-Term Debt by Series

Series		Date of Issue	Date of Maturity	Average Term in Years [1]	Principal Amount Issued	Premium/ Discount & Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [2]
First and Refunding Mortgage Bonds									
5.35%		03/03/08	03/01/18	10	$ 500,000,000	$ 4,449,692	$ 495,550,308	99.11%	5.47%
1.70%		09/21/16	09/15/21	5	$ 300,000,000	$ 2,348,606	$ 297,651,394	99.22%	1.86%
2.375%		09/17/12	09/15/22	10	350,000,000	3,054,240	346,945,760	99.13%	2.47%
3.15%		10/05/15	10/15/25	10	350,000,000	4,156,454	345,843,546	98.81%	3.29%
5.90%		04/23/04	05/01/34	30	75,000,000	1,024,692	73,975,308	98.63%	6.00%
5.95%		09/25/06	10/01/36	30	300,000,000	3,862,236	296,137,764	98.71%	6.04%
5.70%		03/19/07	03/15/37	30	175,000,000	2,672,126	172,327,874	98.47%	5.81%
4.80%		09/23/13	10/15/43	30	250,000,000	3,475,050	246,524,950	98.61%	4.89%
4.15%		09/15/14	10/01/44	30	300,000,000	4,211,731	295,788,269	98.60%	4.23%
3.70%		09/18/17	09/15/47	30	325,000,000	3,093,071	321,906,929	99.05%	3.75%
3.90%		02/23/18	03/01/48	30	325,000,000	5,042,750	319,957,250	98.45%	3.99%
4.03%	(3)	09/01/18	09/01/48	30	325,000,000	3,000,000	322,000,000	99.08%	4.08%
2.00%	(3)	09/01/18	09/01/23	5	50,000,000	575,000	49,425,000	98.85%	2.24%
4.08%	(3)	09/01/19	09/01/49	30	250,000,000	3,000,000	247,000,000	98.80%	4.15%
Trust Preferred Capital Securities									
7.38%		04/06/98	04/06/28	30	80,520,619	760,181	79,760,438	99.06%	7.46%
6.50%	(4)	04/06/98	04/06/28	30	805,206	-	805,206	100.00%	6.50%
5.75%		06/24/03	06/15/33	30	103,092,784	1,934,015	101,158,769	98.12%	5.88%

Notes: (1) Determined by taking into account the effect of the annual sinking fund requirements which are met by the retirement of bonds which reduce the term of each issue.
(2) The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.
0 Estimated.
(4) Variable rate at Prime Rate of 4.50% plus two-percentage points.

Source of Information: Company provided data

Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending December 2017

Company	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	12-Month Average	6-Month Average	3-Month Average
AVANGRID, Inc (AGR)	4.48%	3.99%	4.05%	4.00%	3.84%	3.92%	3.83%	3.57%	3.65%	3.36%	3.28%	3.42%			
Consolidated Edison Inc (ED)	3.74%	3.59%	3.57%	3.51%	3.34%	3.43%	3.35%	3.28%	3.44%	3.23%	3.10%	3.26%			
Dominion Energy Inc (D)	3.99%	3.93%	3.91%	3.93%	3.74%	3.95%	3.94%	3.83%	3.94%	3.82%	3.66%	3.81%			
Duke Energy Corporation (DUK)	4.39%	4.15%	4.19%	4.18%	4.00%	4.11%	4.22%	4.08%	4.26%	4.07%	4.00%	4.25%			
Eversource Energy (ES)	3.45%	3.26%	3.24%	3.22%	3.06%	3.14%	3.14%	3.04%	3.15%	3.04%	2.95%	3.01%			
Exelon Corp (EXC)	3.68%	3.57%	3.66%	3.81%	3.61%	3.65%	3.44%	3.47%	3.49%	3.28%	3.15%	3.34%			
FirstEnergy Corp (FE)	4.81%	4.45%	4.56%	4.86%	4.94%	4.98%	4.56%	4.43%	4.71%	4.42%	4.23%	4.74%			
NextEra Energy Inc (NEE)	3.20%	3.00%	3.07%	2.96%	2.78%	2.81%	2.70%	2.61%	2.69%	2.55%	2.49%	2.52%			
PPL Corp (PPL)	4.57%	4.33%	4.24%	4.17%	4.00%	4.10%	4.15%	4.06%	4.17%	4.23%	4.35%	5.12%			
Public Service Enterprise Group Inc (PEG)	3.91%	3.77%	3.89%	3.93%	3.86%	4.01%	3.85%	3.70%	3.73%	3.51%	3.27%	3.35%			
Average	**4.02%**	**3.80%**	**3.84%**	**3.86%**	**3.72%**	**3.81%**	**3.72%**	**3.61%**	**3.72%**	**3.55%**	**3.45%**	**3.68%**	**3.73%**	**3.62%**	**3.56%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: http://performance.morningstar.com/stock/performance-return
http://www.snl.com/interactivex/dividends

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0
	3.62%	1.028750	3.73%
Discrete	D_0/P_0	Adj.	D_1/P_0
	3.62%	1.035686	3.75%
Quarterly	D_0/P_0	Adj.	D_1/P_0
	0.9054%	1.014075	3.72%
Average			3.73%
Growth rate			5.75%
K			9.48%

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

	Earnings per Share		Dividends per Share		Book Value per Share		Cash Flow per Share	
	Value Line		Value Line		Value Line		Value Line	
Electric Group	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year	5 Year	10 Year
AVANGRID, Inc.	-	-	-	-	-	-	-	-
Consol. Edison	2.50%	3.50%	2.00%	1.50%	3.50%	4.00%	4.50%	4.50%
Dominion Energy	3.00%	5.00%	7.00%	7.00%	1.50%	2.50%	4.00%	3.50%
Duke Energy	0.50%	3.50%	2.50%	-	3.00%	-0.50%	2.50%	1.50%
Eversource Energy	6.00%	12.00%	10.50%	9.50%	8.50%	6.00%	-0.50%	0.50%
Exelon Corp.	-11.50%	-4.00%	-10.00%	-2.00%	6.00%	7.00%	-3.00%	1.00%
FirstEnergy Corp.	-10.00%	-6.00%	-8.00%	-2.50%	-3.50%	-1.00%	-5.50%	-2.50%
NextEra Energy	5.00%	8.00%	9.00%	8.50%	7.50%	8.00%	6.50%	7.50%
PPL Corp.	4.50%	2.00%	1.50%	4.50%	-	3.00%	1.50%	1.00%
Public Serv. Enterprise	-0.50%	6.00%	3.00%	3.50%	6.00%	7.50%	2.00%	5.00%
Average	-0.06%	3.33%	1.94%	3.75%	4.06%	4.06%	1.33%	2.44%

Source of Information: Value Line Investment Survey November 17, 2017

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

					Value Line				
Electric Group	**I/B/E/S First Call**	**Zacks**	**Morningstar**	**SNL**	**Earnings Per Share**	**Dividends Per Share**	**Book Value Per Share**	**Cash Flow Per Share**	**Percent Retained to Common Equity**
AVANGRID, Inc.	8.40%	8.30%	-	8.50%	NMF	NMF	NMF	NMF	1.50%
Consol. Edison	3.23%	2.00%	4.10%	3.88%	2.50%	3.00%	3.50%	4.00%	2.50%
Dominion Energy	3.64%	5.60%	7.00%	4.97%	6.50%	9.00%	2.50%	7.50%	2.00%
Duke Energy	3.23%	4.00%	9.00%	4.53%	4.50%	4.50%	1.50%	5.00%	2.00%
Eversource Energy	5.92%	5.90%	6.20%	6.00%	6.50%	6.00%	4.00%	7.00%	4.00%
Exelon Corp.	0.28%	4.30%	6.70%	3.00%	8.50%	5.50%	4.00%	5.50%	4.50%
FirstEnergy Corp.		NA	1.90%	2.00%	12.00%	2.00%	Nil	3.00%	7.00%
NextEra Energy	8.04%	7.40%	7.30%	7.39%	7.00%	9.50%	5.00%	5.50%	5.00%
PPL Corp.		7.00%		4.50%	NMF	3.00%	NMF	NMF	4.50%
Public Serv. Enterprise	1.38%	2.70%	3.80%	3.00%	1.00%	5.00%	3.00%	3.50%	3.50%
Average	4.27%	5.24%	5.75%	4.78%	6.06%	5.28%	3.36%	5.13%	3.65%

Note: Negative growth rates removed for FirstEnergy of -7.29% by I/B/E/S First Call and for PPL Corp. of -0.03% by I/B/E/S First Call and -0.10% by Morningstar.

Source of Information : Yahoo Finance, December 20, 2017
Zacks, December 20, 2017
Morningstar, December 20, 2017
SNL, December 22, 2017
Value Line Investment Survey November 17, 2017

Electric Group

Financial Risk Adjustment

	AVANGRID Inc (AGR)	Consolidated Edison Inc (ED)	Dominion Resources Inc (D)	Duke Energy Corporation (DUK)	Eversource Energy (ES)	Exelon Corp(EXC)	FirstEnergy Corp (FE)	NextEra Energy Inc (NEE)	PPL Corp (PPL)	Public Service Enterprise Group Inc (PEG)	Average
Fiscal Year	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	
Capitalization at Fair Values											
Debt(D)	5,204,000	16,093,000	33,584,000	49,161,000	9,980,500	35,480,000	19,829,000	31,623,000	21,355,000	12,003,000	23,431,250
Preferred(P)	0	0	0	0	158,300	0	0	0	0	0	15,830
Equity(E)	11,704,660	20,777,760	48,098,520	54,334,000	17,501,603	32,794,004	13,699,400	55,907,280	23,144,841	22,153,529	30,011,560
Total	16,908,660	36,870,760	81,682,520	103,495,000	27,640,403	68,274,004	33,528,400	87,530,280	44,499,841	34,156,529	53,458,640
Capital Structure Ratios											
Debt(D)	30.78%	43.65%	41.12%	47.50%	36.11%	51.97%	59.14%	36.13%	47.99%	35.14%	42.95%
Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.57%	0.00%	0.00%	0.00%	0.00%	0.00%	0.06%
Equity(E)	69.22%	56.35%	58.88%	52.50%	63.32%	48.03%	40.86%	63.87%	52.01%	64.86%	56.99%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Common Stock											
Issued		305,000.000		700,000.000			442,344.218	468,000.000	679,731.000		
Treasury		23,000.000		0.000			0.000	0.000	0.000		
Outstanding	308,993.149	282,000.000	628,000.000	700,000.000	316,885.808	924,035.059	442,344.218	468,000.000	679,731.000	504,866.212	
Market Price	$37.88	$73.68	$76.59	$77.62	$55.23	$35.49	$30.97	$119.46	$34.05	$43.88	
Capitalization at Carrying Amounts											
Debt(D)	4,859,000	14,774,000	31,940,000	47,895,000	9,603,200	34,646,000	19,885,000	30,418,000	18,326,000	11,395,000	22,374,120
Preferred(P)	0	0	0	0	155,600	0	0	0	0	0	15,560
Equity(E)	15,109,000	14,298,000	14,605,000	41,033,000	10,711,734	25,837,000	6,241,000	24,341,000	9,899,000	13,130,000	17,520,473
Total	19,968,000	29,072,000	46,545,000	88,928,000	20,470,534	60,483,000	26,126,000	54,759,000	28,225,000	24,525,000	39,910,153
Capital Structure Ratios											
Debt(D)	24.33%	50.82%	68.62%	53.86%	46.91%	57.28%	76.11%	55.55%	64.93%	46.46%	54.49%
Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%
Equity(E)	75.67%	49.18%	31.38%	46.14%	52.33%	42.72%	23.89%	44.45%	35.07%	53.54%	45.44%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%
Betas Value Line	NMF	0.50	0.65	0.60	0.65	0.70	0.70	0.65	0.75	0.70	0.66

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.66	=	Bu	[1+	(1-0.21)	0.7536	+	0.0011	]
	0.66	=	Bu	[1+	0.79	0.7536	+	0.0011	]
	0.66	=	Bu	1.5964					
	0.41	=	Bu						

Hamada	Bl	=	0.41	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.41	[1+	0.79	1.1992	+	0.0018	]
	Bl	=	0.41	1.9492					
	Bl	=	0.80						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	) - (	ku	-	d	)	P	/	E
	7.39%	=	9.48%	-	(((	7.39%	-	3.88%	)	0.79	)	42.95%	/	56.99%	) - (	7.39%	-	5.68%	)	0.06%	/	56.99%
	7.39%	=	9.48%	-	(((	3.51%			)	0.79	)	0.7536			) - (	1.71%			)	0.0011		
	7.39%	=	9.48%	-	((	2.77%					)	0.7536			) - (	1.71%			)	0.0011		
	7.39%	=	9.48%	-		2.09%									-	0.00%						

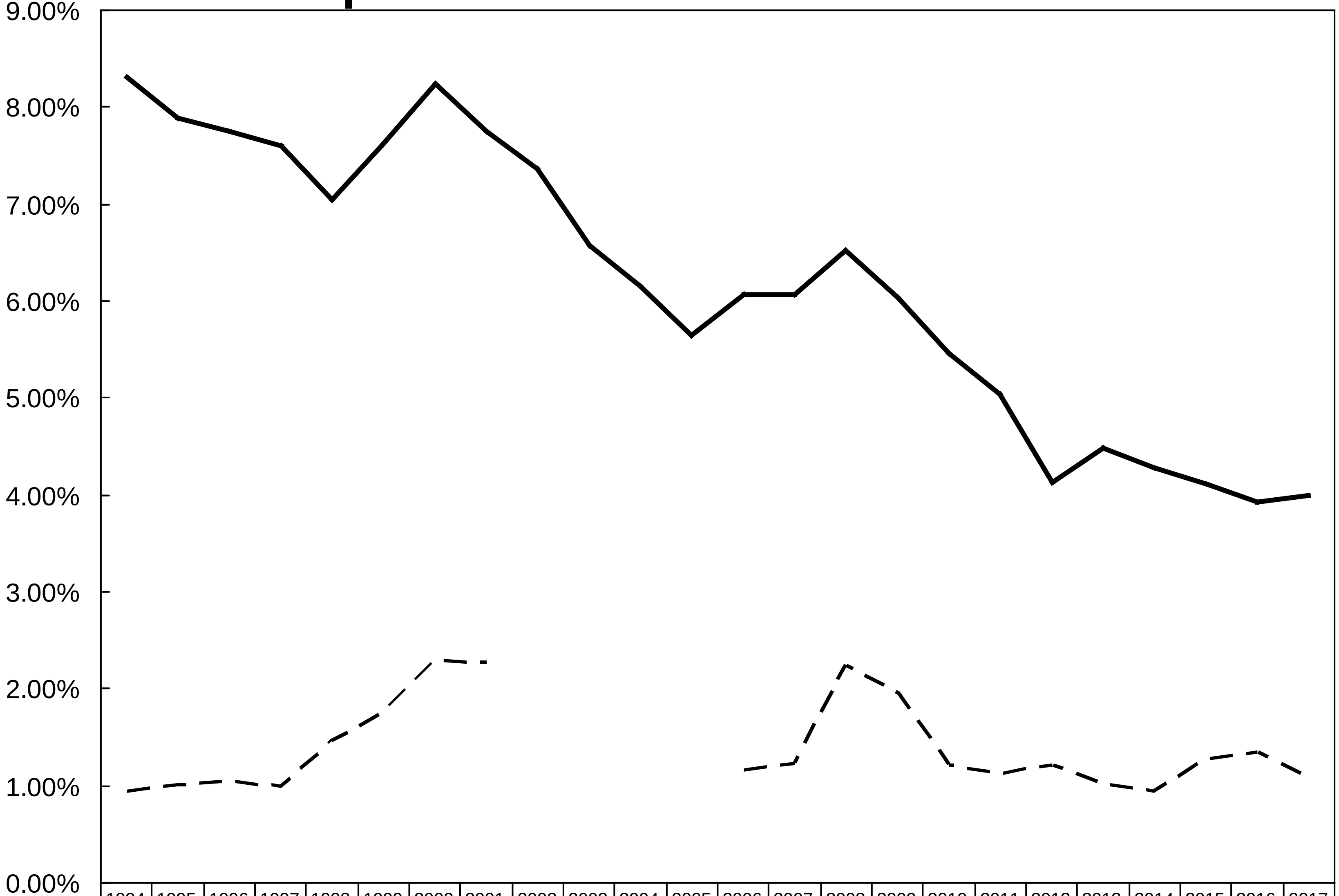
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	) + (	ku	-	d	)	P	/	E
	10.71%	=	7.39%	+	(((	7.39%	-	3.88%	)	0.79	)	54.49%	/	45.44%	) + (	7.39%	-	5.68%	)	0.08%	/	45.44%
	10.71%	=	7.39%	+	(((	3.51%			)	0.79	)	1.1992			) + (	1.71%			)	0.0018		
	10.71%	=	7.39%	+	((	2.77%					)	1.1992			) + (	1.71%			)	0.0018		
	10.71%	=	7.39%	+		3.32%									+	0.00%						

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2012-2016
and the Twelve Months Ended December 2017

Years	Aa Rated	A Rated	Baa Rated	Average
2012	3.83%	4.13%	4.86%	4.27%
2013	4.24%	4.48%	4.98%	4.57%
2014	4.19%	4.28%	4.80%	4.42%
2015	4.00%	4.12%	5.03%	4.38%
2016	3.73%	3.93%	4.68%	4.11%
Five-Year Average	4.00%	4.19%	4.87%	4.35%
Months				
Jan-17	3.96%	4.14%	4.62%	4.24%
Feb-17	3.99%	4.18%	4.58%	4.25%
Mar-17	4.04%	4.23%	4.62%	4.30%
Apr-17	3.93%	4.12%	4.51%	4.19%
May-17	3.94%	4.12%	4.50%	4.19%
Jun-17	3.77%	3.94%	4.32%	4.01%
Jul-17	3.82%	3.99%	4.36%	4.06%
Aug-17	3.67%	3.86%	4.23%	3.92%
Sep-17	3.70%	3.87%	4.24%	3.93%
Oct-17	3.74%	3.91%	4.26%	3.97%
Nov-17	3.65%	3.83%	4.16%	3.88%
Dec-17	3.62%	3.79%	4.14%	3.85%
Twelve-Month Average	3.82%	4.00%	4.38%	4.07%
Six-Month Average	3.70%	3.88%	4.23%	3.94%
Three-Month Average	3.67%	3.84%	4.19%	3.90%

Source: Mergent Bond Record

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%	6.07%	6.53%	6.04%	5.46%	5.04%	4.13%	4.48%	4.28%	4.12%	3.93%	4.00%
Spread vs. 30-year	0.94%	1.01%	1.04%	0.99%	1.46%	1.75%	2.30%	2.27%					1.16%	1.23%	2.25%	1.96%	1.21%	1.13%	1.21%	1.03%	0.94%	1.28%	1.34%	1.10%

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Average:			
12-months			1.10%
6-months			1.06%
3-months			1.03%

Common Equity Risk Premiums
Years 1926-2016

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	11.97%	4.89%	7.08%	2.96%
Average Across All Interest Rates	11.95%	6.31%	5.64%	5.07%
High Interest Rates	11.93%	7.75%	4.18%	7.22%

Source of Information: 2017 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2012-2016
and the Twelve Months Ended December 2017

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2012	0.17%	0.28%	0.38%	0.76%	1.22%	1.80%	2.54%	2.92%
2013	0.13%	0.31%	0.54%	1.17%	1.74%	2.35%	3.12%	3.45%
2014	0.12%	0.46%	0.90%	1.64%	2.14%	2.54%	3.07%	3.34%
2015	0.32%	0.69%	1.03%	1.53%	1.89%	2.14%	2.55%	2.84%
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
Five-Year Average	0.27%	0.52%	0.77%	1.29%	1.73%	2.13%	2.70%	3.03%
Months								
Jan-17	0.83%	1.21%	1.48%	1.92%	2.23%	2.43%	2.75%	3.02%
Feb-17	0.82%	1.20%	1.47%	1.90%	2.22%	2.42%	2.76%	3.03%
Mar-17	1.01%	1.31%	1.59%	2.01%	2.30%	2.48%	2.83%	3.08%
Apr-17	1.04%	1.24%	1.44%	1.82%	2.10%	2.30%	2.67%	2.94%
May-17	1.12%	1.30%	1.48%	1.84%	2.11%	2.30%	2.70%	2.96%
Jun-17	1.20%	1.34%	1.49%	1.77%	2.01%	2.19%	2.54%	2.80%
Jul-17	1.22%	1.37%	1.54%	1.87%	2.13%	2.32%	2.65%	2.88%
Aug-17	1.23%	1.34%	1.48%	1.78%	2.03%	2.21%	2.55%	2.80%
Sep-17	1.28%	1.38%	1.51%	1.80%	2.03%	2.20%	2.53%	2.78%
Oct-17	1.40%	1.55%	1.68%	1.98%	2.20%	2.36%	2.65%	2.88%
Nov-17	1.56%	1.70%	1.81%	2.05%	2.23%	2.35%	2.60%	2.80%
Dec-17	1.70%	1.84%	1.96%	2.18%	2.32%	2.40%	2.60%	2.77%
Twelve-Month Average	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
Six-Month Average	1.40%	1.53%	1.66%	1.94%	2.16%	2.31%	2.60%	2.82%
Three-Month Average	1.55%	1.70%	1.82%	2.07%	2.25%	2.37%	2.62%	2.82%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated January 1, 2018

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2018	First	1.7%	1.9%	2.3%	2.6%	3.0%	3.8%	4.5%
2018	Second	1.9%	2.1%	2.4%	2.7%	3.1%	4.0%	4.7%
2018	Third	2.1%	2.2%	2.5%	2.8%	3.3%	4.2%	4.9%
2018	Fourth	2.3%	2.4%	2.7%	2.9%	3.4%	4.4%	5.1%
2019	First	2.5%	2.6%	2.8%	3.1%	3.5%	4.5%	5.2%
2019	Second	2.6%	2.7%	2.9%	3.2%	3.6%	4.6%	5.4%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
29-Dec-17	1.9%	+	5.74%	=	7.64%

DCF Result for the S&P 500 Composite

D/P	(1+.5g)	+	g	=	k
1.84%	(1.0495)	+	9.90%	=	11.83%

where:	Price (P)	at	31-Dec-17	=	2673.61
	Dividend (D)	for	3rd Qtr. '17	=	12.31
	Dividend (D)		annualized	=	49.24
	Growth (g)	by	Morningstar	=	9.90%

Summary

Value Line			
S&P 500			11.83%
Average			11.83%
Risk-free Rate of Return (Rf)			3.75%
Forecast Market Premium			8.08%
Historical Market Premium	(Rm)	(Rf)	
1926-2016 Arith. mean	11.96%	4.02%	7.94%
Average - Forecast/Historical			8.01%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach

Using Non-Utility Companies with
Timeliness of 1, 2, 3, 4 & 5; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++, A, A+ & A++;
Price Stability of 85 to 100; Betas of .50 to .75; and Technical Rank of 2, 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Altria Group Inc	Tobacco	3	2	B+	100	0.65	3
Campbell Soup Co	Food Processing	4	2	B++	95	0.70	3
Capitol Federal Financial Inc	Thrift	5	2	B+	100	0.75	3
CBOE Holdings Inc	Brokers & Exchanges	2	2	B++	85	0.70	3
Church and Dwight Co Inc	Household Products	2	1	A+	100	0.75	5
Clorox Co	Household Products	2	2	B++	100	0.65	3
CME Group Inc	Brokers & Exchanges	1	2	A	85	0.75	2
Coca Cola Company	Beverage	4	1	A++	100	0.70	2
Dr Pepper Snapple Group In	Beverage	4	2	A	100	0.75	4
Eli Lilly and Co	Drug	2	1	A++	90	0.75	2
Hershey Company	Food Processing	3	2	B++	95	0.75	3
Hormel Foods Corporation	Food Processing	4	2	A	85	0.75	3
JM Smucker Company	Food Processing	4	1	A++	95	0.70	5
Kellogg Company	Food Processing	3	1	A	100	0.75	5
Kimberly Clark Corp	Household Products	3	1	A++	95	0.75	4
Philip Morris International In	Tobacco	3	2	B++	95	0.75	3
Procter and Gamble Co	Household Products	3	1	A++	100	0.70	3
Sysco Corp	Retail/Wholesale Food	3	1	A+	95	0.75	3
Walmart Stores Inc	Retail Store	4	1	A++	95	0.70	3
Average		3	2	B+	95	0.72	3
Electric Group	Average	3	2	A	95	0.66	4

Source of Information: Value Line Investment Survey for Windows, January 2018

Comparable Earnings Approach

Five -Year Average Historical Earned Returns
for Years 2012-2016 and
Projected 3-5 Year Returns

Company	2012	2013	2014	2015	2016	Average	Projected 2020-22
Altria Group Inc	NMF	NMF	NMF	NMF	41.5%	41.5%	59.0%
Campbell Soup Co	87.2%	64.6%	49.5%	60.2%	59.9%	64.3%	29.5%
Capitol Federal Financial Inc	4.1%	4.2%	5.2%	5.5%	6.0%	5.0%	7.5%
CBOE Holdings Inc	65.8%	61.9%	75.9%	79.0%	58.4%	68.2%	12.5%
Church and Dwight Co Inc	17.0%	17.1%	19.7%	21.4%	23.5%	19.7%	19.0%
Clorox Co	-	NMF	NMF	NMF	NMF	-	69.0%
CME Group Inc	4.7%	4.6%	5.4%	6.1%	7.5%	5.7%	8.5%
Coca Cola Company	27.5%	28.3%	30.0%	34.4%	36.2%	31.3%	47.0%
Dr Pepper Snapple Group Inc	26.9%	26.5%	30.6%	35.0%	40.1%	31.8%	32.0%
Eli Lilly and Co	25.6%	25.5%	19.4%	25.1%	26.7%	24.5%	27.0%
Hershey Company	71.4%	52.6%	61.6%	91.2%	120.7%	79.5%	48.5%
Hormel Foods Corporation	17.7%	15.9%	16.7%	17.9%	20.0%	17.6%	18.5%
JM Smucker Company	11.4%	11.7%	7.8%	10.0%	11.0%	10.4%	11.5%
Kellogg Company	53.6%	38.9%	50.1%	59.1%	69.0%	54.1%	43.0%
Kimberly Clark Corp	35.1%	44.1%	202.5%	NMF	NMF	93.9%	NMF
Philip Morris International Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Procter and Gamble Co	17.7%	17.3%	17.5%	18.3%	18.0%	17.8%	22.0%
Sysco Corp	23.9%	19.1%	17.7%	20.9%	34.9%	23.3%	83.0%
Walmart Stores Inc	22.3%	21.9%	20.2%	18.2%	17.3%	20.0%	20.5%
Average						35.8%	32.8%
Average (excluding companies with values >20%)						11.7%	13.0%

Comparable Earnings Approach

Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

PECO ENERGY COMPANY
STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DOCKET NO. R-2018-3000164

DIRECT TESTIMONY

WITNESS: JIANG DING

SUBJECT: CLASS COST-OF-SERVICE STUDY

DATED: MARCH 29, 2018

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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. For example, in the Company's last base rate proceeding, I developed the COS study with PECO witness, Alan B. Cohn, and assisted with preparing all exhibits accompanying his cost-of-service testimony.

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

A. Yes. PECO Exhibits JD-1 to JD-10 were prepared and are described in detail in my testimony.

6. 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 ("COS study") that I performed, the methods and procedures employed to perform such study and the results produced by the COS study.

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 COS Study. Second, I introduce and discuss the COS study methodology. Third, I explain the development of the revenue requirement for each rate class. Fourth, I present the results of the COS study in detail and discuss the contents of the exhibits. Finally, I describe the analysis undertaken by the Company in accordance with the settlement of its 2015 base rate proceeding.

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

8. Q. What is the total revenue requirement you used to prepare PECO's COS study?

A. I used the total distribution revenue requirement for the fully projected future test year ("FPFTY") developed in PECO Exhibit BSY-1, which is sponsored by PECO witness Benjamin S. Yin and discussed in Mr. Yin's direct testimony (PECO St. No. 3). The total distribution revenue requirement for the FPFTY is $1,406 million (PECO Exhibit JD-1, line 64) excluding costs recovered under PECO's Generation Supply Adjustment ("GSA")[1] and Transmission Service Charge ("TSC")[2] and $2,241 million (PECO Exhibit JD-1, line 114) 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 COS study were also obtained from PECO Exhibit BSY-1.

9. Q. Please identify the exhibits that accompany your direct testimony.

A. The exhibits identified below accompany my testimony and are discussed in greater detail in Section IV of my testimony.

[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 LLC ("PJM") furnishes network transmission service to PECO pursuant to the PJM Open Access Transmission Tariff.

PECO Exhibit JD-1	Summary of Results
PECO Exhibit JD-2	Total Class Allocation - Revenue Requirement by Rate Class
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 GSA
PECO Exhibit JD-9	Development of Unbundled Cash Working Capital Rate for the TSC
PECO Exhibit JD-10	Calculation of Rate HT High Voltage Discount

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

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

1. The current tariff rates produce the net income by rate class shown on line 16 of PECO Exhibit JD-1,[3] which yields the rates of return on rate base shown on line 25 of that exhibit. The table below summarizes these results.

Rate Class	ROR	Ratio to Average ROR
R	5.65%	0.98
RH	4.50%	0.78
GS	6.63%	1.15
PD	6.46%	1.12
HT	6.03%	1.05

[3] Please note that the line numbering is continuous across pages 1-3 of PECO Exhibit JD-1. I will refer to the line numbers in PECO Exhibit JD-1 without page references.

EP	3.65%	0.63
SL	7.12%	1.24
Average	5.76%	

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 COS study. The results of the COS study 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 120 of page 3 of PECO Exhibit JD-1. The increases or (decreases) in revenue shown on line 120 are shown separately for Distribution base rates (line 70) and the working capital revenue requirement recovered in the TSC (line 95) and in the GSA (line 83) 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 by the direct testimony of Mark Kehl in PECO Statement No. 7.

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

11. Q. Briefly describe the purpose of a class COS study.

A. The purpose of a COS study 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 COS study, all of the utility's costs of providing service must be analyzed and assigned or allocated among the rate classes. The COS study is used, along with other factors, as discussed in more detail by Mr. Kehl, to design rates that fully recover the utility's costs.

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

A. The central element in performing a COS study 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 COS study captures all of the costs that each class imposes on the distribution system.

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

A. The rate classes included in the PECO COS study 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 COS study, all of 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. Please summarize the approach you used in preparing PECO's COS study.

A. As I previously explained, the most critical task in performing any COS study 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 firm delivery customers whenever those peaks occur, and
3. Assure that electricity is delivered to customers safely and reliably throughout the year.

The allocation methods used in a COS study 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 COS study I prepared was performed using the proprietary Electric Cost of Service Model ("Model") developed by Management

Applications Consulting, Inc., which employs a Microsoft Excel platform. The Model facilitates the preparation of the COS study, 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.

15. Q. Please describe the functions included in the COS study.

A. The COS study includes the following functions:

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

Transmission: The Transmission 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").[4] 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

[4] 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.

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.

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, 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.

16. Q. Please describe the classification step of a COS study.

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 non-coincident peak ("NCP") demands (i.e., the peak electricity demand of each rate class, not necessarily coincident with each other or with the system peak).

17. 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.

18. Q. Please describe the class allocation step of a COS study.

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.

19. 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.

20. Q. Can significant portions of a utility's assets and expenses generally be directly assigned in a COS study?

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.

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

A. External and internal allocation factors are typically used to perform a COS study 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 and customer counts for customer-related plant costs).

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

A. The total rate base amount employed in the PECO COS study is $4,846 million (PECO Exhibit JD-1, line 103) and is derived from PECO Exhibit BSY-1, page 1.

23. 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 COS study, I will refer to the following components of rate base:

- Intangible plant
- Distribution plant

- General plant
- Depreciation reserve
- Other rate base items

24. 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 number 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 upon a detailed study of the respective costs, as shown in PECO Exhibit JD-7 at page 3. 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. 14). 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. 4).

- 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"). The unrecovered cost of Automated Meter Reading ("AMR") meters replaced by AMI meters are also functionalized to this category and allocated in the same proportion as the Company's investment in AMI meters. 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, working capital and pension and other post-retirement benefit ("OPEB") assets, which are discussed below.

- Materials and supplies were functionalized, classified and allocated among rate classes in proportion to plant in service.
- Accumulated deferred income taxes were 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. Yin (see PECO Exhibit JD-7, page 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.
- 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 directly assigned to

Energy and Transmission based on the results of the lead-lag study prepared by Mr. Yin and described in PECO Statement No. 3. Energy-related working capital requirements were calculated for each rate class in the same manner that Mr. Yin calculated the total working capital. Transmission-related working capital requirements were calculated for each rate class in the same manner that Mr. Yin calculated the total working capital. The cost by class of service was directly assigned in proportion to costs that are allocated on the basis of PJM's methodology. PJM allocates such costs in proportion to contributions to the single coincident peak experienced in the prior year. The balance of working capital was functionalized, classified and calculated for each rate class using the same methodology employed by Mr. Yin.

- The pension asset and OPEB Accumulated Deferred Tax Asset, which are discussed by Mr. Yin in PECO Statement No. 3, are directly related to employees and, therefore, were functionalized, classified and allocated among rate classes based on the direct labor component of operating expenses.

25. 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 accounting and customer service expenses;
- Administrative and general expenses;
- Depreciation expense;
- Taxes other than income taxes; and
- Income taxes.

26. Q. In determining how to treat these expenses in the COS study, was there any other 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 on the basis of 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. Yin.

27. 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 COS study also includes costs of purchased power and transmission costs paid to PJM that are recovered through GSA, TSC and NBT charges. Purchased power costs were functionalized as Energy, classified as energy-related and allocated on the basis of default service sales. Transmission-related costs were functionalized as Transmission and assigned among rate classes based on their contributions to the single PJM coincident peak, which is the same basis on which PJM determines its charges to PECO for transmission service and thus used by PECO for budgeting purposes.

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.

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

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

- **Customer records and collection expenses** relate to billing, call center operations, payment processing, arrearage recoveries, support for administering 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 the 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 an historic three-year period (2015-2017) (see PECO Exhibit JD-7, p. 11).
- **Miscellaneous customer accounts expense** includes IT support for the other customer account functions.
- **Customer assistance expense** comprises expenses incurred for the Low Income Usage Reduction Program, marketing and conservation. Costs specific to the residential class were allocated to Rates R and RH based on number of customers. General marketing and conservation costs were allocated based on sales (see PECO Exhibit JD-7, p 10).

29. 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, general advertising expenses, miscellaneous general expenses, maintenance of general plant, and rents.

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 plant in service.

Regulatory commission expenses, general advertising, and miscellaneous general expense were functionalized, classified, and allocated among rate classes in proportion to revenue.

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

A. Depreciation expense was derived from PECO Exhibit SAB-3, which is sponsored by Mr. Bailey and PECO Exhibit No. BSY-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.

31. 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; and real estate taxes were allocated based on total plant;

32. 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 on the basis of taxable revenue.

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

A. Income tax expense, calculated on the basis of revenue at present rates, was functionalized, classified and calculated for each rate class using the same methodology employed by Mr. Yin in PECO Exhibit BSY-1, Schedule D-18.

34. 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 MK-6. 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 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 on the basis of PJM's methodology. PJM allocates such costs in proportion to contributions to the single coincident peak experienced in the prior year. 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 pole rental revenue and was functionalized, classified and allocated in the same ratio as the plant costs for poles, towers and fixtures.

Decommissioning payments in the FPFTY represent PECO's transfer 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 to Exelon Generation Company were approved in the Commission's Order approving the

Settlement of PECO's restructuring proceeding.[5] 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.

IV. DEVELOPMENT OF RATE CLASS REVENUE REQUIREMENT

35. 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 Company witness Mr. Yin to compute the overall revenue requirement for the FPFTY. Thus, the revenue requirements for each rate class are the sum of that class' 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' 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

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[5] *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 or not 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).

return on rate base for the class at the applicable statutory income tax rates. PECO Exhibit JD-1, line 64, 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, line 69, shows the portion of the total revenue requirements PECO proposes to collect in distribution rates.

36. 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. Yin in PECO Exhibit BSY-1, Schedule A-1, with respect to the overall revenue requirement and revenue deficiency. The increases or (decreases) 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 line 120, which total $142.5 million. The increases or (decreases) in class distribution revenue are shown on line 70, which total $147.0 million. The (decrease) in Transmission revenue under the TSC are shown on line 95, which total, on a net basis, ($1.9) million, and the (decrease) in Purchased Power revenue under the GSA of ($2.5) million is shown on line 83. In addition, forfeited discounts are expected to increase by $0.6 million as a result of the increase in distribution rates.

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

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

A. PECO Exhibit JD-1, which sets forth the substance of the COS study, compares the revenue at current rates by rate class to the revenue requirement allocated on a cost-of-service basis to each rate class. Net income at present rates, shown on line 16, is computed by subtracting operating expenses, depreciation and amortization, taxes other than income taxes, and income taxes (lines 10 to 14) from revenue at present rates (line 7). The return on rate base at present rates for each rate class is shown on line 25, and the relative rates of return are shown on line 26.

Line 114 shows each rate class' revenue requirement (including revenue from distribution charges, transmission charges, purchased power, forfeited discounts and other revenue) at the proposed overall rate of return. Line 107 shows operating expenses, line 108 shows depreciation and amortization expense, line 110 shows gross receipts tax, and line 111 shows income tax expense. Line 104 shows operating income assuming each rate class pays its full cost-of-service. Line 120 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. Line 70 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. Line 95 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.

38. Q. What information is shown on PECO Exhibit JD-2.

A. PECO Exhibit JD-2, as noted above, is the rate class cost of service and 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. This information is contained on the first 15 pages of the exhibit.

Also included in this exhibit are the external and internal allocators used for the rate class allocations, which are shown on pages 15-31 of the exhibit.

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

A. PECO Exhibit JD-3 contains the COS study by functional category and classification. The summary appears on pages 1-6 and the account by account allocation to functional category and classification is provided on pages 7 to 33. Pages 33 to 66 of this exhibit provide the external and internal allocators used for the exhibit.

40. 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.

41. 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 COS study 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.

The costs typically considered in Pennsylvania in developing residential customer charges exclude allocated portions of the distribution system. PECO Exhibit JD-5 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.

42. 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 is 4 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.

43. 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 and 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. Kehl uses these costs to determine the appropriate charge for the NSR as discussed in PECO Statement No. 7.

44. 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 COS study. 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 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. 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 2014-2017. PECO does not account for services separately and, therefore, has used estimated replacement cost to allocate the account to the classes of service. In addition, the services allocation factor reflects the fact that there are some instances where multiple meters are served by a single service.

Meter Costs (page 7) - Meter costs are maintained separately for the residential and C&I class for meters installed as part of the new AMI system. Therefore, meter costs were directly assigned between residential and C&I customers. AMI meter costs were allocated between the commercial and industrial classes based on the number of meters. The cost of replacing legacy MV-90 meters was allocated between the commercial and industrial classes based on the number of MV-90 meters.

The unrecovered costs of legacy AMR meters were allocated among the residential, commercial and industrial classes in the same proportion as AMI meter costs.

Customer Deposits (page 8) - Allocates FPFTY customer deposits based on the average customer deposit balances for each class as of the end of 2017.

Acct 903 Allocator (page 9) - Allocates costs associated with each activity recorded in Account 903 – Customer Records and Collection 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 7 summarizes the costs by rate class. The weighted allocators are shown on row 8. The separate allocations are necessary because some costs are only applicable to specific rate classes.

Acct 908 Allocator (page 10) - Allocates the costs of each activity recorded in Account 908 – Customer Assistance using an appropriate external allocator. Rows 1-4 list each activity, the cost of the activity and the allocator assigned to it. Row 5 summarizes the costs by rate class. The allocators are on row 6.

Write-Offs (page 11) - Computes the Write-Off allocators using net charge-offs for 2015-2017.

Over 60-Day (page 12) - 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 July 2016 to June 2017.

Purchase of Receivables (page 13) - Computes the allocator used in the COS study to allocate the POR portion of cash working capital.

Demand Allocators (page 14) - Computes the demand allocators used in the COS study.

MWh Sales at Voltage Levels (page 15) - Computes MWh at the different voltage levels based on projected 2019 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 Tariff.

Customer and Location-Based Allocators (page 2) – The customer-based and location-based allocators are shown on page 2 at lines 8-12. The location-based allocator (Location Secondary) shown on line 12 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 some 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.

45. Q. Please explain how the purchased power and transmission sections of the COS study 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 $0.00019 per kWh will replace the rate of $0.00034 per kWh currently in the GSA. The rate developed in PECO Exhibit JD-9 of $221 per MW-year will replace the current rate of $363 per MW-year in the TSC.

46. Q. Please summarize your conclusions with respect to cost of service.

A. The Company's COS study was prepared using an appropriate and well-accepted cost of service method. The results of the Company's COS study 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.

VI. ANALYSIS OF HIGH VOLTAGE CUSTOMERS IN ACCORDANCE WITH THE SETTLEMENT OF PECO'S 2015 RATE CASE

47. Q. Since its last base rate proceeding in 2015, has the Company performed further investigation of the distribution system costs for customers served at 69 kV and higher?

A. Yes. PECO first reviewed its billing records and identified 17 customers receiving service at voltage levels of 69 kV and higher. The Company then analyzed the configuration of those customers to more clearly define the portion of substation facilities performing a distribution function for those customers. Based on this review, PECO determined that high voltage customers are served primarily by the higher voltage side of a substation. However, a portion of the substation equipment (e.g., the breaker to which a radial line connects) serves a distribution function. In addition, under the FERC seven factor test,[6] high voltage lines that serve specific customers and are radial in nature are classified as distribution plant. In fact, between 2009 and 2013, the Company transferred over $16 million of plant operating at voltages of 69 kV and higher from its transmission plant accounts to distribution Accounts 364 to 367 in order to conform with the FERC seven factor test. That $16 million is not the only investment in distribution facilities operating at 69 kV and higher voltages that is serving PECO's higher voltage customers.

48. Q. Is PECO proposing any changes to the allocation of distribution costs to customers served at 69 kV and higher?

A. Yes. The Company currently provides a high voltage discount to account for the way higher voltage customers use substation transformation. However, based on its efforts to more clearly define the portion of the distribution system used by high voltage customers, PECO is proposing to increase the High Voltage Distribution Discount under Rate HT to $1.29 per kW from the current rate of $0.48 per kW to reflect removal of customers served at 69 kV or higher from the allocation of distribution substation equipment costs. Mr. Kehl discusses the changes to the High Voltage Distribution Discount provided under Rate HT to customers that

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[6] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,783-84 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom., New York v. FERC*, 535 U.S. 1 (2002).

receive service at 69 kV and higher voltages in more detail in PECO Statement No. 7.

49. Q. Should PECO customers served at or within one span of a PECO-owned substation or with intermittent renewable generation be treated similarly to customers served at 69 kV or higher in the COS study?

A. No. Customers at or within one span of a PECO-owned substation are served at voltages of 33 kV or lower and, thus, are still distribution customers taking service from a distribution substation. This group of customers should not be afforded special treatment, using the arbitrary criterion of proximity to a Company-owned substation. That approach is antithetical to the concept of a “class” cost-of-service study, which allocates costs based on reasonable, discernible class usage characteristics and not based on measures such as the length of a conductor that serves one particular customer.

Similarly, customers with intermittent generation are no different than any other customer served at the same voltage and require the same level of investment in distribution facilities, including poles, wires, transformers, and substation equipment. In fact, these customers are typically served by the same distribution facilities before and after they add generation.

VII. CONCLUSION

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

A. Yes, it does.

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
S	1	**SUMMARY AT PRESENT RATES**									
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**									
S	3	OPERATING REVENUE									
S	4	Sales of Electricity - Base	CALCULATED	1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
S	5	Decommissioning Revenues	CALCULATED	(3,860)	(1,085)	(281)	(832)	(42)	(1,535)	(65)	(21)
S	6	Other Operating Revenue	CALCULATED	37,547	21,475	5,048	6,360	207	3,777	226	454
S	7	TOTAL OPERATING REVENUE		1,258,261	701,465	141,202	230,378	8,343	148,996	7,368	20,508
S	8										
S	9	OPERATING EXPENSES									
S	10	Operation and Maintenance Expense	CALCULATED	619,817	363,611	75,695	97,515	3,930	66,658	3,786	8,623
S	11	Depreciation and Amortization Expense	CALCULATED	235,063	129,891	27,778	43,842	1,425	26,513	1,593	4,022
S	12	Taxes Other Than Income Taxes-General	CALCULATED	20,557	10,650	2,429	3,664	149	3,225	195	247
S	13	Taxes Other Than Income Taxes-Distribution GRT	CALCULATED	70,638	39,007	7,783	13,135	481	8,623	425	1,184
S	14	Income Taxes	CALCULATED	34,406	17,181	1,212	9,669	323	5,240	(67)	847
S	15	TOTAL OPERATING EXPENSES		980,481	560,339	114,896	167,825	6,308	110,258	5,933	14,923
S	16	**OPERATING INCOME (RETURN)**		277,780	141,126	26,306	62,554	2,035	38,737	1,436	5,586
S	17										
S	18	**DEVELOPMENT OF RATE BASE**									
S	19	Electric Plant in Service	CALCULATED	7,193,628	3,636,594	865,331	1,476,537	45,337	966,192	60,550	143,088
S	20	Less: Accumulated Depreciation	CALCULATED	2,041,533	1,021,807	239,980	423,519	12,280	273,546	17,056	53,345
S	21	Plus: Rate Base Additions	CALCULATED	465,301	260,118	53,310	81,615	3,184	58,898	2,620	5,555
S	22	Less: Rate Base Deductions	CALCULATED	796,981	375,232	93,915	190,433	4,723	109,005	6,784	16,889
S	23	**TOTAL DISTRIBUTION RATE BASE**	CALCULATED	4,820,415	2,499,673	584,746	944,200	31,518	642,538	39,330	78,409
S	24										
S	25	**DISTRIBUTION RATE OF RETURN (PRESENT)**		5.76%	5.65%	4.50%	6.63%	6.46%	6.03%	3.65%	7.12%
S	26	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**		1.00	0.98	0.78	1.15	1.12	1.05	0.63	1.24
S	27										
S	28	**DEVELOPMENT OF PURCHASED POWER RETURN**									
S	29	Purchased Electric Revenues	CALCULATED	653,769	418,108	109,879	92,584	862	31,629	0	708
S	30	Purchased Power O&M Expense	CALCULATED	610,818	390,640	102,660	86,502	805	29,551	0	661
S	31	Purchased Power GRT Expense	CALCULATED	38,572	24,668	6,483	5,462	51	1,866	0	42
S	32	Purchased Power Income Taxes		1,155	739	194	164	2	56	0	1
S	33	Purchased Power Operating Income		3,224	2,062	542	457	4	156	0	3
S	34	Rate Base - Purchased Pwr Cash Working Capita	CALCULATED	19,631	12,554	3,299	2,780	26	950	0	21
S	35	**PURCHASED POWER RATE OF RETURN (PRESENT)**		16.42%	16.42%	16.42%	16.42%	16.42%	16.42%	0.00%	16.42%
S	36										
S	37	**DEVELOPMENT OF TRANSMISSON RETURN**									
S	38	Transmission Revenues	CALCULATED	185,615	86,438	22,449	38,019	1,136	35,728	1,754	91
S	39	Transmission O&M Expense	CALCULATED	172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
S	40	Transmission GRT Expense	CALCULATED	10,951	5,100	1,324	2,243	67	2,108	104	5
S	41	Transmission Income Taxes		672	314	83	138	4	126	6	0
S	42	Transmission Operating Income		1,773	825	212	363	11	345	17	1
S	43	Rate Base - Transmission Cash Working Capital	CALCULATED	6,141	2,676	387	1,167	55	1,778	75	4
S	44	**TRANSMISSION RATE OF RETURN (PRESENT)**		28.87%	30.82%	54.97%	31.09%	20.03%	19.39%	22.45%	20.50%
S	45										
S	46	**TOTAL OPERATING INCOME (RETURN)**		282,776	144,012	27,060	63,373	2,050	39,238	1,452	5,590
S	47	**TOTAL RATE BASE**		4,846,186	2,514,903	588,432	948,146	31,599	645,266	39,406	78,435
S	48	**COMPOSITE RATE OF RETURN @ CURRENT RATES**		5.84%	5.73%	4.60%	6.68%	6.49%	6.08%	3.69%	7.13%

PECO Energy Company
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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S	49										
S	50										
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 7.79%**									
S	52	**DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)**									
S	53	**RATE BASE**	CALCULATED	4,820,415	2,499,673	584,746	944,200	31,518	642,538	39,330	78,409
S	54	**RETURN (RATE BASE * 7.79% ROR)**		375,309	194,620	45,527	73,514	2,454	50,027	3,062	6,105
S	55	**PLUS:**									
S	56	**OPERATING EXPENSES**									
S	57	Operation and Maintenance Expense	CALCULATED	621,586	364,580	76,045	97,710	3,938	66,863	3,817	8,632
S	58	Depreciation and Amortization Expense	CALCULATED	235,063	129,891	27,778	43,842	1,425	26,513	1,593	4,022
S	59	Taxes Other Than Income Taxes-General	CALCULATED	20,557	10,650	2,429	3,664	149	3,225	195	247
S	60	Taxes Other Than Income Taxes-Distribution GRT	CALCULATED	79,310	43,764	9,492	14,109	518	9,627	570	1,230
S	61	State and Federal Income Taxes	CALCULATED	74,034	38,917	9,022	14,123	494	9,828	594	1,058
S	62	**TOTAL OPERATING EXPENSES**		1,030,551	587,801	124,766	173,448	6,523	116,055	6,768	15,190
S	63										
S	64	**EQUALS TOTAL COST OF SERVICE**		1,405,860	782,421	170,293	246,962	8,977	166,082	9,831	21,294
S	65	**LESS:**									
S	66	Decommissioning Revenues	CALCULATED	(3,860)	(1,085)	(281)	(832)	(42)	(1,535)	(65)	(21)
S	67	Other Operating Revenue	CALCULATED	38,162	21,812	5,170	6,428	210	3,848	237	458
S	68	**EQUALS:**									
S	69	**DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.79%**		1,371,557	761,694	165,404	241,366	8,809	163,769	9,658	20,858
S	70	Distribution Cost Increase without Forfeited Discount		146,985	80,620	28,970	16,515	631	17,015	2,452	782
S	71	**TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE**		147,599	80,956	29,091	16,583	634	17,087	2,462	786
S	72	**REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEI**		12.00%	11.84%	21.23%	7.35%	7.72%	11.59%	34.02%	3.90%
S	73			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	74	**DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)**									
S	75	**RATE BASE (CWC)**	CALCULATED	19,631	12,554	3,299	2,780	26	950	0	21
S	76	**RETURN (RATE BASE * 7.79% ROR)**		1,528	977	257	216	2	74	0	2
S	77	**PLUS:**									
S	78	**OPERATING EXPENSES**									
S	79	Purchased Power O&M Expense	CALCULATED	610,818	390,640	102,660	86,502	805	29,551	0	661
S	80	Purchased Power Income Taxes	CALCULATED	466	298	78	66	1	23	0	1
S	81	Purchased Power GRT Expense	CALCULATED	38,423	24,573	6,458	5,441	51	1,859	0	42
S	82	**EQUALS TOTAL PURCHASED POWER COST OF SERVICE**		651,236	416,488	109,453	92,225	858	31,506	0	705
S	83	**TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREAS**		(2,533)	(1,620)	(426)	(359)	(3)	(123)	0	(3)
S	84	**REVENUE INCREASE TO DISTRIBUTION REVENUES (%)**		-0.39%	-0.39%	-0.39%	-0.39%	-0.39%	-0.39%	0.00%	-0.39%
S	85			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	0.00%	7.79%
S	86	**DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)**									
S	87	**RATE BASE (CWC)**	CALCULATED	6,141	2,676	387	1,167	55	1,778	75	4
S	88	**RETURN (RATE BASE * 7.79% ROR)**		478	208	30	91	4	138	6	0
S	89	**PLUS:**									
S	90	**OPERATING EXPENSES**									
S	91	Transmission O&M Expense	CALCULATED	172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
S	92	Transmission Income Taxes	CALCULATED	146	64	9	28	1	42	2	0
S	93	Transmission GRT Expense	CALCULATED	10,837	5,046	1,308	2,219	66	2,090	103	5
S	94	**EQUALS TOTAL TRANSMISSION COST OF SERVICE**		183,679	85,517	22,177	37,613	1,126	35,420	1,738	90
S	95	**TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREAS**		(1,935)	(921)	(273)	(406)	(10)	(308)	(16)	(1)
S	96	**REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)**		-1.04%	-1.07%	-1.21%	-1.07%	-0.88%	-0.86%	-0.94%	-0.89%

PECO Energy Company
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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S	97			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	98	**TOTAL INCREASE (DECREASE) REQUIRED**		143,130	78,414	28,393	15,818	620	16,656	2,446	782
S	99										
S	100										
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.79%**									
S	102	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**									
S	103	**RATE BASE**	CALCULATED	4,846,186	2,514,903	588,432	948,146	31,599	645,266	39,406	78,435
S	104	**RETURN (RATE BASE * 7.79% ROR)**		377,315	195,806	45,814	73,821	2,460	50,239	3,068	6,107
S	105	**PLUS:**									
S	106	**OPERATING EXPENSES**									
S	107	Operation and Maintenance Expense	CALCULATED	1,404,623	835,419	199,534	219,487	5,797	129,564	5,444	9,378
S	108	Depreciation and Amortization Expense	CALCULATED	235,063	129,891	27,778	43,842	1,425	26,513	1,593	4,022
S	109	Taxes Other Than Income Taxes-General	CALCULATED	20,557	10,650	2,429	3,664	149	3,225	195	247
S	110	Taxes Other Than Income Taxes-GRT	CALCULATED	128,570	73,382	17,258	21,770	635	13,576	672	1,277
S	111	State and Federal Income Taxes	CALCULATED	74,646	39,279	9,109	14,216	496	9,892	595	1,058
S	112	**TOTAL OPERATING EXPENSES**		1,863,460	1,088,620	256,108	302,979	8,501	182,769	8,500	15,983
S	113										
S	114	**EQUALS TOTAL COST OF SERVICE**		2,240,775	1,284,426	301,923	376,800	10,961	233,008	11,568	22,089
S	115	**LESS:**									
S	116	Decommissioning Revenues	CALCULATED	(3,860)	(1,085)	(281)	(832)	(42)	(1,535)	(65)	(21)
S	117	Other Operating Revenue	CALCULATED	38,162	21,812	5,170	6,428	210	3,848	237	458
S	118	**EQUALS:**									
S	119	**OVERALL BASE RATES @ EQUALIZED ROR 7.79%**		2,206,473	1,263,699	297,033	371,204	10,793	230,695	11,396	21,653
S	120	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFE**		142,515	78,077	28,271	15,750	618	16,584	2,435	779
S	121	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**		143,130	78,414	28,393	15,818	620	16,656	2,446	782
S	122			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	123										
S	124										
S	125										
S	126										
S	127										
S	128										
S	129										
S	130										
S	131										
S	132										
S	133										
S	134										
S	135										
S	136										
S	137										
S	138										
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S	140										
S	141										
S	142										
S	143										
S	144										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S	145										
S	146										
S	147										
S	148										
S	149										
S	150										
RBP	1	**DEVELOPMENT OF RATE BASE**									
RBP	2	**ELECTRIC PLANT IN SERVICE**									
RBP	3	INTANGIBLE PLANT									
RBP	4	302-303-Franchise and consents & Misc Inta	TDPLT	91,924	45,947	11,079	19,101	580	12,550	790	1,877
RBP	5	302-	CUSTRES	0	0	0	0	0	0	0	0
RBP	6	303-	CUST	0	0	0	0	0	0	0	0
RBP	7	303-AMI Plant	CMETERS	83,726	61,107	8,800	11,509	330	1,951	28	0
RBP	8	TOTAL INTANGIBLE PLANT		175,650	107,054	19,880	30,610	910	14,501	818	1,877
RBP	9										
RBP	10	TRANSMISSION PLANT									
RBP	11	350-359 Accounts	DTRAN	0	0	0	0	0	0	0	0
RBP	12	361- Transmission Related Plant	DTRAN	0	0	0	0	0	0	0	0
RBP	13	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0
RBP	14										
RBP	15	DISTRIBUTION PLANT									
RBP	16	360-Land & Land Rights	DDISPHT	42,884	16,217	4,887	8,640	380	11,747	747	267
RBP	17	361-Structures & Improvements	DDISPHT	139,261	52,664	15,870	28,056	1,233	38,147	2,425	866
RBP	18	362-Station Equipment	DDISPHT	1,163,133	439,858	132,546	234,330	10,302	318,614	20,253	7,232
RBP	19	364-Poles,Towers & Fixtures									
RBP	20	Primary HT	DDISPHT	333,905	126,272	38,050	67,270	2,957	91,466	5,814	2,076
RBP	21	Primary	DDISTPOL	210,305	112,226	33,818	59,787	2,628	0	0	1,845
RBP	22	Secondary	CDISTSOLC	209,812	161,397	23,243	18,834	0	0	0	6,338
RBP	23	Total Account 364		754,022	399,895	95,111	145,891	5,586	91,466	5,814	10,259
RBP	24	365-Overhead Conductors & Devices									
RBP	25	Primary HT	DDISPHT	594,249	224,725	67,718	119,720	5,263	162,781	10,347	3,695
RBP	26	Primary	DDISTPOL	374,278	199,728	60,185	106,403	4,678	0	0	3,284
RBP	27	Secondary	CDISTSULC	373,401	287,238	41,365	33,519	0	0	0	11,280
RBP	28	Total Account 365		1,341,927	711,690	169,269	259,641	9,941	162,781	10,347	18,259
RBP	29	366-Underground Conduit									
RBP	30	Primary HT	DDISPHT	269,392	101,875	30,699	54,273	2,386	73,794	4,691	1,675
RBP	31	Primary	DDISTPUL	82,541	44,047	13,273	23,466	1,032	0	0	724
RBP	32	Secondary	CDISTSOLC	112,290	86,378	12,439	10,080	0	0	0	3,392
RBP	33	Total Account 366		464,223	232,300	56,411	87,818	3,418	73,794	4,691	5,791
RBP	34	367-Underground Conductors & Devices									
RBP	35	Primary HT	DDISPHT	796,621	301,255	90,779	160,490	7,056	218,216	13,871	4,953
RBP	36	Primary	DDISTPUL	244,084	130,252	39,250	69,390	3,051	0	0	2,142
RBP	37	Secondary	CDISTSULC	332,053	255,430	36,785	29,807	0	0	0	10,031
RBP	38	Total Account 367		1,372,757	686,937	166,814	259,688	10,106	218,216	13,871	17,126
RBP	39	368-Line Transformers	DDISTSUT	634,209	342,720	103,274	182,580	0	0	0	5,635
RBP	40	369-Services	CSERVICE	433,534	242,431	34,913	153,053	454	2,684	0	0
RBP	41	370-Meters	CMETERS	346,878	253,168	36,459	47,684	1,367	8,083	118	0
RBP	42	371-Installation on Customer Premises	CUSTPREM	13,772	10,594	1,526	1,236	0	0	0	416

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
RBP	43	373-Street Lighting & Signal Systems	CLIGHT	72,548	0	0	0	0	0	0	72,548
RBP	44	374-Asset Retirement Costs for Distribution P	DISTPLTXAR	1,893	946	228	393	12	258	16	39
RBP	45	TOTAL DISTRIBUTION PLANT		6,781,042	3,389,420	817,306	1,409,010	42,798	925,789	58,280	138,437
RBP	46										
RBP	47										
RBP	48										
RBP	49										
RBP	50										
RBP	51	**ELECTRIC PLANT IN SERVICE CONTINUED**									
RBP	52										
RBP	53	GENERAL PLANT									
RBP	54	389-Land and Land Rights	SALWAGES	943	558	112	147	6	103	6	11
RBP	55	390-Structures and Improvements	SALWAGES	44,443	26,283	5,279	6,925	305	4,858	272	520
RBP	56	391-Office Furniture & Equipment	SALWAGES	14,402	8,517	1,711	2,244	99	1,574	88	169
RBP	57	393-Store Equipment	SALWAGES	35	21	4	5	0	4	0	0
RBP	58	394-Tools, Shop & Garage Equip.	SALWAGES	30,362	17,956	3,607	4,731	209	3,319	186	355
RBP	59	395-Laboratory Equipment	SALWAGES	372	220	44	58	3	41	2	4
RBP	60	397-Communication Equipment	SALWAGES	144,410	85,402	17,154	22,500	992	15,787	885	1,691
RBP	61	398-Miscellaneous Equipment / ARO	SALWAGES	485	287	58	76	3	53	3	6
RBP	62	399-Other Tangible Property	SALWAGES	1,483	877	176	231	10	162	9	17
RBP	63	TOTAL GENERAL PLANT		236,936	140,120	28,145	36,917	1,628	25,902	1,451	2,774
RBP	64										
RBP	65										
RBP	66	**TOTAL ELECTRIC PLANT IN SERVICE**		7,193,628	3,636,594	865,331	1,476,537	45,337	966,192	60,550	143,088
RBP	67										
RBP	68										
RBP	69										
RBP	70										
RBP	71										
RBP	72										
RBP	73										
RBP	74										
RBP	75										
RBP	76										
RBP	77										
RBP	78										
RBP	79										
RBP	80										
RBP	81										
RBP	82										
RBP	83										
RBP	84										
RBP	85										
RBP	86										
RBP	87										
RBP	88										
RBP	89										
RBP	90										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
RBP	91										
RBP	92										
RBP	93										
RBP	94										
RBP	95										
RBP	96										
RBP	97										
RBP	98										
RBP	99										
RBP	100										
RBD	1	**LESS: ACCUMULATED DEPRECIATION**									
RBD	2										
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRI	INTPLT	118,520	72,235	13,414	20,654	614	9,785	552	1,266
RBD	4										
RBD	5	TRANSMISSION PLANT ACCUMULATED DE	TRANPLT	0	0	0	0	0	0	0	0
RBD	6										
RBD	7	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION									
RBD	8	360-Land & Land Rights	PLT_360	0	0	0	0	0	0	0	0
RBD	9	361-Structures & Improvements	PLT_361	40,671	15,380	4,635	8,194	360	11,141	708	253
RBD	10	362-Station Equipment	PLT_362	465,114	175,891	53,002	93,704	4,119	127,407	8,099	2,892
RBD	11	364-Poles,Towers & Fixtures	PLT_364	157,920	83,753	19,920	30,555	1,170	19,156	1,218	2,149
RBD	12	365-Overhead Conductors & Devices	PLT_365	281,578	149,335	35,518	54,481	2,086	34,156	2,171	3,831
RBD	13	366-Underground Conduit	PLT_366	166,178	83,157	20,194	31,436	1,223	26,416	1,679	2,073
RBD	14	367-Underground Conductors & Devices	PLT_367	208,793	104,482	25,372	39,498	1,537	33,190	2,110	2,605
RBD	15	368-Line Transformers	PLT_368	196,182	106,014	31,946	56,478	0	0	0	1,743
RBD	16	369-Services	PLT_369	168,597	94,279	13,577	59,521	176	1,044	0	0
RBD	17	370-Meters	PLT_370	117,277	85,594	12,327	16,122	462	2,733	40	0
RBD	18	371-Installation on Customer Premises	PLT_371	7,907	6,083	876	710	0	0	0	239
RBD	19	373-Street Lighting & Signal Systems	PLT_373	35,370	0	0	0	0	0	0	35,370
RBD	20	374-Asset Retirement Costs for Distribution P	DISTPLTXAR	1,990	995	240	414	13	272	17	41
RBD	21	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIA		1,847,578	904,962	217,606	391,111	11,147	255,515	16,041	51,196
RBD	22										
RBD	23	GENERAL PLANT ACCUMULATED DEPREC	GENLPLT	75,435	44,611	8,961	11,753	518	8,247	462	883
RBD	24										
RBD	25	**TOTAL ACCUMULATED DEPRECIATION**		2,041,533	1,021,807	239,980	423,519	12,280	273,546	17,056	53,345
RBD	26										
RBD	27										
RBD	28										
RBD	29	**NET ELECTRIC PLANT IN SERVICE**		5,152,095	2,614,787	625,350	1,053,018	33,057	692,646	43,495	89,743
RBD	30										
RBD	31										
RBD	32										
RBD	33										
RBD	34										
RBD	35										
RBD	36										
RBD	37										
RBD	38										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
RBD	39										
RBD	40										
RBD	41										
RBD	42										
RBD	43										
RBD	44										
RBD	45										
RBD	46										
RBD	47										
RBD	48										
RBD	49										
RBD	50										
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**									
RBO	2										
RBO	3	**PLUS: ADDITIONS TO RATE BASE**									
RBO	4										
RBO	5	COMMON PLANT	SALWAGES	326,144	192,876	38,741	50,816	2,241	35,654	1,998	3,818
RBO	6										
RBO	7	**WORKING CAPITAL**									
RBO	8	Purchased Power Cash Working Capital	CALCULATED	19,631	12,554	3,299	2,780	26	950	0	21
RBO	9	Transmission Cash Working Capital	CALCULATED	6,141	2,676	387	1,167	55	1,778	75	4
RBO	10	Distribution									
RBO	11	Cash Working Capital	CALCULATED	123,280	59,216	12,659	27,540	843	21,111	489	1,421
RBO	12	Materials and Supplies	TOTPLT	15,876	8,026	1,910	3,259	100	2,132	134	316
RBO	13	Total Distribution Working Capital		139,156	67,242	14,569	30,799	943	23,244	622	1,737
RBO	14	TOTAL WORKING CAPITAL		164,928	82,473	18,255	34,746	1,024	25,971	697	1,763
RBO	15	TOTAL ADDITIONS TO RATE BASE		491,072	275,348	56,996	85,562	3,265	61,625	2,695	5,581
RBO	16										
RBO	17	**LESS: DEDUCTIONS TO RATE BASE**									
RBO	18	Customer Deposits	CUSTDEP	50,574	16,904	3,832	26,668	144	3,026	0	0
RBO	19	Customer Advances for Construction	CUSTADV	959	495	119	184	7	133	8	13
RBO	20	Deferred Income Taxes and Credits									
RBO	21	Plant	TOTPLT	986,701	498,807	118,692	202,527	6,219	132,526	8,305	19,626
RBO	22	Common Plant	SALWAGES	22,489	13,300	2,671	3,504	155	2,458	138	263
RBO	23	Pension Asset & OPEB Contribution	SALWAGES	(208,230)	(123,143)	(24,735)	(32,444)	(1,431)	(22,764)	(1,275)	(2,438)
RBO	24	Unamortized AMR Investment	CMETERS	(11,551)	(8,430)	(1,214)	(1,588)	(46)	(269)	(4)	0
RBO	25	Contributions in Aid of Construction (CIAC)	CUSTADV	(43,961)	(22,700)	(5,450)	(8,417)	(325)	(6,106)	(388)	(575)
RBO	26	Total Deferred Income Taxes and Credits		745,448	357,833	89,964	163,581	4,572	105,846	6,776	16,877
RBO	27	TOTAL DEDUCTIONS TO RATE BASE		796,981	375,232	93,915	190,433	4,723	109,005	6,784	16,889
RBO	28										
RBO	29										
RBO	30	Total Distribution Additions to Rate Base		465,301	260,118	53,310	81,615	3,184	58,898	2,620	5,555
RBO	31										
RBO	32	TOTAL PURCHASED POWER RATE BASE		19,631	12,554	3,299	2,780	26	950	0	21
RBO	33	TOTAL TRANSMSSION RATE BASE		6,141	2,676	387	1,167	55	1,778	75	4
RBO	34	TOTAL DSTRIBUTION RATE BASE		4,820,415	2,499,673	584,746	944,200	31,518	642,538	39,330	78,409
RBO	35										
RBO	36	**TOTAL RATE BASE**		4,846,186	2,514,903	588,432	948,146	31,599	645,266	39,406	78,435

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
RBO	37										
RBO	38										
RBO	39										
RBO	40										
RBO	41										
RBO	42										
RBO	43										
RBO	44										
RBO	45										
RBO	46										
RBO	47										
RBO	48										
RBO	49										
RBO	50										
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	146,785	86,806	17,436	22,870	1,009	16,047	899	1,719
RBC	5	Pension	SALWAGES	13,055	7,721	1,551	2,034	90	1,427	80	153
RBC	6	Other Expenses	OMXPPPP	533,238	293,768	65,473	91,312	3,269	69,901	3,761	5,753
RBC	7	TOTAL EXPENSES		693,079	388,295	84,460	116,217	4,368	87,375	4,740	7,625
RBC	8	POR Working Capital	POR	1,062,743	337,427	87,289	336,728	7,805	286,508	0	6,987
RBC	9	TOTAL EXPENSES PER DAY		4,810	1,988	471	1,241	33	1,024	13	40
RBC	10										
RBC	11	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG		67,948	28,084	6,646	17,528	471	14,469	183	565
RBC	12										
RBC	13	AVERAGE PREPAYMENTS		7,018	4,145	811	1,182	39	704	37	101
RBC	14	DISTRIBUTION ACCRUED TAXES		59,644	32,715	6,564	11,155	405	7,461	364	980
RBC	15	INTEREST PAYMENTS	TOTPLT	(11,330)	(5,728)	(1,363)	(2,326)	(71)	(1,522)	(95)	(225)
RBC	16										
RBC	17										
RBC	18	NET DISTRIBUIOTN CASH WORKING CAPITAL REQUIREM		123,280	59,216	12,659	27,540	843	21,111	489	1,421
RBC	19										
RBC	20										
RBC	21	**PURCHASED POWER**									
RBC	22	O&M EXPENSE RELATED CASH WORKING CAPITAL									
RBC	23	Commodity Purchased - Contract Purchases	ENERGY1	605,850	387,462	101,825	85,798	798	29,311	0	656
RBC	24	Commodity Purchased - Spot Market Purcha	ENERGY1	4,968	3,177	835	704	7	240	0	5
RBC	25	TOTAL EXPENSES		610,819	390,640	102,660	86,502	805	29,551	0	661
RBC	26										
RBC	27	TOTAL EXPENSES PER DAY		1,673	1,070	281	237	2	81	0	2
RBC	28										
RBC	29	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE L		19,631	12,554	3,299	2,780	26	950	0	21
RBC	30										
RBC	31	Energy ACCRUED TAXES	ENERGY1	0	0	0	0	0	0	0	0
RBC	32										
RBC	33	NET Energy CASH WORKING CAPITAL REQUIREMENT		19,631	12,554	3,299	2,780	26	950	0	21
RBC	34										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
RBC	35	**TRANSMISSION**									
RBC	36	O&M EXPENSE - PJM Transmission Purcha	DTRAN	64,504	28,108	4,060	12,254	574	18,674	789	45
RBC	37										
RBC	38	TOTAL EXPENSES PER DAY		177	77	11	34	2	51	2	0
RBC	39										
RBC	40	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG		6,141	2,676	387	1,167	55	1,778	75	4
RBC	41										
RBC	42	TRANSMISSION ACCRUED TAXES	DTRAN	0	0	0	0	0	0	0	0
RBC	43										
RBC	44	NET TRANSMISSION CASH WORKING CAPITAL REQUIRE		6,141	2,676	387	1,167	55	1,778	75	4
RBC	45										
RBC	46										
RBC	47	NET TOTAL CASH WORKING CAPITAL REQUIREMENT		149,052	74,447	16,345	31,487	924	23,839	564	1,447
RBC	48										
RBC	49										
RBC	50										
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**									
RBC	2										
RBC	3	**LAG/LEAD DAYS**		**NET DAYS**							
RBC	4	REVENUE LAG DAYS	47.25								
RBC	5	EXPENSE LEAD DAYS	33.17	14.08							
RBC	6	PURCHASED POWER REVENUE LAG DAYS	47.25								
RBC	7	PURCHASED POWER EXP LEAD DAYS	35.52	11.73							
RBC	8	TRANSMISSION REVENUE LAG DAYS	47.25								
RBC	9	TRANSMISSION EXP LEAD DAYS	12.50	34.75							
RBC	10	DISTRIBUTION REVENUE LAG DAYS	47.25								
RBC	11	DISTRIBUTION LEAD DAYS	33.13	14.13							
RBC	12										
RBC	13										
RBC	14										
RBC	15										
RBC	16	DISTRIBUTION ACCRUED TAXES									
RBC	17	Federal Income Tax	EBT	505,781	253,999	37,413	124,681	4,041	72,887	1,400	11,359
RBC	18	State Income Tax	EBT	400,288	201,021	29,609	98,675	3,198	57,685	1,108	8,990
RBC	19	PURTA Taxes	PLT_3601	566,909	214,386	64,602	114,212	5,021	155,292	9,871	3,525
RBC	20	Capital Stock	CAPSTOCK	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	CLAIMREV	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	TOTPLT	336,616	170,170	40,492	69,093	2,121	45,212	2,833	6,696
RBC	23	PA Corp Loan Tax	TOTPLT	0	0	0	0	0	0	0	0
RBC	24	Philadelphia BPT	SALESREV	0	0	0	0	0	0	0	0
RBC	25	Local Privilege Tax	SALESREV	0	0	0	0	0	0	0	0
RBC	26	Gross Receipts Tax	SALESREV	19,960,466	11,101,475	2,223,869	3,665,049	133,303	2,392,080	117,466	327,225
RBC	27	Lag Day Weighted Accrued Taxes		21,770,060	11,941,050	2,395,985	4,071,709	147,685	2,723,156	132,679	357,795
RBC	28	Total Accrued Taxes CWC		59,644	32,715	6,564	11,155	405	7,461	364	980
RBC	29										
RBC	30	DISTRIBUTION AVERAGE PREPAYMENTS									
RBC	31	Call Center	CUST	20	16	2	2	0	0	0	0
RBC	32	EEI and EPRI Dues	CLAIMREV	438	251	59	74	2	46	2	4

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
RBC	33	PUC Assess - Electric	SALESREV	3,692	2,054	411	678	25	443	22	61
RBC	34	Prepaid Rents and Pole Attachment Fees	PLT_364	438	233	55	85	3	53	3	6
RBC	35	Prepaid Barrel Locks	CMETERS	0	0	0	0	0	0	0	0
RBC	36	SEPTA Duct Rentals	PLT_366	0	0	0	0	0	0	0	0
RBC	37	Philadelphia Work Permits	DISTPLT	0	0	0	0	0	0	0	0
RBC	38	Business Support System	CUST	334	262	38	31	0	1	0	2
RBC	39	VEBA Adjustment	SALWAGES	307	182	37	48	2	34	2	4
RBC	40	Facilities Contracts	DISTPLT	74	37	9	15	0	10	1	2
RBC	41	IT Service Contracts	TOTPLT	698	353	84	143	4	94	6	14
RBC	42	Fleet Activities	GENLPLT	208	123	25	32	1	23	1	2
RBC	43	Billing and Research	CUSTBILLS	345	271	39	32	0	1	0	3
RBC	44	Postage	CUSTBILLS	461	363	52	42	0	1	0	3
RBC	45	TOTAL AVERAGE PREPAYMENTS		7,018	4,145	811	1,182	39	704	37	101
RBC	46										
RBC	47										
RBC	48										
RBC	49										
RBC	50										
RBC	51	**OPERATING REVENUES**									
RBC	52										
RBC	53	**SALES REVENUES**									
RBC	54	Sales of Electricity Revenues - Base		1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
RBC	55	Sales of Electricity Revenues - Nuclear Decor	ENERGY2	(3,860)	(1,085)	(281)	(832)	(42)	(1,535)	(65)	(21)
RBC	56	Transmission Revenues	DTRANR	185,615	86,438	22,449	38,019	1,136	35,728	1,754	91
RBC	57	Purchased Electric Revenues	ENERGY1	653,769	418,108	109,879	92,584	862	31,629	0	708
RBC	58	TOTAL SALES OF ELECTRICITY		2,060,099	1,184,537	268,482	354,622	10,133	212,576	8,896	20,853
RBC	59										
RBC	60	**OTHER OPERATING REVENUES**									
RBC	61	Unbilled and Cost Adjustment Revenue	SALESREV	0	0	0	0	0	0	0	0
RBC	62	450-Forfeited Discounts	OX_904	9,406	6,865	1,556	768	10	206	0	1
RBC	63	454-Rent from Electric Property	PLT_364	17,832	9,457	2,249	3,450	132	2,163	137	243
RBC	64	456-Other Electric Revenues	DISTPLT	10,309	5,153	1,242	2,142	65	1,407	89	210
RBC	65	TOTAL OTHER OPERATING REV		37,547	21,475	5,048	6,360	207	3,777	226	454
RBC	66										
RBC	67	**TOTAL OPERATING REVENUES**		2,097,645	1,206,012	273,530	360,982	10,340	216,353	9,122	21,307
RBC	68										
RBC	69										
RBC	70										
RBC	71										
RBC	72										
RBC	73										
RBC	74										
RBC	75										
RBC	76										
RBC	77										
RBC	78										
RBC	79										
RBC	80										

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	RESIDENTIAL (d)	RESIDENTIAL HEATING (e)	GENERAL SERVICE (f)	PRIMARY DISTRIBUTION (g)	HIGH TENSION (h)	ELECTRIC PROPULSION (i)	LIGHTING (j)
RBC	81										
RBC	82										
RBC	83										
RBC	84										
RBC	85										
RBC	86										
RBC	87										
RBC	88										
RBC	89										
RBC	90										
RBC	91										
RBC	92										
RBC	93										
RBC	94										
RBC	95										
RBC	96										
RBC	97										
RBC	98										
RBC	99										
RBC	100										
E	1	**OPERATION & MAINTENANCE EXPENSE**									
E	2										
E	3	PRODUCTION EXPENSE									
E	4	Other Power Supply									
E	5	555 - Purchased Power - Capacity	ENERGY1	610,818	390,640	102,660	86,502	805	29,551	0	661
E	6	Total Other Power Supply		610,818	390,640	102,660	86,502	805	29,551	0	661
E	7	TOTAL PRODUCTION EXPENSE		610,818	390,640	102,660	86,502	805	29,551	0	661
E	8										
E	9	TRANSMISSION EXPENSES									
E	10	Operation Expense	DTRANR	172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
E	11	Maintenance Expense	DTRAN	0	0	0	0	0	0	0	0
E	12	TOTAL TRANSMISSION EXPENSE		172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
E	13										
E	14	DISTRIBUTION EXPENSES									
E	15	Operation									
E	16	580-Supervision	SALWAGDO	394	238	46	65	2	35	2	5
E	17	581-Load Dispatch	DISTPLT	46	23	6	10	0	6	0	1
E	18	582-Station Equipment	PLT_362	3,764	1,423	429	758	33	1,031	66	23
E	19	583-Overhead Lines	OHDIST	8,321	4,413	1,050	1,610	62	1,009	64	113
E	20	584-Underground Lines	UGDIST	7,521	3,764	914	1,423	55	1,196	76	94
E	21	585-Street Lighting	PLT_3713	0	0	0	0	0	0	0	0
E	22	586-Metering	CMETERS	10,978	8,012	1,154	1,509	43	256	4	0
E	23	587-Customer Installations	CUST	8,643	6,792	978	793	2	14	0	64
E	24	588-Miscellaneous	DISTPLT	52,563	26,273	6,335	10,922	332	7,176	452	1,073
E	25	589-Rents	DISTPLT	197	98	24	41	1	27	2	4
E	26	Total Distribution Operation		92,427	51,037	10,935	17,130	531	10,750	666	1,378
E	27										
E	28	Maintenance									

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
E	29	590-Supervision	SALWAGDM	0	0	0	0	0	0	0	0
E	30	591-Structures	PLT_361	7,342	2,776	837	1,479	65	2,011	128	46
E	31	592-Station Equipment	PLT_362	19,136	7,237	2,181	3,855	169	5,242	333	119
E	32	593-Overhead Lines	OHDIST	122,100	64,756	15,401	23,624	905	14,811	941	1,661
E	33	594-Underground Lines	UGDIST	34,939	17,484	4,246	6,610	257	5,554	353	436
E	34	595-Transformers	PLT_368	1,624	878	264	468	0	0	0	14
E	35	596-Street Lighting	PLT_373	1,830	0	0	0	0	0	0	1,830
E	36	597-Metering	CMETERS	0	0	0	0	0	0	0	0
E	37	598-Miscellaneous	DISTPLT	18,834	9,414	2,270	3,913	119	2,571	162	384
E	38	Total Distribution Maintenance		205,805	102,544	25,199	39,949	1,515	30,190	1,917	4,491
E	39										
E	40	TOTAL DISTRIBUTION PLANT O&M EXPENSES		298,232	153,581	36,134	57,079	2,046	40,940	2,583	5,868
E	41	TOTAL PURCHASED POWER O&M EXPENSES		610,818	390,640	102,660	86,502	805	29,551	0	661
E	42	TOTAL TRANSMISSION O&M EXPENSES		172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
E	43										
E	44	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		1,081,268	624,420	159,623	178,856	3,905	103,640	4,211	6,614
E	45										
E	46										
E	47										
E	48										
E	49										
E	50										
E	51	**OPERATION & MAINTENANCE EXPENSE CONTINUED**									
E	52										
E	53	CUSTOMER ACCOUNTS EXPENSES									
E	54	901-Supervision	SALWAGCA	0	0	0	0	0	0	0	0
E	55	902-Meter Reading	CMETERS	572	417	60	79	2	13	0	0
E	56	903-Customer Records and Collection Expen	CUSTREC	71,133	52,892	7,949	5,970	533	3,330	14	444
E	57	904-Uncollectible Accounts	EXP_904	36,723	26,801	6,075	2,997	38	806	0	5
E	58	905-Miscellaneous CA	CUSTCAM	8,557	6,724	968	785	2	14	0	64
E	59	TOTAL CUSTOMER ACCTS EXPENSE		116,985	86,835	15,053	9,831	576	4,163	15	512
E	60										
E	61										
E	62	CUSTOMER SERVICE EXPENSES									
E	63	907-Supervision	SALWAGCS	0	0	0	0	0	0	0	0
E	64	908-Customer Assistance	CUSTASST	11,028	8,627	1,299	381	19	663	28	10
E	65	909-Informational Advertisement	CUSTADVT	885	696	100	81	0	1	0	7
E	66	910-Miscellaneous CS	CUSTCSM	149	117	17	14	0	0	0	1
E	67	TOTAL CUSTOMER SERVICE EXPENSE		12,062	9,441	1,417	476	19	665	28	17
E	68										
E	69	SALES EXPENSES TOTAL (ACCT 912 & 916	CUSTSALES	883	694	100	81	0	1	0	7
E	70										
E	71	TOTAL OPER & MAINT EXCL A&G		1,211,198	721,389	176,192	189,244	4,500	108,469	4,253	7,150
E	72										
E	73	ADMINISTRATIVE & GENERAL EXPENSE									
E	74	920-Administrative Salaries	SALWAGES	40,687	24,062	4,833	6,339	280	4,448	249	476
E	75	921-Office Supplies & Expense	SALWAGES	8,660	5,122	1,029	1,349	60	947	53	101
E	76	923-Outside Service Employed	SALWAGES	78,835	46,621	9,364	12,283	542	8,618	483	923

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
E	77	924-Property Insurance	DGPLT	185	93	22	38	1	25	2	4
E	78	925-Injuries and Damages	SALWAGES	9,904	5,857	1,176	1,543	68	1,083	61	116
E	79	926-Employee Pensions & Benefits	SALWAGES	32,618	19,290	3,875	5,082	224	3,566	200	382
E	80	928-Regulatory Commission	CLAIMREV	12,684	7,265	1,708	2,134	62	1,326	66	124
E	81	929-Duplicate Charges-Credit	CLAIMREV	(1,496)	(857)	(201)	(252)	(7)	(156)	(8)	(15)
E	82	930-	CMETERS	0	0	0	0	0	0	0	0
E	83	930.2-Miscellaneous General	CLAIMREV	3,013	1,726	406	507	15	315	16	30
E	84	932-Maintenance of General Plant	GENLPLT	6,566	3,883	780	1,023	45	718	40	77
E	85	TOTAL A&G EXPENSE		191,655	113,060	22,991	30,047	1,289	20,889	1,161	2,219
E	86										
E	87	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPEN**		619,817	363,611	75,695	97,515	3,930	66,658	3,786	8,623
E	88										
E	89	**TOTAL OPERATION & MAINTENANCE EXPENSES**		1,402,854	834,450	199,183	219,291	5,789	129,358	5,414	9,368
E	90										
E	91										
E	92										
E	93										
E	94										
E	95										
E	96										
E	97										
E	98										
E	99										
E	100										
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**									
D	2										
D	3	INTANGIBLE PLANT EXPENSE	INTPLT	17,560	10,702	1,987	3,060	91	1,450	82	188
D	4										
D	5	TRANSMISSION PLANT EXPENSE	TRANPLT	0	0	0	0	0	0	0	0
D	6										
D	7	DISTRIBUTION PLANT EXPENSE									
D	8	360-Land & Land Rights	PLT_360	0	0	0	0	0	0	0	0
D	9	361-Structures & Improvements	PLT_361	2,955	1,118	337	595	26	810	51	18
D	10	362-Station Equipment	PLT_362	22,856	8,643	2,605	4,605	202	6,261	398	142
D	11	364-Poles,Towers & Fixtures	PLT_364	16,268	8,628	2,052	3,148	121	1,973	125	221
D	12	365-Overhead Conductors & Devices	PLT_365	29,247	15,511	3,689	5,659	217	3,548	226	398
D	13	366-Underground Conduit	PLT_366	7,807	3,907	949	1,477	57	1,241	79	97
D	14	367-Underground Conductors & Devices	PLT_367	30,539	15,282	3,711	5,777	225	4,854	309	381
D	15	368-Line Transformers	PLT_368	14,280	7,717	2,325	4,111	0	0	0	127
D	16	369-Services	PLT_369	8,672	4,849	698	3,061	9	54	0	0
D	17	370-Meters and AMR Amortization	PLT_370	32,014	23,365	3,365	4,401	126	746	11	0
D	18	371-Installation on Customer Premises	PLT_371	5	4	1	0	0	0	0	0
D	19	373-Street Lighting & Signal Systems	PLT_373	1,852	0	0	0	0	0	0	1,852
D	20	374-Asset Retirement Costs for Distribution P	DISTPLTXAR	0	0	0	0	0	0	0	0
D	21	TOTAL DISTRIBUTION PLANT EXPENSE		166,495	89,023	19,731	32,834	983	19,487	1,199	3,238
D	22										
D	23	GENERAL PLANT EXPENSE	GENLPLT	16,376	9,684	1,945	2,551	113	1,790	100	192
D	24										

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	RESIDENTIAL (d)	RESIDENTIAL HEATING (e)	GENERAL SERVICE (f)	PRIMARY DISTRIBUTION (g)	HIGH TENSION (h)	ELECTRIC PROPULSION (i)	LIGHTING (j)
D	25	COMMON PLANT DEPRECIATION/AMORTIZ	SALWAGES	34,633	20,481	4,114	5,396	238	3,786	212	405
D	26										
D	27										
D	28	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		235,063	129,891	27,778	43,842	1,425	26,513	1,593	4,022
D	29										
D	30										
D	31										
D	32										
D	33										
D	34										
D	35										
D	36										
D	37										
D	38										
D	39										
D	40										
D	41										
D	42										
D	43										
D	44										
D	45										
D	46										
D	47										
D	48										
D	49										
D	50										
TO	1	**OTHER OPERATING EXPENSES**									
TO	2										
TO	3	**TAXES OTHER THAN INCOME TAXES**									
TO	4	**General Taxes**									
TO	5	PURTA Taxes	PLT_3601	5,286	1,999	602	1,065	47	1,448	92	33
TO	6	Capital Stock	CAPSTOCK	0	0	0	0	0	0	0	0
TO	7	Payroll Related	SALWAGES	10,564	6,247	1,255	1,646	73	1,155	65	124
TO	8	PA & Local Use Tax	CLAIMREV	350	201	47	59	2	37	2	3
TO	9	PA Property Tax	TOTPLT	4,357	2,203	524	894	27	585	37	87
TO	10	PA Corporate LoanTax	TOTPLT	0	0	0	0	0	0	0	0
TO	11	Total General Taxes		20,557	10,650	2,429	3,664	149	3,225	195	247
TO	12										
TO	13										
TO	14	**Gross Receipt Tax**									
TO	15										
TO	16	Purchased Power									
TO	17	Retail Revenue	CALCULATED	653,769	418,108	109,879	92,584	862	31,629	0	708
TO	18	Forfeited Discounts		0							
TO	19	Less: Bad Debt		0							
TO	20	Total Purchased Power Revenue	CALCULATED	653,769	418,108	109,879	92,584	862	31,629	0	708
TO	21	Total Purchased Power @ GRT Rate 5.90%	CALCULATED	38,572	24,668	6,483	5,462	51	1,866	0	42
TO	22										

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	RESIDENTIAL (d)	RESIDENTIAL HEATING (e)	GENERAL SERVICE (f)	PRIMARY DISTRIBUTION (g)	HIGH TENSION (h)	ELECTRIC PROPULSION (i)	LIGHTING (j)
TO	23	Transmission									
TO	24	Retail Revenue	CALCULATED	185,615	86,438	22,449	38,019	1,136	35,728	1,754	91
TO	25	Forfeited Discounts		0							
TO	26	Less: Bad Debt		0							
TO	27	Total Transmission Revenue	CALCULATED	185,615	86,438	22,449	38,019	1,136	35,728	1,754	91
TO	28	Total Transmission @ GRT Rate 5.90%	CALCULATED	10,951	5,100	1,324	2,243	67	2,108	104	5
TO	29										
TO	30	Distribution									
TO	31	Retail Revenue		1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
TO	32	Forfeited Discounts	CALCULATED	9,406	6,865	1,556	768	10	206	0	1
TO	33	Less: Bad Debt	CALCULATED	36,723	26,801	6,075	2,997	38	806	0	5
TO	34	Total Distribution Revenue	CALCULATED	1,197,258	661,139	131,915	222,621	8,150	146,155	7,207	20,072
TO	35	Total Distribution @ GRT Rate 5.90%	CALCULATED	70,638	39,007	7,783	13,135	481	8,623	425	1,184
TO	36										
TO	37	Total Gross Receipts Tax		120,162	68,775	15,590	20,840	599	12,597	529	1,231
TO	38										
TO	39	TOTAL PURCHASED POWER TOIT EXPENSES		38,572	24,668	6,483	5,462	51	1,866	0	42
TO	40	TOTAL TRANSMISSION TOIT EXPENSES		10,951	5,100	1,324	2,243	67	2,108	104	5
TO	41	TOTAL DISTRIBUTION TOIT EXPENSES		91,196	49,657	10,211	16,799	629	11,848	620	1,431
TO	42										
TO	43	**TOTAL TAXES OTHER THAN INCOME**		140,719	79,425	18,019	24,504	747	15,822	724	1,478
TO	44										
TO	45										
TO	46										
TO	47										
TO	48										
TO	49										
TO	50										
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**									
TI	2										
TI	3	TOTAL DISTRIBUTION OPERATING REVENUES		1,258,261	701,465	141,202	230,378	8,343	148,996	7,368	20,508
TI	4	LESS:									
TI	5	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	619,817	363,611	75,695	97,515	3,930	66,658	3,786	8,623
TI	6	DEPRECIATION AND AMORTIZATION EXP	CALCULATED	235,063	129,891	27,778	43,842	1,425	26,513	1,593	4,022
TI	7	TAXES OTHER THAN INCOME TAXES	CALCULATED	91,196	49,657	10,211	16,799	629	11,848	620	1,431
TI	8	NET OPERATING INCOME BEFORE TAXES		312,185	158,307	27,518	72,223	2,359	43,978	1,368	6,432
TI	9	LESS:									
TI	10	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of D		93,491	48,480	11,341	18,312	611	12,462	763	1,521
TI	11										
TI	12	**BASE TAXABLE DISTRIBUTION INCOME**		218,695	109,826	16,177	53,911	1,747	31,516	606	4,912
TI	13										
TI	14										
TI	15	**CALCULATION OF PA STATE INCOME TAXES**									
TI	16	BASE TAXABLE INCOME	CALCULATED	218,695	109,826	16,177	53,911	1,747	31,516	606	4,912
TI	17	LESS:									
TI	18	State Tax Depreciation (Over) Under Book	TOTPLT	(19,825)	(10,022)	(2,385)	(4,069)	(125)	(2,663)	(167)	(394)
TI	19	Other Adjustment	TOTPLT	38,056	19,238	4,578	7,811	240	5,111	320	757
TI	20	Repair Allowance Deduction	TOTPLT	96,900	48,986	11,656	19,889	611	13,015	816	1,927

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
TI	21	PA STATE TAXALBE DISTRIBUTION INCOME		103,564	51,625	2,328	30,279	1,022	16,052	(364)	2,622
TI	22	**PA STATE INCOME TAXES @ Tax Rate 9.99%**		10,346	5,157	233	3,025	102	1,604	(36)	262
TI	23										
TI	24			0							
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**									
TI	26	BASE TAXABLE INCOME	CALCULATED	218,695	109,826	16,177	53,911	1,747	31,516	606	4,912
TI	27	LESS:									
TI	28	PA State Income Taxes		10,346	5,157	233	3,025	102	1,604	(36)	262
TI	29	Federal Tax Depreciation (Over) Under Book	TOTPLT	(76,499)	(38,672)	(9,202)	(15,702)	(482)	(10,275)	(644)	(1,522)
TI	30	Other Adjustment	TOTPLT	38,056	19,238	4,578	7,811	240	5,111	320	757
TI	31	Repair Allowance Deduction	TOTPLT	96,900	48,986	11,656	19,889	611	13,015	816	1,927
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME		149,891	75,117	8,913	38,887	1,277	22,061	150	3,487
TI	33	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		31,477	15,775	1,872	8,166	268	4,633	31	732
TI	34										
TI	35	**PLUS:**									
TI	36	**DEFERRED FEDERAL INCOME TAXES**									
TI	37	Federal Accelerated Depreciation (Over) Und	TOTPLT	(35,189)	(17,789)	(4,233)	(7,223)	(222)	(4,726)	(296)	(700)
TI	38	**DEFERRED FEDERAL INCOME TAXES @ Tax Rate 21.00%**		(7,390)	(3,736)	(889)	(1,517)	(47)	(993)	(62)	(147)
TI	39										
TI	40	**LESS:**									
TI	41	**OTHER TAX ADJUSTMENTS**									
TI	42	Electric Plant	TOTPLT	16	8	2	3	0	2	0	0
TI	43	Common Plant	SALWAGES	12	7	1	2	0	1	0	0
TI	44	Consolidated Income Tax Adjustment	EBT	0	0	0	0	0	0	0	0
TI	45	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**		24,059	12,024	979	6,644	221	3,637	(31)	585
TI	46										
TI	47	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**		34,406	17,181	1,212	9,669	323	5,240	(67)	847
TI	48										
TI	49										
TI	50										
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**									
TI	52										
TI	53	**DEVELOPMENT OF PURCHASED POWER TAXES**									
TI	54	PURCHASED POWER OPERATING REVENI	CALCULATED	653,769	418,108	109,879	92,584	862	31,629	0	708
TI	55	LESS:									
TI	56	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	610,818	390,640	102,660	86,502	805	29,551	0	661
TI	57	TAXES OTHER THAN INCOME TAXES	CALCULATED	38,572	24,668	6,483	5,462	51	1,866	0	42
TI	58	NET OPERATING INCOME BEFORE TAXES		4,379	2,800	736	620	6	212	0	5
TI	59	LESS:									
TI	60	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of D		381	243	64	54	1	18	0	0
TI	61	**BASE TAXABLE PURCHASED POWER INCOME**		3,998	2,557	672	566	5	193	0	4
TI	62	LESS:									
TI	63	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate**		399	255	67	57	1	19	0	0
TI	64	EQUALS:									
TI	65	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate**		756	483	127	107	1	37	0	1
TI	66	Additional Purchase Power Expense NOL		0	0	0	0	0	0	0	0
TI	67										
TI	68	**DEVELOPMENT OF TRANSMISSION TAXES**									

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
TI	69	TRANSMISSION OPERATING REVENUES	CALCULATED	185,615	86,438	22,449	38,019	1,136	35,728	1,754	91
TI	70	LESS:									
TI	71	OPERATION & MAINTAINENCE EXPENSE	CALCULATED	172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
TI	72	TAXES OTHER THAN INCOME TAXES	CALCULATED	10,951	5,100	1,324	2,243	67	2,108	104	5
TI	73	NET OPERATING INCOME BEFORE TAXES		2,445	1,139	296	501	15	471	23	1
TI	74	LESS:									
TI	75	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of D		119	52	7	23	1	34	1	0
TI	76	**BASE TAXABLE TRANSMISSION INCOME**		2,326	1,087	288	478	14	436	22	1
TI	77	LESS:									
TI	78	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate**		232	109	29	48	1	44	2	0
TI	79	EQUALS:									
TI	80	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate**		440	205	54	90	3	82	4	0
TI	81										
TI	82	**TOTAL PA INCOME TAX EXPENSE**		10,978	5,521	328	3,129	104	1,667	(34)	262
TI	83	**TOTAL FEDERAL INCOME TAX EXPENSE**		25,255	12,712	1,161	6,842	225	3,756	(27)	586
TI	84	**TOTAL INCOME TAX EXPENSE**		36,233	18,234	1,489	9,971	329	5,422	(61)	848
TI	85										
TI	86										
TI	87										
TI	88										
TI	89	**TAX RATES**									
TI	90	GROSS RECEIPTS TAX RATE	5.90%								
TI	91	STATE TAX RATE	9.99%								
TI	92	UNCOLLECTIBLE EXPENSES	0.00886								
TI	93	FEDERAL TAX RATE - CURRENT	21.00%								
TI	94	PUC / OCA & SBA ASSESSMENT RATE	0.0036								
TI	95	EFFECTIVE TAX RATE	28.8921%								
TI	96	LPC RATE	0.004319								
TI	97	GROSS REVENUE CONVERSION FACTOR	1.507458								
TI	98	**WEIGHTED COST OF DEBT**	1.9395%								
TI	99										
TI	100										
SW	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**									
SW	2										
SW	3	**PRODUCTION OTHER SALARIES & WAGES EXPENSE**									
SW	4	555-Purchased Power	OX_PROD	0	0	0	0	0	0	0	0
SW	5	TOTAL PRODUCTION OTHER SAL & WAG EXP		0	0	0	0	0	0	0	0
SW	6										
SW	7	**TRANSMISSION SALARIES & WAGES EXPENSE**									
SW	8	Operation	OX_TRAN	0	0	0	0	0	0	0	0
SW	9	Maintenance	MX_TRAN	0	0	0	0	0	0	0	0
SW	10	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0
SW	11										
SW	12	**DISTRIBUTION SALARIES & WAGES EXPENSE**									
SW	13	Operation									
SW	14	583-Overhead Lines	OX_583	1,543	819	195	299	11	187	12	21
SW	15	584-Underground Lines	OX_584	2,041	1,021	248	386	15	324	21	25
SW	16	586-Metering	OX_586	2,111	1,540	222	290	8	49	1	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
SW	17	587-Customer Installations	OX_587	4,194	3,296	475	385	1	7	0	31
SW	18	588-Miscellaneous	OX_588	6,545	3,271	789	1,360	41	894	56	134
SW	19	Total Operation		16,433	9,947	1,928	2,719	77	1,461	90	211
SW	20	Maintenance									
SW	21	591-Structures	MX_591	1,232	466	140	248	11	337	21	8
SW	22	592-Station Equipment	MX_592	5,859	2,216	668	1,180	52	1,605	102	36
SW	23	593-Overhead Lines	MX_593	29,733	15,769	3,750	5,753	220	3,607	229	405
SW	24	594-Underground Lines	MX_594	14,345	7,178	1,743	2,714	106	2,280	145	179
SW	25	595-Transformers	MX_595	293	158	48	84	0	0	0	3
SW	26	596-Street Lighting	MX_596	99	0	0	0	0	0	0	99
SW	27	598-Miscellaneous	MX_598	3,616	1,808	436	751	23	494	31	74
SW	28	Total Maintenance		55,177	27,594	6,785	10,731	411	8,323	529	804
SW	29	TOTAL DISTRIBUTION		71,610	37,541	8,713	13,450	489	9,784	618	1,015
SW	30										
SW	31	**CUSTOMER ACCOUNTS SAL & WAGES EXP**									
SW	32	903-Customer Records and Collection Expen	CUSTREC	28,416	21,129	3,175	2,385	213	1,330	6	177
SW	33	905-Miscellaneous CA	CUSTCAM	918	721	104	84	0	1	0	7
SW	34	**TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP**		29,334	21,851	3,279	2,469	213	1,332	6	184
SW	35										
SW	36	**CUSTOMER SERVICE SAL & WAGES EXP**									
SW	37	908-Customer Assistance	CUSTASST	1,213	949	143	42	2	73	3	1
SW	38	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0
SW	39	910-Miscellaneous CS	CUSTCSM	7	5	1	1	0	0	0	0
SW	40	TOTAL CUSTOMER SERVICE SAL & WAGES EXP		1,219	954	144	43	2	73	3	1
SW	41										
SW	42	**SALES EXPENSE (ACCT 912&916)**	OX_CS	537	420	63	21	1	30	1	1
SW	43										
SW	44	**ADMINISTRATIVE & GENERAL SALARIES &**	SALWAGXAG	44,085	26,040	5,237	6,888	304	4,828	271	518
SW	45	**TOT OPER & MAINTENANCE LABOR**		146,785	86,806	17,436	22,870	1,009	16,047	899	1,719
SW	46										
SW	47										
SW	48										
SW	49										
SW	50										
AF	1	**ALLOCATION FACTOR TABLE**									
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	3										
AF	4	**DEMAND**									
AF	5	DEMAND - PRODUCTION RELATED									
AF	6	Demand Production	DPROD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AF	7										
AF	8										
AF	9										
AF	10										
AF	11	DEMAND - TRANSMISSION RELATED									
AF	12	Demand Transmission (1 Coincident Peak)	DTRAN	8,141,078	3,547,555	512,386	1,546,608	72,427	2,356,885	99,550	5,668
AF	13										
AF	14	Demand Transmission (Revenue)	DTRANR	185,615	86,438	22,449	38,019	1,136	35,728	1,754	91

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AF	15										
AF	16										
AF	17										
AF	18										
AF	19										
AF	20	DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand)									
AF	21	Demand Distribution Primary High Tension	DDISPHT	9,380,936	3,547,555	1,069,010	1,889,922	83,086	2,569,692	163,341	58,330
AF	22	Demand Distribution Primary Overhead Lines	DDISTPOL	6,647,903	3,547,555	1,069,010	1,889,922	83,086	0	0	58,330
AF	23	Demand Distribution Primary Underground Lin	DDISTPUL	6,647,903	3,547,555	1,069,010	1,889,922	83,086	0	0	58,330
AF	24										
AF	25	Demand Distribution Secondary Overhead Line	DDISTSOL	6,564,817	3,547,555	1,069,010	1,889,922	0	0	0	58,330
AF	26	Demand Distribution Secondary Underground I	DDISTSUL	6,564,817	3,547,555	1,069,010	1,889,922	0	0	0	58,330
AF	27	Demand Distribution Overhead Line Transform	DDISTSOT	6,564,817	3,547,555	1,069,010	1,889,922	0	0	0	58,330
AF	28	Demand Distribution Undergrnd Line Transforn	DDISTSUT	6,564,817	3,547,555	1,069,010	1,889,922	0	0	0	58,330
AF	29										
AF	30										
AF	31										
AF	32										
AF	33										
AF	34										
AF	35										
AF	36										
AF	37										
AF	38										
AF	39										
AF	40										
AF	41										
AF	42										
AF	43										
AF	44										
AF	45										
AF	46										
AF	47										
AF	48										
AF	49										
AF	50										
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	53										
AF	54	**ENERGY**									
AF	55	Energy Revenue at pro-forma adjusted level	ENERGY1	653,769	418,108	109,879	92,584	862	31,629	0	708
AF	56	Energy @ Meter MWh Sales)	ENERGY2	37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
AF	57										
AF	58										
AF	59										
AF	60										
AF	61										
AF	62										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AF	63										
AF	64										
AF	65	**CUSTOMER**									
AF	66	364 & 365 - Cust. Dist. Secondary OH Lines (N	CDISTSOL	6,564,817	3,547,555	1,069,010	1,889,922	0	0	0	58,330
AF	67	366 & 367 - Cust. Dist. Secondary UG Lines (N	CDISTSUL	6,564,817	3,547,555	1,069,010	1,889,922	0	0	0	58,330
AF	66	364 & 366 - Cust. Dist. Secondary Poles, Towe	CDISTSOLC	1,690,712	1,300,575	187,297	151,768	0	0	0	51,073
AF	67	365 & 367 - Cust. Dist. Secondary Conductors	CDISTSULC	1,690,712	1,300,575	187,297	151,768	0	0	0	51,073
AF	68				231	33	44	1	7	0	0
AF	69	369-Services	CSERVICE	5,159,430	2,885,140	415,492	1,821,461	5,401	31,936	0	0
AF	70	370-Meters	CMETERS	316,854	231,254	33,303	43,557	1,249	7,384	108	0
AF	71	371-Installation on Customer Premises	CUSTPREM	1,690,712	1,300,575	187,297	151,768	0	0	0	51,073
AF	72	373-Street Lighting & Signal Systems	CLIGHT	1	0	0	0	0	0	0	1
AF	73										
AF	74	Customer Deposits	CUSTDEP	1.0000	0.3342	0.0758	0.5273	0.0028	0.0598	0.0000	0.0000
AF	75										
AF	76										
AF	77	903-Customer Records and Collections	CUSTREC	1.0000	0.7436	0.1117	0.0839	0.0075	0.0468	0.0002	0.0062
AF	78	905-Miscellaneous Customer Accounts	CUSTCAM	1,655,077	1,300,575	187,297	151,768	450	2,661	39	12,288
AF	79	908-Customer Assistance	CUSTASST	1.0000	0.7824	0.1178	0.0346	0.0017	0.0601	0.0025	0.0009
AF	80	909-Informational and Instructional Advertising	CUSTADVT	1,655,077	1,300,575	187,297	151,768	450	2,661	39	12,288
AF	81	910-Miscellaneous Customer Service	CUSTCSM	1,655,077	1,300,575	187,297	151,768	450	2,661	39	12,288
AF	82	916-Miscellaneous Sales Expense	CUSTSALES	1,655,077	1,300,575	187,297	151,768	450	2,661	39	12,288
AF	83										
AF	84	Number of Bills	CUSTBILLS	19,860,923	15,606,895	2,247,564	1,821,211	5,400	31,932	465	147,456
AF	85	Number of Customers	CUST	1,655,077	1,300,575	187,297	151,768	450	2,661	39	12,288
AF	86	Number of Residential Customers	CUSTRES	1,487,872	1,300,575	187,297	0	0	0	0	0
AF	87										
AF	90										
AF	91										
AF	92										
AF	93										
AF	94										
AF	95										
AF	96										
AF	97										
AF	98										
AF	99										
AF	100										
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	103										
AF	104	**Plant Related**									
AF	105	Intangible Plant	INTPLT	175,650	107,054	19,880	30,610	910	14,501	818	1,877
AF	106	Transmission Plant in Service	TRANPLT	0	0	0	0	0	0	0	0
AF	107	Distribution Plant in Service	DISTPLT	6,781,042	3,389,420	817,306	1,409,010	42,798	925,789	58,280	138,437
AF	108	General Plant in Service	GENLPLT	236,936	140,120	28,145	36,917	1,628	25,902	1,451	2,774
AF	109	Total Electric Plant In Service	TOTPLT	7,193,628	3,636,594	865,331	1,476,537	45,337	966,192	60,550	143,088
AF	110										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
AF	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	6,779,149	3,388,474	817,078	1,408,616	42,786	925,531	58,264	138,399
AF	112	Total Transmission and Distribution Plant	TDPLT	6,781,042	3,389,420	817,306	1,409,010	42,798	925,789	58,280	138,437
AF	113	Total Distribution and General Plant	DGPLT	7,017,978	3,529,540	845,451	1,445,926	44,427	951,691	59,732	141,211
AF	114	Rate Base	RATEBASE	4,846,186	2,514,903	588,432	948,146	31,599	645,266	39,406	78,435
AF	115										
AF	116	Account 360	PLT_360	42,884	16,217	4,887	8,640	380	11,747	747	267
AF	117	Account 361	PLT_361	139,261	52,664	15,870	28,056	1,233	38,147	2,425	866
AF	118	Account 362	PLT_362	1,163,133	439,858	132,546	234,330	10,302	318,614	20,253	7,232
AF	119	Account 364	PLT_364	754,022	399,895	95,111	145,891	5,586	91,466	5,814	10,259
AF	120	Account 365	PLT_365	1,341,927	711,690	169,269	259,641	9,941	162,781	10,347	18,259
AF	121	Account 366	PLT_366	464,223	232,300	56,411	87,818	3,418	73,794	4,691	5,791
AF	122	Account 367	PLT_367	1,372,757	686,937	166,814	259,688	10,106	218,216	13,871	17,126
AF	123	Account 368	PLT_368	634,209	342,720	103,274	182,580	0	0	0	5,635
AF	124	Account 369	PLT_369	433,534	242,431	34,913	153,053	454	2,684	0	0
AF	125	Account 370	PLT_370	346,878	253,168	36,459	47,684	1,367	8,083	118	0
AF	126	Account 371	PLT_371	13,772	10,594	1,526	1,236	0	0	0	416
AF	127	Account 373	PLT_373	72,548	0	0	0	0	0	0	72,548
AF	128	Distribution Overhead Plant in Service	OHDIST	2,095,949	1,111,585	264,380	405,532	15,527	254,246	16,161	28,518
AF	129	Distribution Underground Plant in Service	UGDIST	1,836,980	919,238	223,225	347,506	13,524	292,010	18,561	22,917
AF	130	Accounts 360 & 361	PLT_3601	182,145	68,881	20,756	36,696	1,613	49,894	3,172	1,133
AF	131	Accounts 371 & 373	PLT_3713	86,320	10,594	1,526	1,236	0	0	0	72,964
AF	132										
AF	133	Residential	DPLTRES	2,030,823	2,030,823	0	0	0	0	0	0
AF	134	Residential Heating	DPLTRH	487,605	0	487,605	0	0	0	0	0
AF	135	General Service	DPLTGS	753,038	0	0	753,038	0	0	0	0
AF	136	Primary Distribution	DPLTPRID	29,051	0	0	0	29,051	0	0	0
AF	137	High Tension	DPLTHT	546,256	0	0	0	0	546,256	0	0
AF	138	Electric Propulsion	DPLTEP	34,722	0	0	0	0	0	34,722	0
AF	139	Lighting	DPLTLCUST	51,435	0	0	0	0	0	0	51,435
AF	140										
AF	141										
AF	142										
AF	143										
AF	144										
AF	145										
AF	146										
AF	147										
AF	148										
AF	149										
AF	150										
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	153										
AF	154	**Production Expense Related**									
AF	155	Account 555	OX_555	610,818	390,640	102,660	86,502	805	29,551	0	661
AF	156	O&M Expense Production Other	OX_PROD	610,818	390,640	102,660	86,502	805	29,551	0	661
AF	157	Salaries and Wages Production Operation	SALWAGPO	0	0	0	0	0	0	0	0
AF	158										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AF	159										
AF	160	**Transmission Expense Related**									
AF	161	Transmission Operation Expense	OX_TRAN	172,218	80,200	20,829	35,275	1,054	33,149	1,628	84
AF	162	Transmission Maintenance Expense	MX_TRAN	0	0	0	0	0	0	0	0
AF	163	Transmission Salaries & Wages Accounts 511	SALWAGTO	0	0	0	0	0	0	0	0
AF	164	Transmission Salaries & Wages Accounts 569	SALWAGTM	0	0	0	0	0	0	0	0
AF	165										
AF	166										
AF	167	**Distribution Expense Related**									
AF	168	Account 580	OX_580	394	238	46	65	2	35	2	5
AF	169	Account 581	OX_581	46	23	6	10	0	6	0	1
AF	170	Account 582	OX_582	3,764	1,423	429	758	33	1,031	66	23
AF	171	Account 583	OX_583	8,321	4,413	1,050	1,610	62	1,009	64	113
AF	172	Account 584	OX_584	7,521	3,764	914	1,423	55	1,196	76	94
AF	173	Account 585	OX_585	0	0	0	0	0	0	0	0
AF	174	Account 586	OX_586	10,978	8,012	1,154	1,509	43	256	4	0
AF	175	Account 587	OX_587	8,643	6,792	978	793	2	14	0	64
AF	176	Account 588	OX_588	52,563	26,273	6,335	10,922	332	7,176	452	1,073
AF	177	Account 589	OX_589	197	98	24	41	1	27	2	4
AF	178	Account 591	MX_591	7,342	2,776	837	1,479	65	2,011	128	46
AF	179	Account 592	MX_592	19,136	7,237	2,181	3,855	169	5,242	333	119
AF	180	Account 593	MX_593	122,100	64,756	15,401	23,624	905	14,811	941	1,661
AF	181	Account 594	MX_594	34,939	17,484	4,246	6,610	257	5,554	353	436
AF	182	Account 595	MX_595	1,624	878	264	468	0	0	0	14
AF	183	Account 596	MX_596	1,830	0	0	0	0	0	0	1,830
AF	184	Account 597	MX_597	0	0	0	0	0	0	0	0
AF	185	Account 598	MX_598	18,834	9,414	2,270	3,913	119	2,571	162	384
AF	186	O&M Accounts 581-589	OX_DIST	92,033	50,798	10,889	17,065	529	10,715	663	1,373
AF	187	O&M Accounts 591-598	MX_DIST	205,805	102,544	25,199	39,949	1,515	30,190	1,917	4,491
AF	188										
AF	189										
AF	190										
AF	191										
AF	192										
AF	193										
AF	194										
AF	195										
AF	196										
AF	197										
AF	198										
AF	199										
AF	200										
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**									
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AF	203										
AF	204	**Customer Distribution Expense Related**									
AF	205	Account 902	OX_902	572	417	60	79	2	13	0	0
AF	206	Account 903	OX_903	71,133	52,892	7,949	5,970	533	3,330	14	444

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
AF	207	Account 904	OX_904	36,723	26,801	6,075	2,997	38	806	0	5
AF	208	O&M Accounts 902-905	OX_CA	116,985	86,835	15,053	9,831	576	4,163	15	512
AF	209										
AF	210	Account908	OX_908	11,028	8,627	1,299	381	19	663	28	10
AF	211	Account909	OX_909	885	696	100	81	0	1	0	7
AF	212	Account910	OX_910	149	117	17	14	0	0	0	1
AF	213	O&M Accounts 908-910	OX_CS	12,062	9,441	1,417	476	19	665	28	17
AF	214	Accounts 901-910	X_CACS	129,047	96,276	16,469	10,307	595	4,828	43	529
AF	215										
AF	216	Total O&M less Purchased Power	OMXPP	791,152	443,116	96,423	132,709	4,984	99,805	5,414	8,701
AF	217	Total O&M less PP less Payroll less Pension	OMXPPPP	611,750	337,021	75,113	104,756	3,751	80,193	4,315	6,600
AF	218										
AF	219	**Salaries and Wages Expense Related**									
AF	220	Salaries & Wages Accounts 581-589	SALWAGDO	16,433	9,947	1,928	2,719	77	1,461	90	211
AF	221	Salaries & Wages Accounts 591-598	SALWAGDM	55,177	27,594	6,785	10,731	411	8,323	529	804
AF	222	Salaries & Wages Accounts 902-905	SALWAGCA	29,334	21,851	3,279	2,469	213	1,332	6	184
AF	223	Salaries & Wages Accounts 908-910	SALWAGCS	1,219	954	144	43	2	73	3	1
AF	224	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	102,164	60,346	12,136	15,962	704	11,189	627	1,200
AF	225	Total Salaries and Wages Expense	SALWAGES	146,785	86,806	17,436	22,870	1,009	16,047	899	1,719
AF	226										
AF	227	Base Taxable Income	EBT	218,695	109,826	16,177	53,911	1,747	31,516	606	4,912
AF	228										
AF	229										
AF	230										
AF	231										
AF	232										
AF	233										
AF	234										
AF	235										
AF	236										
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AF	243										
AF	244										
AF	245										
AF	246										
AF	247										
AF	248										
AF	249										
AF	250										
AF	251	**REVENUES AND BILLING DETERMINANTS**									
AF	252										
AF	253	Base Rate Sales Revenue	SALESREV	1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
AF	254										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AF	255	Residential	SREVRES	681,075	681,075	0	0	0	0	0	0
AF	256	Residential Heating	SREVRH	136,434	0	136,434	0	0	0	0	0
AF	257	General Service	SREVGS	224,851	0	0	224,851	0	0	0	0
AF	258	Primary Distribution	SREVPRID	8,178	0	0	0	8,178	0	0	0
AF	259	High Tension	SREVHT	146,754	0	0	0	0	146,754	0	0
AF	260	Electric Propulsion	SREVEP	7,207	0	0	0	0	0	7,207	0
AF	261	Lighting	SREVLCUST	20,075	0	0	0	0	0	0	20,075
AF	262										
AF	263										
AF	264										
AF	265										
AF	266	Claimed Rate Sales Revenue	CLAIMREV	2,206,473	1,263,699	297,033	371,204	10,793	230,695	11,396	21,653
AF	267										
AF	268	Capital Stock	CAPSTOCK	4,700,051	2,450,147	581,182	923,870	28,065	598,444	35,973	82,370
AF	269										
AF	270										
AF	271										
AF	272	**PRESENT REVENUES/EXPENSES FROM SALES INPUT**									
AF	273										
AF	274	Total Sales of Electricity Revenues		1,220,714	679,991	136,154	224,019	8,136	145,219	7,142	20,054
AF	275	Sales of Electricity Revenues - Distribution		1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
AF	276	Sales of Electricity Revenues - Nuclear Decommissioning		(3,860)	(1,085)	(281)	(832)	(42)	(1,535)	(65)	(21)
AF	277										
AF	278										
AF	279										
AF	280	Sales of Electricity Revenues - Transmission		185,615	86,438	22,449	38,019	1,136	35,728	1,754	91
AF	281										
AF	282										
AF	283	**BILLING DETERMINATE INPUTS**									
AF	284	Number of Customer Bills	CALCULATED	19,860,923	15,606,895	2,247,564	1,821,211	5,400	31,932	465	147,456
AF	285	Annual MWh Sales @ Meter	CALCULATED	37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
AF	286	Annual MW - Billed		63,105	0	0	26,760	1,043	33,557	1,746	0
AF	287										
AF	288										
AF	289	**RATE OF RETURN**									
AF	290	Rate of Return (Equalized)	CALCULATED	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
AF	291										
AF	292										
AF	293										
AF	294										
AF	295										
AF	296										
AF	297										
AF	298										
AF	299										
AF	300										
AP	1	**ALLOCATION PROPORTIONS TABLE**									
AP	2	**EXTERNALLY DEVELOPED ALLOCATION F**									

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AP	3										
AP	4										
AP	5	DEMAND - PRODUCTION RELATED									
AP	6	Demand Production	DPROD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	7										
AP	8										
AP	9										
AP	10										
AP	11	DEMAND - TRANSMISSION RELATED									
AP	12	Demand Transmission (1 Coincident Peak)	DTRAN	1.00000	0.43576	0.06294	0.18998	0.00890	0.28951	0.01223	0.00070
AP	13										
AP	14	Demand Transmission (Revenue)	DTRANR	1.00000	0.46569	0.12094	0.20483	0.00612	0.19248	0.00945	0.00049
AP	15										
AP	16										
AP	17										
AP	18										
AP	19										
AP	20	DEMAND - DISTRIBUTION RELATED (Non-C									
AP	21	Demand Distribution Primary High Tension	DDISPHT	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	22	Demand Distribution Primary Overhead Lines	DDISTPOL	1.00000	0.53364	0.16080	0.28429	0.01250	0.00000	0.00000	0.00877
AP	23	Demand Distribution Primary Underground Lin	DDISTPUL	1.00000	0.53364	0.16080	0.28429	0.01250	0.00000	0.00000	0.00877
AP	24										
AP	25	Demand Distribution Secondary Overhead Lin	DDISTSOL	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	26	Demand Distribution Secondary Underground I	DDISTSUL	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	27	Demand Distribution Overhead Line Transform	DDISTSOT	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	28	Demand Distribution Undergrnd Line Transforn	DDISTSUT	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	29										
AP	30										
AP	31										
AP	32										
AP	33										
AP	34										
AP	35										
AP	36										
AP	37										
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AP	49										
AP	50										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	53										
AP	54	**ENERGY**									
AP	55	Energy Revenue at pro-forma adjusted level	ENERGY1	1.00000	0.63953	0.16807	0.14162	0.00132	0.04838	0.00000	0.00108
AP	56	Energy @ Meter MWh Sales)	ENERGY2	1.00000	0.28102	0.07270	0.21557	0.01083	0.39773	0.01671	0.00544
AP	57										
AP	58										
AP	59										
AP	60										
AP	61										
AP	62										
AP	63										
AP	64										
AP	65	**CUSTOMER**									
AP	66	364 & 365 - Cust. Dist. Secondary OH Lines (N	CDISTSOL	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	67	366 & 367 - Cust. Dist. Secondary UG Lines (N	CDISTSUL	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	66	364 & 366 - Cust. Dist. Secondary Poles, Towe	CDISTSOLC	1.00000	0.76925	0.11078	0.08977	0.00000	0.00000	0.00000	0.03021
AP	67	365 & 367 - Cust. Dist. Secondary Conductors	CDISTSULC	1.00000	0.76925	0.11078	0.08977	0.00000	0.00000	0.00000	0.03021
AP	68										
AP	69	369-Services	CSERVICE	1.00000	0.55920	0.08053	0.35304	0.00105	0.00619	0.00000	0.00000
AP	70	370-Meters	CMETERS	1.00000	0.72985	0.10511	0.13747	0.00394	0.02330	0.00034	0.00000
AP	71	371-Installation on Customer Premises	CUSTPREM	1.00000	0.76925	0.11078	0.08977	0.00000	0.00000	0.00000	0.03021
AP	72	373-Street Lighting & Signal Systems	CLIGHT	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	73										
AP	74	Customer Deposits	CUSTDEP	1.00000	0.33424	0.07577	0.52732	0.00284	0.05984	0.00000	0.00000
AP	75										
AP	76										
AP	77	903-Customer Records and Collections	CUSTREC	1.00000	0.74357	0.11175	0.08393	0.00749	0.04681	0.00020	0.00624
AP	78	905-Miscellaneous Customer Accounts	CUSTCAM	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	79	908-Customer Assistance	CUSTASST	1.00000	0.78236	0.11784	0.03457	0.00171	0.06012	0.00253	0.00087
AP	80	909-Informational and Instructional Advertising	CUSTADVT	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	81	910-Miscellaneous Customer Service	CUSTCSM	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	82	916-Miscellaneous Sales Expense	CUSTSALES	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	83										
AP	84	Number of Bills	CUSTBILLS	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	85	Number of Customers	CUST	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	86	Number of Residential Customers	CUSTRES	1.00000	0.87412	0.12588	0.00000	0.00000	0.00000	0.00000	0.00000
AP	87										
AP	90										
AP	91										
AP	92										
AP	93										
AP	94										
AP	95										
AP	96										
AP	97										
AP	98										

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
AP	99										
AP	100										
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	103										
AP	104	**Plant Related**									
AP	105	Intangible Plant	INTPLT	1.00000	0.60947	0.11318	0.17427	0.00518	0.08256	0.00466	0.01068
AP	106	Transmission Plant in Service	TRANPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	107	Distribution Plant in Service	DISTPLT	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	108	General Plant in Service	GENLPLT	1.00000	0.59138	0.11879	0.15581	0.00687	0.10932	0.00612	0.01171
AP	109	Total Electric Plant In Service	TOTPLT	1.00000	0.50553	0.12029	0.20526	0.00630	0.13431	0.00842	0.01989
AP	110										
AP	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	112	Total Transmission and Distribution Plant	TDPLT	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	113	Total Distribution and General Plant	DGPLT	1.00000	0.50293	0.12047	0.20603	0.00633	0.13561	0.00851	0.02012
AP	114	Rate Base	RATEBASE	1.00000	0.51894	0.12142	0.19565	0.00652	0.13315	0.00813	0.01618
AP	115										
AP	116	Account 360	PLT_360	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	117	Account 361	PLT_361	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	118	Account 362	PLT_362	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	119	Account 364	PLT_364	1.00000	0.53035	0.12614	0.19348	0.00741	0.12130	0.00771	0.01361
AP	120	Account 365	PLT_365	1.00000	0.53035	0.12614	0.19348	0.00741	0.12130	0.00771	0.01361
AP	121	Account 366	PLT_366	1.00000	0.50041	0.12152	0.18917	0.00736	0.15896	0.01010	0.01248
AP	122	Account 367	PLT_367	1.00000	0.50041	0.12152	0.18917	0.00736	0.15896	0.01010	0.01248
AP	123	Account 368	PLT_368	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	124	Account 369	PLT_369	1.00000	0.55920	0.08053	0.35304	0.00105	0.00619	0.00000	0.00000
AP	125	Account 370	PLT_370	1.00000	0.72985	0.10511	0.13747	0.00394	0.02330	0.00034	0.00000
AP	126	Account 371	PLT_371	1.00000	0.76925	0.11078	0.08977	0.00000	0.00000	0.00000	0.03021
AP	127	Account 373	PLT_373	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	128	Distribution Overhead Plant in Service	OHDIST	1.00000	0.53035	0.12614	0.19348	0.00741	0.12130	0.00771	0.01361
AP	129	Distribution Underground Plant in Service	UGDIST	1.00000	0.50041	0.12152	0.18917	0.00736	0.15896	0.01010	0.01248
AP	130	Accounts 360 & 361	PLT_3601	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	131	Accounts 371 & 373	PLT_3713	1.00000	0.12273	0.01767	0.01432	0.00000	0.00000	0.00000	0.84527
AP	132										
AP	133	Residential	DPLTRES	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	134	Residential Heating	DPLTRH	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	135	General Service	DPLTGS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	136	Primary Distribution	DPLTPRID	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	137	High Tension	DPLTHT	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	138	Electric Propulsion	DPLTEP	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	139	Lighting	DPLTLCUST	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	140										
AP	141										
AP	142										
AP	143										
AP	144										
AP	145										
AP	146										

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	RESIDENTIAL (d)	RESIDENTIAL HEATING (e)	GENERAL SERVICE (f)	PRIMARY DISTRIBUTION (g)	HIGH TENSION (h)	ELECTRIC PROPULSION (i)	LIGHTING (j)
AP	147										
AP	148										
AP	149										
AP	150										
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	153										
AP	154	**Production Expense Related**									
AP	155	Account 555	OX_555	1.00000	0.63953	0.16807	0.14162	0.00132	0.04838	0.00000	0.00108
AP	156	O&M Expense Production Other	OX_PROD	1.00000	0.63953	0.16807	0.14162	0.00132	0.04838	0.00000	0.00108
AP	157	Salaries and Wages Production Operation	SALWAGPO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	158			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	159										
AP	160	**Transmission Expense Related**									
AP	161	Transmission Operation Expense	OX_TRAN	1.00000	0.46569	0.12094	0.20483	0.00612	0.19248	0.00945	0.00049
AP	162	Transmission Maintenance Expense	MX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	163	Transmission Salaries & Wages Accounts 511	SALWAGTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	164	Transmission Salaries & Wages Accounts 569	SALWAGTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	165										
AP	166										
AP	167	**Distribution Expense Related**									
AP	168	Account 580	OX_580	1.00000	0.60529	0.11732	0.16547	0.00470	0.08891	0.00545	0.01285
AP	169	Account 581	OX_581	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	170	Account 582	OX_582	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	171	Account 583	OX_583	1.00000	0.53035	0.12614	0.19348	0.00741	0.12130	0.00771	0.01361
AP	172	Account 584	OX_584	1.00000	0.50041	0.12152	0.18917	0.00736	0.15896	0.01010	0.01248
AP	173	Account 585	OX_585	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	174	Account 586	OX_586	1.00000	0.72985	0.10511	0.13747	0.00394	0.02330	0.00034	0.00000
AP	175	Account 587	OX_587	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	176	Account 588	OX_588	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	177	Account 589	OX_589	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	178	Account 591	MX_591	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	179	Account 592	MX_592	1.00000	0.37817	0.11396	0.20146	0.00886	0.27393	0.01741	0.00622
AP	180	Account 593	MX_593	1.00000	0.53035	0.12614	0.19348	0.00741	0.12130	0.00771	0.01361
AP	181	Account 594	MX_594	1.00000	0.50041	0.12152	0.18917	0.00736	0.15896	0.01010	0.01248
AP	182	Account 595	MX_595	1.00000	0.54039	0.16284	0.28789	0.00000	0.00000	0.00000	0.00889
AP	183	Account 596	MX_596	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	184	Account 597	MX_597	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	185	Account 598	MX_598	1.00000	0.49984	0.12053	0.20779	0.00631	0.13653	0.00859	0.02042
AP	186	O&M Accounts 581-589	OX_DIST	1.00000	0.55196	0.11832	0.18542	0.00575	0.11643	0.00721	0.01492
AP	187	O&M Accounts 591-598	MX_DIST	1.00000	0.49826	0.12244	0.19411	0.00736	0.14669	0.00932	0.02182
AP	188										
AP	189										
AP	190										
AP	191										
AP	192										
AP	193										
AP	194										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AP	195										
AP	196										
AP	197										
AP	198										
AP	199										
AP	200										
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**									
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**									
AP	203										
AP	204	**Customer Distribution Expense Related**									
AP	205	Account 902	OX_902	1.00000	0.72985	0.10511	0.13747	0.00394	0.02330	0.00034	0.00000
AP	206	Account 903	OX_903	1.00000	0.74357	0.11175	0.08393	0.00749	0.04681	0.00020	0.00624
AP	207	Account 904	OX_904	1.00000	0.72983	0.16544	0.08162	0.00104	0.02194	0.00000	0.00012
AP	208	O&M Accounts 902-905	OX_CA	1.00000	0.74228	0.12867	0.08403	0.00492	0.03558	0.00013	0.00438
AP	209										
AP	210	Account908	OX_908	1.00000	0.78236	0.11784	0.03457	0.00171	0.06012	0.00253	0.00087
AP	211	Account909	OX_909	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	212	Account910	OX_910	1.00000	0.78581	0.11317	0.09170	0.00027	0.00161	0.00002	0.00742
AP	213	O&M Accounts 908-910	OX_CS	1.00000	0.78265	0.11744	0.03947	0.00158	0.05510	0.00231	0.00143
AP	214	Accounts 901-910	X_CACS	1.00000	0.74605	0.12762	0.07987	0.00461	0.03741	0.00033	0.00410
AP	215										
AP	216	Total O&M less Purchased Power	OMXPP	1.00000	0.56009	0.12188	0.16774	0.00630	0.12615	0.00684	0.01100
AP	217	Total O&M less PP less Payroll less Pension	OMXPPPP	1.00000	0.55091	0.12278	0.17124	0.00613	0.13109	0.00705	0.01079
AP	218										
AP	219	**Salaries and Wages Expense Related**									
AP	220	Salaries & Wages Accounts 581-589	SALWAGDO	1.00000	0.60529	0.11732	0.16547	0.00470	0.08891	0.00545	0.01285
AP	221	Salaries & Wages Accounts 591-598	SALWAGDM	1.00000	0.50011	0.12297	0.19448	0.00746	0.15084	0.00958	0.01456
AP	222	Salaries & Wages Accounts 902-905	SALWAGCA	1.00000	0.74489	0.11179	0.08417	0.00727	0.04540	0.00020	0.00628
AP	223	Salaries & Wages Accounts 908-910	SALWAGCS	1.00000	0.78238	0.11781	0.03488	0.00170	0.05981	0.00251	0.00091
AP	224	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	1.00000	0.59068	0.11879	0.15624	0.00689	0.10952	0.00614	0.01175
AP	225	Total Salaries and Wages Expense	SALWAGES	1.00000	0.59138	0.11879	0.15581	0.00687	0.10932	0.00612	0.01171
AP	226										
AP	227	Base Taxable Income	EBT	1.00000	0.50219	0.07397	0.24651	0.00799	0.14411	0.00277	0.02246
AP	228										
AP	229										
AP	230										
AP	231										
AP	232										
AP	233										
AP	234										
AP	235										
AP	236										
AP	237										
AP	238										
AP	239										
AP	240										
AP	241										
AP	242										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AP	243										
AP	244										
AP	245										
AP	246										
AP	247										
AP	248										
AP	249										
AP	250										
AP	251	**REVENUES AND BILLING DETERMINANTS**									
AP	252										
AP	253	Base Rate Sales Revenue	SALESREV	1.00000	0.55617	0.11141	0.18362	0.00668	0.11984	0.00588	0.01639
AP	254										
AP	255	Residential	SREVRES	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	256	Residential Heating	SREVRH	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	257	General Service	SREVGS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	258	Primary Distribution	SREVPRID	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	259	High Tension	SREVHT	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	260	Electric Propulsion	SREVEP	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	261	Lighting	SREVLCUST	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	262										
AP	263										
AP	264										
AP	265										
AP	266	Claimed Rate Sales Revenue	CLAIMREV	1.00000	0.57272	0.13462	0.16823	0.00489	0.10455	0.00516	0.00981
AP	267										
AP	268	Capital Stock	CAPSTOCK	1.00000	0.52130	0.12365	0.19657	0.00597	0.12733	0.00765	0.01753
AP	269										
AP	270										
AP	271										
AP	272	**PRESENT REVENUES/EXPENSES FROM S**									
AP	273										
AP	274	Total Sales of Electricity Revenues		1.00000	0.55704	0.11154	0.18351	0.00667	0.11896	0.00585	0.01643
AP	275	Sales of Electricity Revenues - Distribution		1.00000	0.55617	0.11141	0.18362	0.00668	0.11984	0.00588	0.01639
AP	276	Sales of Electricity Revenues - Nuclear Decom		1.00000	0.28102	0.07270	0.21557	0.01083	0.39773	0.01671	0.00544
AP	277										
AP	278										
AP	279										
AP	280	Sales of Electricity Revenues - Transmission		1.00000	0.46569	0.12094	0.20483	0.00612	0.19248	0.00945	0.00049
AP	281										
AP	282										
AP	283										
AP	284										
AP	285										
AP	286										
AP	287										
AP	288										
AP	289										
AP	290										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
AP	291										
AP	292										
AP	293										
AP	294										
AP	295										
AP	296										
AP	297										
AP	298										
AP	299										
AP	300										
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**									
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
ADA	3										
ADA	4	**Net Write-Offs**									
ADA	5	Residential	SREVRES	67,155,611	67,155,611	0	0	0	0	0	0
ADA	6	Residential Heating	SREVRH	15,223,148	0	15,223,148	0	0	0	0	0
ADA	7	General Service	SREVGS	7,510,106	0	0	7,510,106	0	0	0	0
ADA	8	Primary Distribution	SREVPRID	95,948	0	0	0	95,948	0	0	0
ADA	9	High Tension	SREVHT	2,018,968	0	0	0	0	2,018,968	0	0
ADA	10	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0
ADA	11	Lighting	SREVLCUST	11,428	0	0	0	0	0	0	11,428
ADA	12										
ADA	13										
ADA	14	Total Write-Offs	EXP_904	92,015,208	67,155,611	15,223,148	7,510,106	95,948	2,018,968	0	11,428
ADA	15										
ADA	16	Total Write-Offs	EXP_904	1.00000	0.72983	0.16544	0.08162	0.00104	0.02194	0.00000	0.00012
ADA	17										
ADA	18	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0
ADA	19										
ADA	20										
ADA	21										
ADA	22	**Customer Advances for Construction**									
ADA	23	Residential	DPLTRES	2,030,823	2,030,823	0	0	0	0	0	0
ADA	24	Residential Heating	DPLTRH	487,605	0	487,605	0	0	0	0	0
ADA	25	General Service	DPLTGS	753,038	0	0	753,038	0	0	0	0
ADA	26	Primary Distribution	DPLTPRID	29,051	0	0	0	29,051	0	0	0
ADA	27	High Tension	DPLTHT	546,256	0	0	0	0	546,256	0	0
ADA	28	Electric Propulsion	DPLTEP	34,722	0	0	0	0	0	34,722	0
ADA	29	Lighting	DPLTLCUST	51,435	0	0	0	0	0	0	51,435
ADA	30										
ADA	31										
ADA	32	Customer Advances for Construction	CUSTADV	3,932,929	2,030,823	487,605	753,038	29,051	546,256	34,722	51,435
ADA	33										
ADA	34	Customer Advances for Construction	CUSTADV	1.00000	0.51636	0.12398	0.19147	0.00739	0.13889	0.00883	0.01308
ADA	35										
ADA	36										
ADA	37	**Purchase of Receivables**									
ADA	38	Residential	SREVRES	337,427	337,427	0	0	0	0	0	0

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		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
ADA	39	Residential Heating	SREVRH	87,289	0	87,289	0	0	0	0	0
ADA	40	General Service	SREVGS	336,728	0	0	336,728	0	0	0	0
ADA	41	Primary Distribution	SREVPRID	7,805	0	0	0	7,805	0	0	0
ADA	42	High Tension	SREVHT	286,508	0	0	0	0	286,508	0	0
ADA	43	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0
ADA	44	Lighting	SREVLCUST	6,987	0	0	0	0	0	0	6,987
ADA	45										
ADA	46										
ADA	47	Total POR	POR	1,062,743	337,427	87,289	336,728	7,805	286,508	0	6,987
ADA	48										
ADA	49	Total POR	POR	1.00000	0.31751	0.08214	0.31685	0.00734	0.26959	0.00000	0.00657
ADA	50										
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**									
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**									
ADA	3										
ADA	4	**AVAILABLE**									
ADA	5	Residential	SREVRES	0	0	0	0	0	0	0	0
ADA	6	Residential Heating	SREVRH	0	0	0	0	0	0	0	0
ADA	7	General Service	SREVGS	0	0	0	0	0	0	0	0
ADA	8	Primary Distribution	SREVPRID	0	0	0	0	0	0	0	0
ADA	9	High Tension	SREVHT	0	0	0	0	0	0	0	0
ADA	10	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0
ADA	11	Lighting	SREVLCUST	0	0	0	0	0	0	0	0
ADA	12										
ADA	13										
ADA	14										
ADA	15	Total Available	SREVAVAIL	0	0	0	0	0	0	0	0
ADA	16										
ADA	17	Total Available	SREVAVAIL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ADA	18										
ADA	19										
ADA	20										
ADA	21										
ADA	22										
ADA	23										
ADA	24										
ADA	25										
ADA	26										
ADA	27										
ADA	28										
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ADA	31										
ADA	32										
ADA	33										
ADA	34										
ADA	35										
ADA	36										

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
ADA	37										
ADA	38										
ADA	39										
ADA	40										
ADA	41										
ADA	42										
ADA	43										
ADA	44										
ADA	45										
ADA	46										
ADA	47										
ADA	48										
ADA	49										
ADA	50										
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**									
RRW	2										
RRW	3	PRESENT RATES									
RRW	4	--									
RRW	5	RATE BASE		4,820,415	2,499,673	584,746	944,200	31,518	642,538	39,330	78,409
RRW	6	NET OPER INC (PRESENT RATES)		277,780	141,126	26,306	62,554	2,035	38,737	1,436	5,586
RRW	7	RATE OF RETURN (PRES RATES)		5.76%	5.65%	4.50%	6.63%	6.46%	6.03%	3.65%	7.12%
RRW	8	RELATIVE RATE OF RETURN		1.00	0.98	0.78	1.15	1.12	1.05	0.63	1.24
RRW	9	SALES REVENUE (PRE RATES)		1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
RRW	10	REVENUE PRES RATES $/KWH		$0.0327	$0.0647	$0.0501	$0.0279	$0.0202	$0.0099	$0.0115	$0.0986
RRW	11	REVENUE REQUIRED - $/MO/CUST		$61.66	$43.64	$60.70	$123.46	$1,514.47	$4,595.83	$15,497.94	$136.14
RRW	12	SALES REV REQUIRED $/KW		$19.41	$0.00	$0.00	$8.40	$7.84	$4.37	$4.13	$0.00
RRW	13										
RRW	14	CLAIMED RATE OF RETURN									
RRW	15	--									
RRW	16	CLAIMED RATE OF RETURN		7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
RRW	17	RETURN REQ FOR CLAIMED ROR		375,309	194,620	45,527	73,514	2,454	50,027	3,062	6,105
RRW	18	SALES REVENUE REQ CLAIMED ROR - Distribution		1,371,557	761,694	165,404	241,366	8,809	163,769	9,658	20,858
RRW	19	REVENUE DEFICIENCY SALES REV		146,983	80,619	28,969	16,515	631	17,015	2,452	782
RRW	20	PERCENT INCREASE REQUIRED		12.00%	11.84%	21.23%	7.34%	7.72%	11.59%	34.02%	3.90%
RRW	21	ANNUAL BOOKED KWH SALES		37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
RRW	22	SALES REV REQUIRED $/KWH		$0.0366	$0.0724	$0.0608	$0.0299	$0.0217	$0.0110	$0.0154	$0.1025
RRW	23	REVENUE DEFICIENCY $/KWH		$0.0039	$0.0077	$0.0106	$0.0020	$0.0016	$0.0011	$0.0039	$0.0038
RRW	24	SALES REVENUE REQ CLAIMED ROR - Energy		651,236	416,488	109,453	92,225	858	31,506	0	705
RRW	25	SALES REVENUE REQ CLAIMED ROR - Transmission		183,679	85,517	22,177	37,613	1,126	35,420	1,738	90
RRW	26										
RRW	27										
RRW	28										
RRW	29										
RRW	30										
RRW	31										
RRW	32										
RRW	33										
RRW	34										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	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)
RRW	35										
RRW	36										
RRW	37										
RRW	38										
RRW	39										
RRW	40										
RRW	41										
RRW	42										
RRW	43										
RRW	44										
RRW	45										
RRW	46										
RRW	47										
RRW	48										
RRW	49										
RRW	50										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
S	1	**SUMMARY AT PRESENT RATES**										
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**										
S	3	OPERATING REVENUE										
S	4	Sales of Electricity - Base	SCH RBC, LN 54	1,224,574	701,345	8,997	514,232	0	1,809	699,536	486,428	159,403
S	5	Decommissioning Revenues	SCH RBC, LN 55	(3,860)	0	(3,860)	0	0	0	0	0	0
S	6	Other Operating Revenue	SCH RBC, LN 65	37,547	25,014	64	12,469	0	13	25,002	15,954	7,648
S	7	TOTAL OPERATING REVENUE		1,258,261	726,359	5,201	526,701	0	1,822	724,538	502,382	167,051
S	8											
S	9	OPERATING EXPENSES										
S	10	Operation and Maintenance Expense	SCH E, LN 87	619,817	320,797	4,498	294,521	0	1,244	319,553	224,635	82,295
S	11	Depreciation and Amortization Expense	SCH D, LN 28	235,063	133,358	0	101,706	0	0	133,358	90,384	27,216
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 11	20,557	13,632	105	6,820	0	29	13,603	11,127	1,946
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 35	70,638	40,571	520	29,547	0	105	40,467	28,189	9,184
S	14	Income Taxes	SCH TI, LN 47	34,406	23,929	17	10,460	0	94	23,835	16,165	5,629
S	15	TOTAL OPERATING EXPENSES		980,481	532,287	5,140	443,054	0	1,473	530,815	370,499	126,270
S	16	**OPERATING INCOME (RETURN)**		277,780	194,072	61	83,646	0	349	193,723	131,883	40,781
S	17											
S	18	**DEVELOPMENT OF RATE BASE**										
S	19	Electric Plant in Service	SCH RBP, LN 66	7,193,628	5,067,307	0	2,126,321	0	0	5,067,307	3,467,585	953,863
S	20	Less: Accumulated Depreciation	SCH RBD, LN 25	2,041,533	1,386,133	0	655,400	0	0	1,386,133	975,625	207,423
S	21	Plus: Rate Base Additions	SCH RBO, LN 30	465,301	244,588	1,059	219,654	0	6,048	238,539	170,892	58,227
S	22	Less: Rate Base Deductions	SCH RBO, LN 27	796,981	573,252	0	223,729	0	0	573,252	389,597	97,319
S	23	**TOTAL DISTRIBUTION RATE BASE**	SCH RBO, LN 34	4,820,415	3,352,510	1,059	1,466,847	0	6,048	3,346,461	2,273,254	707,349
S	24											
S	25	**DISTRIBUTION RATE OF RETURN (PRESENT)**		5.76%	5.79%	5.79%	5.70%	61.07%	5.77%	5.79%	5.80%	5.77%
S	26	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	27											
S	28	**DEVELOPMENT OF PURCHASED POWER RETURN**										
S	29	Purchased Electric Revenues	SCH RBC, LN 57	653,769	0	653,769	0	0	0	0	0	0
S	30	Purchased Power O&M Expense	SCH E, LN 41	610,818	0	610,818	0	0	0	0	0	0
S	31	Purchased Power GRT Expense	SCH TO, LN 21	38,572	0	38,572	0	0	0	0	0	0
S	32	Purchased Power Income Taxes		1,155	0	1,155	0	0	0	0	0	0
S	33	Purchased Power Operating Income		3,224	0	3,224	0	0	0	0	0	0
S	34	Rate Base - Purchased Pwr Cash Working Capital	SCH RBC, LN 33	19,631	0	19,631	0	0	0	0	0	0
S	35	**PURCHASED POWER RATE OF RETURN (PRESENT)**		16.42%	0.00%	16.42%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	36											
S	37	**DEVELOPMENT OF TRANSMISSON RETURN**										
S	38	Transmission Revenues	SCH RBC, LN 56	185,615	185,615	0	0	0	185,615	0	0	0
S	39	Transmission O&M Expense	SCH E, LN 42	172,218	172,218	0	0	0	172,218	0	0	0
S	40	Transmission GRT Expense	SCH TO, LN 28	10,951	10,951	0	0	0	10,951	0	0	0
S	41	Transmission Income Taxes		672	672	0	0	0	672	0	0	0
S	42	Transmission Operating Income		1,773	1,773	0	0	0	1,773	0	0	0
S	43	Rate Base - Transmission Cash Working Capital	SCH RBO, LN 33	6,141	6,141	0	0	0	6,141	0	0	0
S	44	**TRANSMISSION RATE OF RETURN (PRESENT)**		28.87%	28.87%	0.00%	0.00%	0.00%	28.87%	0.00%	0.00%	0.00%
S	45											
S	46	**TOTAL OPERATING INCOME (RETURN)**		282,776	195,845	3,285	83,646	0	2,122	193,723	131,883	40,781
S	47	**TOTAL RATE BASE**		4,846,186	3,358,651	20,689	1,466,847	0	12,189	3,346,461	2,273,254	707,349
S	48	**COMPOSITE RATE OF RETURN @ CURRENT RATES**		5.84%	5.83%	15.88%	5.70%	61.07%	17.41%	5.79%	5.80%	5.77%
S	49											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
S	1	**SUMMARY AT PRESENT RATES**											
S	2	**DEVELOPMENT OF DISTRIBUTION RETURN**											
S	3	OPERATING REVENUE											
S	4	Sales of Electricity - Base	SCH RBC, LN 54	0	53,705	8,997	0	174,862	31,326	83,991	178,249	19,241	26,563
S	5	Decommissioning Revenues	SCH RBC, LN 55	0	0	(3,860)	0	0	0	0	0	0	0
S	6	Other Operating Revenue	SCH RBC, LN 65	0	1,399	64	0	8,144	897	1,286	1,633	182	327
S	7	TOTAL OPERATING REVENUE		0	55,104	5,201	0	183,006	32,223	85,277	179,882	19,423	26,890
S	8												
S	9	OPERATING EXPENSES											
S	10	Operation and Maintenance Expense	SCH E, LN 87	0	12,623	4,498	0	89,666	6,897	23,381	137,969	16,538	20,070
S	11	Depreciation and Amortization Expense	SCH D, LN 28	0	15,758	0	0	30,401	9,583	42,163	14,592	793	4,174
S	12	Taxes Other Than Income Taxes-General	SCH TO, LN 11	0	530	105	0	2,146	340	553	3,092	170	519
S	13	Taxes Other Than Income Taxes-Distribution GRT	SCH TO, LN 35	0	3,094	520	0	10,039	1,807	4,825	10,237	1,104	1,534
S	14	Income Taxes	SCH TI, LN 47	0	2,041	17	0	5,920	966	1,069	2,639	155	(288)
S	15	TOTAL OPERATING EXPENSES		0	34,046	5,140	0	138,172	19,593	71,992	168,530	18,759	26,009
S	16	**OPERATING INCOME (RETURN)**		0	21,059	61	0	44,834	12,631	13,286	11,352	663	881
S	17												
S	18	**DEVELOPMENT OF RATE BASE**											
S	19	Electric Plant in Service	SCH RBP, LN 66	0	645,859	0	0	1,074,603	441,035	441,483	67,782	3,684	97,734
S	20	Less: Accumulated Depreciation	SCH RBD, LN 25	0	203,085	0	0	233,149	173,169	178,982	21,580	1,173	47,346
S	21	Plus: Rate Base Additions	SCH RBO, LN 30	0	9,420	1,059	0	62,195	5,375	15,920	111,411	7,009	17,744
S	22	Less: Rate Base Deductions	SCH RBO, LN 27	0	86,336	0	0	110,427	59,317	44,240	(43,839)	(2,383)	55,968
S	23	**TOTAL DISTRIBUTION RATE BASE**	SCH RBO, LN 34	0	365,858	1,059	0	793,222	213,924	234,182	201,452	11,903	12,164
S	24												
S	25	**DISTRIBUTION RATE OF RETURN (PRESENT)**		60.73%	5.76%	5.79%	60.83%	5.65%	5.90%	5.67%	5.64%	5.57%	7.24%
S	26	**DISTRIBUTION INDEX RATE OF RETURN (PRESENT)**		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
S	27												
S	28	**DEVELOPMENT OF PURCHASED POWER RETURN**											
S	29	Purchased Electric Revenues	SCH RBC, LN 57	0	0	653,769	0	0	0	0	0	0	0
S	30	Purchased Power O&M Expense	SCH E, LN 41	0	0	610,818	0	0	0	0	0	0	0
S	31	Purchased Power GRT Expense	SCH TO, LN 21	0	0	38,572	0	0	0	0	0	0	0
S	32	Purchased Power Income Taxes		0	0	1,155	0	0	0	0	0	0	0
S	33	Purchased Power Operating Income		0	0	3,224	0	0	0	0	0	0	0
S	34	Rate Base - Purchased Pwr Cash Working Capital	SCH RBC, LN 33	0	0	19,631	0	0	0	0	0	0	0
S	35	**PURCHASED POWER RATE OF RETURN (PRESENT)**		0.00%	0.00%	16.42%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	36												
S	37	**DEVELOPMENT OF TRANSMISSON RETURN**											
S	38	Transmission Revenues	SCH RBC, LN 56	0	0	0	0	0	0	0	0	0	0
S	39	Transmission O&M Expense	SCH E, LN 42	0	0	0	0	0	0	0	0	0	0
S	40	Transmission GRT Expense	SCH TO, LN 28	0	0	0	0	0	0	0	0	0	0
S	41	Transmission Income Taxes		0	0	0	0	0	0	0	0	0	0
S	42	Transmission Operating Income		0	0	0	0	0	0	0	0	0	0
S	43	Rate Base - Transmission Cash Working Capital	SCH RBO, LN 33	0	0	0	0	0	0	0	0	0	0
S	44	**TRANSMISSION RATE OF RETURN (PRESENT)**		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	45												
S	46	**TOTAL OPERATING INCOME (RETURN)**		0	21,059	3,285	0	44,834	12,631	13,286	11,352	663	881
S	47	**TOTAL RATE BASE**		0	365,858	20,689	0	793,222	213,924	234,182	201,452	11,903	12,164
S	48	**COMPOSITE RATE OF RETURN @ CURRENT RATES**		60.73%	5.76%	15.88%	60.83%	5.65%	5.90%	5.67%	5.64%	5.57%	7.24%
S	49												

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
S	50											
S	51	EQUALIZED RETURN AT PROPOSED ROR OF 7.79%										
S	52	DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)										
S	53	RATE BASE	SCH S, LN 23	4,820,415	3,352,510	1,059	1,466,847	0	6,048	3,346,461	2,273,254	707,349
S	54	RETURN (RATE BASE * 7.79% ROR)		375,309	261,020	82	114,206	0	471	260,549	176,991	55,073
S	55	PLUS:										
S	56	OPERATING EXPENSES										
S	57	Operation and Maintenance Expense	CALCULATED	621,586	322,026	4,467	295,093	0	1,222	320,804	225,479	82,562
S	58	Depreciation and Amortization Expense	SCH S, LN 11	235,063	133,358	0	101,706	0	0	133,358	90,384	27,216
S	59	Taxes Other Than Income Taxes-General	SCH S, LN 12	20,557	13,632	105	6,820	0	29	13,603	11,127	1,946
S	60	Taxes Other Than Income Taxes-Distribution GRT	CALCULATED	79,310	46,525	521	32,265	0	114	46,410	32,201	10,455
S	61	State and Federal Income Taxes	CALCULATED	74,034	51,131	26	22,877	0	144	50,987	34,493	11,436
S	62	TOTAL OPERATING EXPENSES		1,030,551	566,672	5,118	458,761	0	1,510	565,162	393,683	133,616
S	63											
S	64	EQUALS TOTAL COST OF SERVICE		1,405,860	827,692	5,200	572,967	0	1,981	825,711	570,674	188,689
S	65	LESS:										
S	66	Decommissioning Revenues	SCH S, LN 5	(3,860)	0	(3,860)	0	0	0	0	0	0
S	67	Other Operating Revenue	CALCULATED	38,162	25,442	53	12,668	0	5	25,437	16,248	7,741
S	68	EQUALS:										
S	69	DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.79%		1,371,557	802,251	9,007	560,299	0	1,976	800,274	554,427	180,948
S	70	Distribution Cost Increase without Forfeited Discount		146,985	100,906	11	46,067	0	168	100,738	67,999	21,545
S	71	TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE		147,599	101,333	(0)	46,266	(0)	160	101,173	68,292	21,638
S	72	REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISC		12.00%	14.39%	0.13%	8.96%	3.47%	9.29%	14.40%	13.98%	13.52%
S	73			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	74	DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)										
S	75	RATE BASE (CWC)	SCH S, LN 34	19,631	0	19,631	0	0	0	0	0	0
S	76	RETURN (RATE BASE * 7.79% ROR)		1,528	0	1,528	0	0	0	0	0	0
S	77	PLUS:										
S	78	OPERATING EXPENSES										
S	79	Purchased Power O&M Expense	SCH S, LN 30	610,818	0	610,818	0	0	0	0	0	0
S	80	Purchased Power Income Taxes	CALCULATED	466	0	466	0	0	0	0	0	0
S	81	Purchased Power GRT Expense	CALCULATED	38,423	0	38,423	0	0	0	0	0	0
S	82	EQUALS TOTAL PURCHASED POWER COST OF SERVICE		651,236	0	651,236	0	0	0	0	0	0
S	83	TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE		(2,533)	0	(2,533)	0	0	0	0	0	0
S	84	REVENUE INCREASE TO DISTRIBUTION REVENUES (%)		-0.39%	0.00%	-0.39%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	85			7.79%	0.00%	7.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)										
S	87	RATE BASE (CWC)	SCH S, LN 43	6,141	6,141	0	0	0	6,141	0	0	0
S	88	RETURN (RATE BASE * 7.79% ROR)		478	478	0	0	0	478	0	0	0
S	89	PLUS:										
S	90	OPERATING EXPENSES										
S	91	Transmission O&M Expense	SCH S, LN 39	172,218	172,218	0	0	0	172,218	0	0	0
S	92	Transmission Income Taxes	CALCULATED	146	146	0	0	0	146	0	0	0
S	93	Transmission GRT Expense	CALCULATED	10,837	10,837	0	0	0	10,837	0	0	0
S	94	EQUALS TOTAL TRANSMISSION COST OF SERVICE		183,679	183,679	0	0	0	183,679	0	0	0
S	95	TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE		(1,935)	(1,935)	0	0	0	(1,935)	0	0	0
S	96	REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)		-1.04%	-1.04%	0.00%	0.00%	0.00%	-1.04%	0.00%	0.00%	0.00%
S	97			7.79%	7.79%	0.00%	0.00%	0.00%	7.79%	0.00%	0.00%	0.00%
S	98	TOTAL INCREASE (DECREASE) REQUIRED		143,130	99,398	(2,534)	46,266	(0)	(1,776)	101,173	68,292	21,638

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
S	50												
S	51	**EQUALIZED RETURN AT PROPOSED ROR OF 7.79%**											
S	52	**DEVELOPMENT OF DISTRIBUTION RETURN (EQUALIZED RATE)**											
S	53	**RATE BASE**	SCH S, LN 23	0	365,858	1,059	0	793,222	213,924	234,182	201,452	11,903	12,164
S	54	**RETURN (RATE BASE * 7.79% ROR)**		0	28,485	82	0	61,759	16,656	18,233	15,685	927	947
S	55	**PLUS:**											
S	56	**OPERATING EXPENSES**											
S	57	Operation and Maintenance Expense	CALCULATED	0	12,762	4,467	0	89,983	6,972	23,473	138,050	16,543	20,071
S	58	Depreciation and Amortization Expense	SCH S, LN 11	0	15,758	0	0	30,401	9,583	42,163	14,592	793	4,174
S	59	Taxes Other Than Income Taxes-General	SCH S, LN 12	0	530	105	0	2,146	340	553	3,092	170	519
S	60	Taxes Other Than Income Taxes-Distribution GRT	CALCULATED	0	3,755	521	0	11,545	2,165	5,265	10,622	1,127	1,540
S	61	State and Federal Income Taxes	CALCULATED	0	5,058	26	0	12,797	2,601	3,080	4,399	262	(261)
S	62	**TOTAL OPERATING EXPENSES**		0	37,863	5,118	0	146,871	21,661	74,534	170,756	18,895	26,043
S	63												
S	64	**EQUALS TOTAL COST OF SERVICE**		0	66,348	5,200	0	208,630	38,317	92,767	186,441	19,822	26,990
S	65	**LESS:**											
S	66	Decommissioning Revenues	SCH S, LN 5	0	0	(3,860)	0	0	0	0	0	0	0
S	67	Other Operating Revenue	CALCULATED	0	1,448	53	0	8,254	924	1,318	1,661	184	327
S	68	**EQUALS:**											
S	69	**DISTRIBUTION BASE RATE SALES @ EQUALIZED ROR 7.79%**		0	64,900	9,007	0	200,376	37,394	91,449	184,780	19,638	26,663
S	70	Distribution Cost Increase without Forfeited Discount		0	11,195	11	0	25,514	6,068	7,458	6,531	397	100
S	71	**TOTAL COST OF SERVICE DISTRIBUTION INCREASE/DECREASE**		(0)	11,244	(0)	(0)	25,624	6,094	7,490	6,559	399	100
S	72	**REVENUE INCREASE TO DISTRIBUTION REVENUES W/O FORFEITED DISC(**		3.69%	20.85%	0.13%	3.65%	14.59%	19.37%	8.88%	3.66%	2.07%	0.38%
S	73			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	74	**DEVELOPMENT OF PURCH. POWER RETURN (EQUALIZED RATE)**											
S	75	**RATE BASE (CWC)**	SCH S, LN 34	0	0	19,631	0	0	0	0	0	0	0
S	76	**RETURN (RATE BASE * 7.79% ROR)**		0	0	1,528	0	0	0	0	0	0	0
S	77	**PLUS:**											
S	78	**OPERATING EXPENSES**											
S	79	Purchased Power O&M Expense	SCH S, LN 30	0	0	610,818	0	0	0	0	0	0	0
S	80	Purchased Power Income Taxes	CALCULATED	0	0	466	0	0	0	0	0	0	0
S	81	Purchased Power GRT Expense	CALCULATED	0	0	38,423	0	0	0	0	0	0	0
S	82	**EQUALS TOTAL PURCHASED POWER COST OF SERVICE**		0	0	651,236	0	0	0	0	0	0	0
S	83	**TOTAL COST OF SERVICE PURCH.POWER INCREASE/DECREASE**		0	0	(2,533)	0	0	0	0	0	0	0
S	84	**REVENUE INCREASE TO DISTRIBUTION REVENUES (%)**		0.00%	0.00%	-0.39%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	85			0.00%	0.00%	7.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	86	**DEVELOPMENT OF TRANSMISSION RETURN (EQUALIZED RATE)**											
S	87	**RATE BASE (CWC)**	SCH S, LN 43	0	0	0	0	0	0	0	0	0	0
S	88	**RETURN (RATE BASE * 7.79% ROR)**		0	0	0	0	0	0	0	0	0	0
S	89	**PLUS:**											
S	90	**OPERATING EXPENSES**											
S	91	Transmission O&M Expense	SCH S, LN 39	0	0	0	0	0	0	0	0	0	0
S	92	Transmission Income Taxes	CALCULATED	0	0	0	0	0	0	0	0	0	0
S	93	Transmission GRT Expense	CALCULATED	0	0	0	0	0	0	0	0	0	0
S	94	**EQUALS TOTAL TRANSMISSION COST OF SERVICE**		0	0	0	0	0	0	0	0	0	0
S	95	**TOTAL COST OF SERVICE TRANSMISSION INCREASE/DECREASE**		0	0	0	0	0	0	0	0	0	0
S	96	**REVENUE INCREASE TO RETAIL DISTRIBUTION REVENUES (%)**		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	97			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	98	**TOTAL INCREASE (DECREASE) REQUIRED**		(0)	11,244	(2,534)	(0)	25,624	6,094	7,490	6,559	399	100

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
S	99											
S	100											
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.79%**										
S	102	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**										
S	103	**RATE BASE**	CALCULATED	4,846,186	3,358,651	20,689	1,466,847	0	12,189	3,346,461	2,273,254	707,349
S	104	**RETURN (RATE BASE * 7.79% ROR)**		377,315	261,498	1,611	114,206	0	949	260,549	176,991	55,073
S	105	**PLUS:**										
S	106	**OPERATING EXPENSES**										
S	107	Operation and Maintenance Expense	CALCULATED	1,404,623	494,244	615,286	295,093	0	173,441	320,804	225,479	82,562
S	108	Depreciation and Amortization Expense	SCH S, LN 58	235,063	133,358	0	101,706	0	0	133,358	90,384	27,216
S	109	Taxes Other Than Income Taxes-General	SCH S, LN 59	20,557	13,632	105	6,820	0	29	13,603	11,127	1,946
S	110	Taxes Other Than Income Taxes-GRT	CALCULATED	128,570	57,362	38,943	32,265	0	10,952	46,410	32,201	10,455
S	111	State and Federal Income Taxes	CALCULATED	74,646	51,277	492	22,877	0	290	50,987	34,493	11,436
S	112	**TOTAL OPERATING EXPENSES**		1,863,460	749,873	654,826	458,761	0	184,712	565,162	393,683	133,616
S	113											
S	114	**EQUALS TOTAL COST OF SERVICE**		2,240,775	1,011,372	656,437	572,967	0	185,661	825,711	570,674	188,689
S	115	**LESS:**										
S	116	Decommissioning Revenues	SCH S, LN 66	(3,860)	0	(3,860)	0	0	0	0	0	0
S	117	Other Operating Revenue	SCH S, LN 67	38,162	25,442	53	12,668	0	5	25,437	16,248	7,741
S	118	**EQUALS:**										
S	119	**OVERALL BASE RATES @ EQUALIZED ROR 7.79%**		2,206,473	985,930	660,243	560,299	0	185,656	800,274	554,427	180,948
S	120	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISC**		142,515	98,970	(2,523)	46,067	(0)	(1,768)	100,738	67,999	21,545
S	121	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**		143,130	99,398	(2,534)	46,266	(0)	(1,776)	101,173	68,292	21,638
S	122			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	123											
S	124											
S	125											
S	126											
S	127											
S	128											
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S	145											
S	146											
S	147											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
S	99												
S	100												
S	101	**EQUALIZED RETURN AT PROPOSED ROR OF 7.79%**											
S	102	**DEVELOPMENT OF OVERALL RETURN (EQUALIZED RATE)**											
S	103	**RATE BASE**	CALCULATED	0	365,858	20,689	0	793,222	213,924	234,182	201,452	11,903	12,164
S	104	**RETURN (RATE BASE * 7.79% ROR)**		0	28,485	1,611	0	61,759	16,656	18,233	15,685	927	947
S	105	**PLUS:**											
S	106	**OPERATING EXPENSES**											
S	107	Operation and Maintenance Expense	CALCULATED	0	12,762	615,286	0	89,983	6,972	23,473	138,050	16,543	20,071
S	108	Depreciation and Amortization Expense	SCH S, LN 58	0	15,758	0	0	30,401	9,583	42,163	14,592	793	4,174
S	109	Taxes Other Than Income Taxes-General	SCH S, LN 59	0	530	105	0	2,146	340	553	3,092	170	519
S	110	Taxes Other Than Income Taxes-GRT	CALCULATED	0	3,755	38,943	0	11,545	2,165	5,265	10,622	1,127	1,540
S	111	State and Federal Income Taxes	CALCULATED	0	5,058	492	0	12,797	2,601	3,080	4,399	262	(261)
S	112	**TOTAL OPERATING EXPENSES**		0	37,863	654,826	0	146,871	21,661	74,534	170,756	18,895	26,043
S	113												
S	114	**EQUALS TOTAL COST OF SERVICE**		0	66,348	656,437	0	208,630	38,317	92,767	186,441	19,822	26,990
S	115	**LESS:**											
S	116	Decommissioning Revenues	SCH S, LN 66	0	0	(3,860)	0	0	0	0	0	0	0
S	117	Other Operating Revenue	SCH S, LN 67	0	1,448	53	0	8,254	924	1,318	1,661	184	327
S	118	**EQUALS:**											
S	119	**OVERALL BASE RATES @ EQUALIZED ROR 7.79%**		0	64,900	660,243	0	200,376	37,394	91,449	184,780	19,638	26,663
S	120	**COST OF SERVICE OVERALL INCREASE/DECREASE W/O FORFEITED DISC**		(0)	11,195	(2,523)	(0)	25,514	6,068	7,458	6,531	397	100
S	121	**TOTAL COST OF SERVICE OVERALL INCREASE/DECREASE**		(0)	11,244	(2,534)	(0)	25,624	6,094	7,490	6,559	399	100
S	122			7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
S	123												
S	124												
S	125												
S	126												
S	127												
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S	146												
S	147												

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
S	148											
S	149											
S	150											
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. Plan	TDPLT	91,924	66,238	0	25,686	0	0	66,238	45,282	12,356
RBP	5	302-	CUSTRES	0	0	0	0	0	0	0	0	0
RBP	6	303-	CUST	0	0	0	0	0	0	0	0	0
RBP	7	303-AMI Plant	CMETERS	83,726	0	0	83,726	0	0	0	0	0
RBP	8	TOTAL INTANGIBLE PLANT		175,650	66,238	0	109,413	0	0	66,238	45,282	12,356
RBP	9											
RBP	10	TRANSMISSION PLANT										
RBP	11	350-359 Accounts	DTRAN	0	0	0	0	0	0	0	0	0
RBP	12	361- Transmission Related Plant	DTRAN	0	0	0	0	0	0	0	0	0
RBP	13	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0
RBP	14											
RBP	15	DISTRIBUTION PLANT										
RBP	16	360-Land & Land Rights	DDISPHT	42,884	42,884	0	0	0	0	42,884	42,884	0
RBP	17	361-Structures & Improvements	DDISPHT	139,261	139,261	0	0	0	0	139,261	139,261	0
RBP	18	362-Station Equipment	DDISPHT	1,163,133	1,163,133	0	0	0	0	1,163,133	1,163,133	0
RBP	19	364-Poles,Towers & Fixtures										
RBP	20	Primary HT	DDISPHT	333,905	333,905	0	0	0	0	333,905	333,905	0
RBP	21	Primary	DDISTPOL	210,305	210,305	0	0	0	0	210,305	0	210,305
RBP	22	Secondary	CDISTSOLC	209,812	0	0	209,812	0	0	0	0	0
RBP	23	Total Account 364		754,022	544,210	0	209,812	0	0	544,210	333,905	210,305
RBP	24	365-Overhead Conductors & Devices										
RBP	25	Primary HT	DDISPHT	594,249	594,249	0	0	0	0	594,249	594,249	0
RBP	26	Primary	DDISTPOL	374,278	374,278	0	0	0	0	374,278	0	374,278
RBP	27	Secondary	CDISTSULC	373,401	0	0	373,401	0	0	0	0	0
RBP	28	Total Account 365		1,341,927	968,526	0	373,401	0	0	968,526	594,249	374,278
RBP	29	366-Underground Conduit										
RBP	30	Primary HT	DDISPHT	269,392	269,392	0	0	0	0	269,392	269,392	0
RBP	31	Primary	DDISTPUL	82,541	82,541	0	0	0	0	82,541	0	82,541
RBP	32	Secondary	CDISTSOLC	112,290	0	0	112,290	0	0	0	0	0
RBP	33	Total Account 366		464,223	351,933	0	112,290	0	0	351,933	269,392	82,541
RBP	34	367-Underground Conductors & Devices										
RBP	35	Primary HT	DDISPHT	796,621	796,621	0	0	0	0	796,621	796,621	0
RBP	36	Primary	DDISTPUL	244,084	244,084	0	0	0	0	244,084	0	244,084
RBP	37	Secondary	CDISTSULC	332,053	0	0	332,053	0	0	0	0	0
RBP	38	Total Account 367		1,372,757	1,040,705	0	332,053	0	0	1,040,705	796,621	244,084
RBP	39	368-Line Transformers	DDISTSUT	634,209	634,209	0	0	0	0	634,209	0	0
RBP	40	369-Services	CSERVICE	433,534	0	0	433,534	0	0	0	0	0
RBP	41	370-Meters	CMETERS	346,878	0	0	346,878	0	0	0	0	0
RBP	42	371-Installation on Customer Premises	CUSTPREM	13,772	0	0	13,772	0	0	0	0	0
RBP	43	373-Street Lighting & Signal Systems	CLIGHT	72,548	0	0	72,548	0	0	0	0	0
RBP	44	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	1,893	1,364	0	529	0	0	1,364	932	254
RBP	45	TOTAL DISTRIBUTION PLANT		6,781,042	4,886,225	0	1,894,817	0	0	4,886,225	3,340,376	911,462
RBP	46											

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
S	148												
S	149												
S	150												
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. Plan	TDPLT	0	8,600	0	0	13,933	5,879	4,704	0	0	1,170
RBP	5	302-	CUSTRES	0	0	0	0	0	0	0	0	0	0
RBP	6	303-	CUST	0	0	0	0	0	0	0	0	0	0
RBP	7	303-AMI Plant	CMETERS	0	0	0	0	0	0	83,726	0	0	0
RBP	8	TOTAL INTANGIBLE PLANT		0	8,600	0	0	13,933	5,879	88,430	0	0	1,170
RBP	9												
RBP	10	TRANSMISSION PLANT											
RBP	11	350-359 Accounts	DTRAN	0	0	0	0	0	0	0	0	0	0
RBP	12	361- Transmission Related Plant	DTRAN	0	0	0	0	0	0	0	0	0	0
RBP	13	TOTAL TRANSMISSION PLANT		0	0	0	0	0	0	0	0	0	0
RBP	14												
RBP	15	DISTRIBUTION PLANT											
RBP	16	360-Land & Land Rights	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	17	361-Structures & Improvements	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	18	362-Station Equipment	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	19	364-Poles,Towers & Fixtures											
RBP	20	Primary HT	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	21	Primary	DDISTPOL	0	0	0	0	0	0	0	0	0	0
RBP	22	Secondary	CDISTSOLC	0	0	0	0	209,812	0	0	0	0	0
RBP	23	Total Account 364		0	0	0	0	209,812	0	0	0	0	0
RBP	24	365-Overhead Conductors & Devices											
RBP	25	Primary HT	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	26	Primary	DDISTPOL	0	0	0	0	0	0	0	0	0	0
RBP	27	Secondary	CDISTSULC	0	0	0	0	373,401	0	0	0	0	0
RBP	28	Total Account 365		0	0	0	0	373,401	0	0	0	0	0
RBP	29	366-Underground Conduit											
RBP	30	Primary HT	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	31	Primary	DDISTPUL	0	0	0	0	0	0	0	0	0	0
RBP	32	Secondary	CDISTSOLC	0	0	0	0	112,290	0	0	0	0	0
RBP	33	Total Account 366		0	0	0	0	112,290	0	0	0	0	0
RBP	34	367-Underground Conductors & Devices											
RBP	35	Primary HT	DDISPHT	0	0	0	0	0	0	0	0	0	0
RBP	36	Primary	DDISTPUL	0	0	0	0	0	0	0	0	0	0
RBP	37	Secondary	CDISTSULC	0	0	0	0	332,053	0	0	0	0	0
RBP	38	Total Account 367		0	0	0	0	332,053	0	0	0	0	0
RBP	39	368-Line Transformers	DDISTSUT	0	634,209	0	0	0	0	0	0	0	0
RBP	40	369-Services	CSERVICE	0	0	0	0	0	433,534	0	0	0	0
RBP	41	370-Meters	CMETERS	0	0	0	0	0	0	346,878	0	0	0
RBP	42	371-Installation on Customer Premises	CUSTPREM	0	0	0	0	0	0	0	0	0	13,772
RBP	43	373-Street Lighting & Signal Systems	CLIGHT	0	0	0	0	0	0	0	0	0	72,548
RBP	44	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	0	177	0	0	287	121	97	0	0	24
RBP	45	TOTAL DISTRIBUTION PLANT		0	634,387	0	0	1,027,842	433,655	346,975	0	0	86,344
RBP	46												

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBP	47											
RBP	48											
RBP	49											
RBP	50											
RBP	51	**ELECTRIC PLANT IN SERVICE CONTINUED**										
RBP	52											
RBP	53	GENERAL PLANT										
RBP	54	389-Land and Land Rights	SALWAGES	943	457	0	486	0	0	457	326	120
RBP	55	390-Structures and Improvements	SALWAGES	44,443	21,542	0	22,901	0	0	21,542	15,367	5,636
RBP	56	391-Office Furniture & Equipment	SALWAGES	14,402	6,981	0	7,421	0	0	6,981	4,980	1,826
RBP	57	393-Store Equipment	SALWAGES	35	17	0	18	0	0	17	12	4
RBP	58	394-Tools, Shop & Garage Equip.	SALWAGES	30,362	14,717	0	15,646	0	0	14,717	10,498	3,850
RBP	59	395-Laboratory Equipment	SALWAGES	372	180	0	192	0	0	180	129	47
RBP	60	397-Communication Equipment	SALWAGES	144,410	69,996	0	74,414	0	0	69,996	49,933	18,312
RBP	61	398-Miscellaneous Equipment / ARO	SALWAGES	485	235	0	250	0	0	235	168	61
RBP	62	399-Other Tangible Property	SALWAGES	1,483	719	0	764	0	0	719	513	188
RBP	63	TOTAL GENERAL PLANT		236,936	114,844	0	122,092	0	0	114,844	81,926	30,045
RBP	64											
RBP	65											
RBP	66	**TOTAL ELECTRIC PLANT IN SERVICE**		7,193,628	5,067,307	0	2,126,321	0	0	5,067,307	3,467,585	953,863
RBP	67											
RBP	68											
RBP	69											
RBP	70											
RBP	71											
RBP	72											
RBP	73											
RBP	74											
RBP	75											
RBP	76											
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RBP	90											
RBP	91											
RBP	92											
RBP	93											
RBP	94											
RBP	95											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBP	47												
RBP	48												
RBP	49												
RBP	50												
RBP	51	**ELECTRIC PLANT IN SERVICE CONTINUED**											
RBP	52												
RBP	53	GENERAL PLANT											
RBP	54	389-Land and Land Rights	SALWAGES	0	11	0	0	131	6	24	270	15	41
RBP	55	390-Structures and Improvements	SALWAGES	0	539	0	0	6,157	282	1,140	12,714	691	1,917
RBP	56	391-Office Furniture & Equipment	SALWAGES	0	175	0	0	1,995	91	369	4,120	224	621
RBP	57	393-Store Equipment	SALWAGES	0	0	0	0	5	0	1	10	1	2
RBP	58	394-Tools, Shop & Garage Equip.	SALWAGES	0	368	0	0	4,207	192	779	8,686	472	1,310
RBP	59	395-Laboratory Equipment	SALWAGES	0	5	0	0	52	2	10	106	6	16
RBP	60	397-Communication Equipment	SALWAGES	0	1,751	0	0	20,008	915	3,705	41,313	2,245	6,229
RBP	61	398-Miscellaneous Equipment / ARO	SALWAGES	0	6	0	0	67	3	12	139	8	21
RBP	62	399-Other Tangible Property	SALWAGES	0	18	0	0	205	9	38	424	23	64
RBP	63	TOTAL GENERAL PLANT		0	2,873	0	0	32,827	1,502	6,078	67,782	3,684	10,219
RBP	64												
RBP	65												
RBP	66	**TOTAL ELECTRIC PLANT IN SERVICE**		0	645,859	0	0	1,074,603	441,035	441,483	67,782	3,684	97,734
RBP	67												
RBP	68												
RBP	69												
RBP	70												
RBP	71												
RBP	72												
RBP	73												
RBP	74												
RBP	75												
RBP	76												
RBP	77												
RBP	78												
RBP	79												
RBP	80												
RBP	81												
RBP	82												
RBP	83												
RBP	84												
RBP	85												
RBP	86												
RBP	87												
RBP	88												
RBP	89												
RBP	90												
RBP	91												
RBP	92												
RBP	93												
RBP	94												
RBP	95												

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBP	96											
RBP	97											
RBP	98											
RBP	99											
RBP	100											
RBD	1	**LESS: ACCUMULATED DEPRECIATION**										
RBD	2											
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATIO	INTPLT	118,520	44,694	0	73,826	0	0	44,694	30,554	8,337
RBD	4											
RBD	5	TRANSMISSION PLANT ACCUMULATED DEPRECIA	TRANPLT	0	0	0	0	0	0	0	0	0
RBD	6											
RBD	7	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION										
RBD	8	360-Land & Land Rights	PLT_360	0	0	0	0	0	0	0	0	0
RBD	9	361-Structures & Improvements	PLT_361	40,671	40,671	0	0	0	0	40,671	40,671	0
RBD	10	362-Station Equipment	PLT_362	465,114	465,114	0	0	0	0	465,114	465,114	0
RBD	11	364-Poles,Towers & Fixtures	PLT_364	157,920	113,978	0	43,942	0	0	113,978	69,932	44,046
RBD	12	365-Overhead Conductors & Devices	PLT_365	281,578	203,227	0	78,351	0	0	203,227	124,692	78,535
RBD	13	366-Underground Conduit	PLT_366	166,178	125,982	0	40,196	0	0	125,982	96,434	29,547
RBD	14	367-Underground Conductors & Devices	PLT_367	208,793	158,289	0	50,504	0	0	158,289	121,164	37,125
RBD	15	368-Line Transformers	PLT_368	196,182	196,182	0	0	0	0	196,182	0	0
RBD	16	369-Services	PLT_369	168,597	0	0	168,597	0	0	0	0	0
RBD	17	370-Meters	PLT_370	117,277	0	0	117,277	0	0	0	0	0
RBD	18	371-Installation on Customer Premises	PLT_371	7,907	0	0	7,907	0	0	0	0	0
RBD	19	373-Street Lighting & Signal Systems	PLT_373	35,370	0	0	35,370	0	0	0	0	0
RBD	20	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	1,990	1,434	0	556	0	0	1,434	980	268
RBD	21	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		1,847,578	1,304,876	0	542,703	0	0	1,304,876	918,988	189,520
RBD	22											
RBD	23	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	75,435	36,564	0	38,871	0	0	36,564	26,083	9,566
RBD	24											
RBD	25	**TOTAL ACCUMULATED DEPRECIATION**		2,041,533	1,386,133	0	655,400	0	0	1,386,133	975,625	207,423
RBD	26											
RBD	27											
RBD	28											
RBD	29	**NET ELECTRIC PLANT IN SERVICE**		5,152,095	3,681,174	0	1,470,922	0	0	3,681,174	2,491,959	746,440
RBD	30											
RBD	31											
RBD	32											
RBD	33											
RBD	34											
RBD	35											
RBD	36											
RBD	37											
RBD	38											
RBD	39											
RBD	40											
RBD	41											
RBD	42											
RBD	43											
RBD	44											

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBP	96												
RBP	97												
RBP	98												
RBP	99												
RBP	100												
RBD	1	**LESS: ACCUMULATED DEPRECIATION**											
RBD	2												
RBD	3	INTANGIBLE PLANT ACCUMULATED DEPRECIATIO	INTPLT	0	5,803	0	0	9,402	3,967	59,668	0	0	790
RBD	4												
RBD	5	TRANSMISSION PLANT ACCUMULATED DEPRECIA	TRANPLT	0	0	0	0	0	0	0	0	0	0
RBD	6												
RBD	7	DISTRIBUTION PLANT ACCUMULATED DEPRECIATION											
RBD	8	360-Land & Land Rights	PLT_360	0	0	0	0	0	0	0	0	0	0
RBD	9	361-Structures & Improvements	PLT_361	0	0	0	0	0	0	0	0	0	0
RBD	10	362-Station Equipment	PLT_362	0	0	0	0	0	0	0	0	0	0
RBD	11	364-Poles,Towers & Fixtures	PLT_364	0	0	0	0	43,942	0	0	0	0	0
RBD	12	365-Overhead Conductors & Devices	PLT_365	0	0	0	0	78,351	0	0	0	0	0
RBD	13	366-Underground Conduit	PLT_366	0	0	0	0	40,196	0	0	0	0	0
RBD	14	367-Underground Conductors & Devices	PLT_367	0	0	0	0	50,504	0	0	0	0	0
RBD	15	368-Line Transformers	PLT_368	0	196,182	0	0	0	0	0	0	0	0
RBD	16	369-Services	PLT_369	0	0	0	0	0	168,597	0	0	0	0
RBD	17	370-Meters	PLT_370	0	0	0	0	0	0	117,277	0	0	0
RBD	18	371-Installation on Customer Premises	PLT_371	0	0	0	0	0	0	0	0	0	7,907
RBD	19	373-Street Lighting & Signal Systems	PLT_373	0	0	0	0	0	0	0	0	0	35,370
RBD	20	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	0	186	0	0	302	127	102	0	0	25
RBD	21	TOTAL DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		0	196,368	0	0	213,296	168,725	117,379	0	0	43,303
RBD	22												
RBD	23	GENERAL PLANT ACCUMULATED DEPRECIATION	GENLPLT	0	915	0	0	10,451	478	1,935	21,580	1,173	3,254
RBD	24												
RBD	25	**TOTAL ACCUMULATED DEPRECIATION**		0	203,085	0	0	233,149	173,169	178,982	21,580	1,173	47,346
RBD	26												
RBD	27												
RBD	28												
RBD	29	**NET ELECTRIC PLANT IN SERVICE**		0	442,774	0	0	841,454	267,866	262,501	46,202	2,511	50,388
RBD	30												
RBD	31												
RBD	32												
RBD	33												
RBD	34												
RBD	35												
RBD	36												
RBD	37												
RBD	38												
RBD	39												
RBD	40												
RBD	41												
RBD	42												
RBD	43												
RBD	44												

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBD	45											
RBD	46											
RBD	47											
RBD	48											
RBD	49											
RBD	50											
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**										
RBO	2											
RBO	3	**PLUS: ADDITIONS TO RATE BASE**										
RBO	4											
RBO	5	COMMON PLANT	SALWAGES	326,144	158,084	0	168,061	0	0	158,084	112,772	41,357
RBO	6											
RBO	7	**WORKING CAPITAL**										
RBO	8	Purchased Power Cash Working Capital	SCH RBC, LN 33	19,631	0	19,631	0	0	0	0	0	0
RBO	9	Transmission Cash Working Capital	SCH RBC, LN 44	6,141	6,141	0	0	0	6,141	0	0	0
RBO	10	Distribution										
RBO	11	Cash Working Capital	SCH RBC, LN 18	123,280	75,321	1,059	46,901	0	6,048	69,272	50,468	14,765
RBO	12	Materials and Supplies	TOTPLT	15,876	11,183	0	4,693	0	0	11,183	7,653	2,105
RBO	13	Total Distribution Working Capital		139,156	86,504	1,059	51,594	0	6,048	80,456	58,120	16,870
RBO	14	TOTAL WORKING CAPITAL		164,928	92,645	20,689	51,594	0	12,189	80,456	58,120	16,870
RBO	15	TOTAL ADDITIONS TO RATE BASE		491,072	250,729	20,689	219,654	0	12,189	238,539	170,892	58,227
RBO	16											
RBO	17	**LESS: DEDUCTIONS TO RATE BASE**										
RBO	18	Customer Deposits	CUSTDEP	50,574	0	0	50,574	0	0	0	0	0
RBO	19	Customer Advances for Construction	CUSTADV	959	709	0	251	0	0	709	486	222
RBO	20	Deferred Income Taxes and Credits										
RBO	21	Plant	TOTPLT	986,701	695,048	0	291,653	0	0	695,048	475,625	130,835
RBO	22	Common Plant	SALWAGES	22,489	10,901	0	11,588	0	0	10,901	7,776	2,852
RBO	23	Pension Asset & OPEB Contribution	SALWAGES	(208,230)	(100,930)	0	(107,300)	0	0	(100,930)	(72,000)	(26,405)
RBO	24	Unamortized AMR Investment	CMETERS	(11,551)	0	0	(11,551)	0	0	0	0	0
RBO	25	Contributions in Aid of Construction (CIAC)	CUSTADV	(43,961)	(32,475)	0	(11,486)	0	0	(32,475)	(22,290)	(10,185)
RBO	26	Total Deferred Income Taxes and Credits		745,448	572,543	0	172,905	0	0	572,543	389,111	97,097
RBO	27	TOTAL DEDUCTIONS TO RATE BASE		796,981	573,252	0	223,729	0	0	573,252	389,597	97,319
RBO	28											
RBO	29											
RBO	30	Total Distribution Additions to Rate Base		465,301	244,588	1,059	219,654	0	6,048	238,539	170,892	58,227
RBO	31											
RBO	32	TOTAL PURCHASED POWER RATE BASE		19,631	0	19,631	0	0	0	0	0	0
RBO	33	TOTAL TRANSMSSION RATE BASE		6,141	6,141	0	0	0	6,141	0	0	0
RBO	34	TOTAL DSTRIBUTION RATE BASE		4,820,415	3,352,510	1,059	1,466,847	0	6,048	3,346,461	2,273,254	707,349
RBO	35											
RBO	36	**TOTAL RATE BASE**		4,846,186	3,358,651	20,689	1,466,847	0	12,189	3,346,461	2,273,254	707,349
RBO	37											
RBO	38											
RBO	39											
RBO	40											
RBO	41											
RBO	42											
RBO	43											

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
RBD	45												
RBD	46												
RBD	47												
RBD	48												
RBD	49												
RBD	50												
RBO	1	**ADDITIONS AND DEDUCTIONS TO RATE BASE**											
RBO	2												
RBO	3	**PLUS: ADDITIONS TO RATE BASE**											
RBO	4												
RBO	5	COMMON PLANT	SALWAGES	0	3,955	0	0	45,187	2,067	8,367	93,302	5,071	14,067
RBO	6												
RBO	7	**WORKING CAPITAL**											
RBO	8	Purchased Power Cash Working Capital	SCH RBC, LN 33	0	0	19,631	0	0	0	0	0	0	0
RBO	9	Transmission Cash Working Capital	SCH RBC, LN 44	0	0	0	0	0	0	0	0	0	0
RBO	10	Distribution											
RBO	11	Cash Working Capital	SCH RBC, LN 18	0	4,040	1,059	0	14,636	2,335	6,579	17,959	1,930	3,461
RBO	12	Materials and Supplies	TOTPLT	0	1,425	0	0	2,372	973	974	150	8	216
RBO	13	Total Distribution Working Capital		0	5,465	1,059	0	17,008	3,309	7,554	18,108	1,938	3,677
RBO	14	TOTAL WORKING CAPITAL		0	5,465	20,689	0	17,008	3,309	7,554	18,108	1,938	3,677
RBO	15	TOTAL ADDITIONS TO RATE BASE		0	9,420	20,689	0	62,195	5,375	15,920	111,411	7,009	17,744
RBO	16												
RBO	17	**LESS: DEDUCTIONS TO RATE BASE**											
RBO	18	Customer Deposits	CUSTDEP	0	0	0	0	0	0	0	0	0	50,574
RBO	19	Customer Advances for Construction	CUSTADV	0	0	0	0	251	0	0	0	0	0
RBO	20	Deferred Income Taxes and Credits											
RBO	21	Plant	TOTPLT	0	88,588	0	0	147,396	60,494	60,555	9,297	505	13,406
RBO	22	Common Plant	SALWAGES	0	273	0	0	3,116	143	577	6,434	350	970
RBO	23	Pension Asset & OPEB Contribution	SALWAGES	0	(2,525)	0	0	(28,850)	(1,320)	(5,342)	(59,570)	(3,238)	(8,981)
RBO	24	Unamortized AMR Investment	CMETERS	0	0	0	0	0	0	(11,551)	0	0	0
RBO	25	Contributions in Aid of Construction (CIAC)	CUSTADV	0	0	0	0	(11,486)	0	0	0	0	0
RBO	26	Total Deferred Income Taxes and Credits		0	86,336	0	0	110,176	59,317	44,240	(43,839)	(2,383)	5,394
RBO	27	TOTAL DEDUCTIONS TO RATE BASE		0	86,336	0	0	110,427	59,317	44,240	(43,839)	(2,383)	55,968
RBO	28												
RBO	29												
RBO	30	Total Distribution Additions to Rate Base		0	9,420	1,059	0	62,195	5,375	15,920	111,411	7,009	17,744
RBO	31												
RBO	32	TOTAL PURCHASED POWER RATE BASE		0	0	19,631	0	0	0	0	0	0	0
RBO	33	TOTAL TRANSMSSION RATE BASE		0	0	0	0	0	0	0	0	0	0
RBO	34	TOTAL DSTRIBUTION RATE BASE		0	365,858	1,059	0	793,222	213,924	234,182	201,452	11,903	12,164
RBO	35												
RBO	36	**TOTAL RATE BASE**		0	365,858	20,689	0	793,222	213,924	234,182	201,452	11,903	12,164
RBO	37												
RBO	38												
RBO	39												
RBO	40												
RBO	41												
RBO	42												
RBO	43												

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBO	44											
RBO	45											
RBO	46											
RBO	47											
RBO	48											
RBO	49											
RBO	50											
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	146,785	71,147	0	75,638	0	0	71,147	50,754	18,613
RBC	5	Pension	SALWAGES	13,055	6,328	0	6,727	0	0	6,328	4,514	1,655
RBC	6	Other Expenses	OMXPPPP	533,238	353,945	3,921	175,372	0	151,201	202,745	141,734	51,904
RBC	7	TOTAL EXPENSES		693,079	431,421	3,921	257,737	0	151,201	280,220	197,002	72,172
RBC	8	POR Working Capital	POR	1,062,743	721,595	8,942	332,207	0	1,815	719,779	544,793	130,638
RBC	9	TOTAL EXPENSES PER DAY		4,810	3,159	35	1,616	0	419	2,740	2,032	556
RBC	10											
RBC	11	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		67,948	44,620	498	22,830	0	5,922	38,699	28,706	7,848
RBC	12											
RBC	13	AVERAGE PREPAYMENTS		7,018	3,422	158	3,438	0	42	3,380	2,322	807
RBC	14	DISTRIBUTION ACCRUED TAXES		59,644	35,259	402	23,982	0	84	35,175	24,900	7,612
RBC	15	INTEREST PAYMENTS	TOTPLT	(11,330)	(7,981)	0	(3,349)	0	0	(7,981)	(5,462)	(1,502)
RBC	16											
RBC	17											
RBC	18	NET DISTRIBUIOTN CASH WORKING CAPITAL REQUIREMENT		123,280	75,321	1,059	46,901	0	6,048	69,272	50,468	14,765
RBC	19											
RBC	20											
RBC	21	**PURCHASED POWER**										
RBC	22	O&M EXPENSE RELATED CASH WORKING CAPITAL										
RBC	23	Commodity Purchased - Contract Purchases	ENERGY1	605,850	0	605,850	0	0	0	0	0	0
RBC	24	Commodity Purchased - Spot Market Purchases	ENERGY1	4,968	0	4,968	0	0	0	0	0	0
RBC	25	TOTAL EXPENSES		610,819	0	610,819	0	0	0	0	0	0
RBC	26											
RBC	27	TOTAL EXPENSES PER DAY		1,673	0	1,673	0	0	0	0	0	0
RBC	28											
RBC	29	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		19,631	0	19,631	0	0	0	0	0	0
RBC	30											
RBC	31	Energy ACCRUED TAXES	ENERGY1	0	0	0	0	0	0	0	0	0
RBC	32											
RBC	33	NET Energy CASH WORKING CAPITAL REQUIREMENT		19,631	0	19,631	0	0	0	0	0	0
RBC	34											
RBC	35	**TRANSMISSION**										
RBC	36	O&M EXPENSE - PJM Transmission Purchase	DTRAN	64,504	64,504	0	0	0	64,504	0	0	0
RBC	37											
RBC	38	TOTAL EXPENSES PER DAY		177	177	0	0	0	177	0	0	0
RBC	39											
RBC	40	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		6,141	6,141	0	0	0	6,141	0	0	0
RBC	41											
RBC	42	TRANSMISSION ACCRUED TAXES	DTRAN	0	0	0	0	0	0	0	0	0

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBO	44												
RBO	45												
RBO	46												
RBO	47												
RBO	48												
RBO	49												
RBO	50												
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	0	1,780	0	0	20,337	930	3,765	41,992	2,282	6,331
RBC	5	Pension	SALWAGES	0	158	0	0	1,809	83	335	3,735	203	563
RBC	6	Other Expenses	OMXPPPP	0	9,107	3,921	0	56,493	5,021	16,369	75,526	11,215	10,750
RBC	7	TOTAL EXPENSES		0	11,045	3,921	0	78,638	6,034	20,469	121,252	13,700	17,644
RBC	8	POR Working Capital	POR	0	44,349	8,942	0	104,950	27,931	57,691	117,879	12,107	11,648
RBC	9	TOTAL EXPENSES PER DAY		0	152	35	0	503	93	214	655	71	80
RBC	10												
RBC	11	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		0	2,144	498	0	7,105	1,314	3,025	9,254	999	1,134
RBC	12												
RBC	13	AVERAGE PREPAYMENTS		0	251	158	0	876	153	331	728	70	1,279
RBC	14	DISTRIBUTION ACCRUED TAXES		0	2,663	402	0	8,348	1,563	3,919	8,083	866	1,203
RBC	15	INTEREST PAYMENTS	TOTPLT	0	(1,017)	0	0	(1,693)	(695)	(695)	(107)	(6)	(154)
RBC	16												
RBC	17												
RBC	18	NET DISTRIBUIOTN CASH WORKING CAPITAL REQUIREMENT		0	4,040	1,059	0	14,636	2,335	6,579	17,959	1,930	3,461
RBC	19												
RBC	20												
RBC	21	**PURCHASED POWER**											
RBC	22	O&M EXPENSE RELATED CASH WORKING CAPITAL											
RBC	23	Commodity Purchased - Contract Purchases	ENERGY1	0	0	605,850	0	0	0	0	0	0	0
RBC	24	Commodity Purchased - Spot Market Purchases	ENERGY1	0	0	4,968	0	0	0	0	0	0	0
RBC	25	TOTAL EXPENSES		0	0	610,819	0	0	0	0	0	0	0
RBC	26												
RBC	27	TOTAL EXPENSES PER DAY		0	0	1,673	0	0	0	0	0	0	0
RBC	28												
RBC	29	PP CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		0	0	19,631	0	0	0	0	0	0	0
RBC	30												
RBC	31	Energy ACCRUED TAXES	ENERGY1	0	0	0	0	0	0	0	0	0	0
RBC	32												
RBC	33	NET Energy CASH WORKING CAPITAL REQUIREMENT		0	0	19,631	0	0	0	0	0	0	0
RBC	34												
RBC	35	**TRANSMISSION**											
RBC	36	O&M EXPENSE - PJM Transmission Purchase	DTRAN	0	0	0	0	0	0	0	0	0	0
RBC	37												
RBC	38	TOTAL EXPENSES PER DAY		0	0	0	0	0	0	0	0	0	0
RBC	39												
RBC	40	CWC REQUIREMENT (TOTAL EXPENSES x EXPENSE LAG)		0	0	0	0	0	0	0	0	0	0
RBC	41												
RBC	42	TRANSMISSION ACCRUED TAXES	DTRAN	0	0	0	0	0	0	0	0	0	0

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBC	43											
RBC	44	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT		6,141	6,141	0	0	0	6,141	0	0	0
RBC	45											
RBC	46											
RBC	47	NET TOTAL CASH WORKING CAPITAL REQUIREMENT		149,052	81,462	20,689	46,901	0	12,189	69,272	50,468	14,765
RBC	48											
RBC	49											
RBC	50											
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**										
RBC	2											
RBC	3	**LAG/LEAD DAYS**		**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**
RBC	4	REVENUE LAG DAYS	47.25									
RBC	5	EXPENSE LEAD DAYS	33.17	14.08	14.08	14.08	14.08	14.08	14.08	14.08	14.08	14.08
RBC	6	PURCHASED POWER REVENUE LAG DAYS	47.25									
RBC	7	PURCHASED POWER EXP LEAD DAYS	35.52	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73
RBC	8	TRANSMISSION REVENUE LAG DAYS	47.25									
RBC	9	TRANSMISSION EXP LEAD DAYS	12.50	34.75	34.75	34.75	34.75	34.75	34.75	34.75	34.75	34.75
RBC	10	DISTRIBUTION REVENUE LAG DAYS	47.25									
RBC	11	DISTRIBUTION LEAD DAYS	33.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13
RBC	12											
RBC	13											
RBC	14											
RBC	15											
RBC	16	DISTRIBUTION ACCRUED TAXES										
RBC	17	Federal Income Tax	EBT	505,781	353,800	132	151,848	0	754	353,046	240,429	75,606
RBC	18	State Income Tax	EBT	400,288	280,006	105	120,177	0	597	279,410	190,281	59,836
RBC	19	PURTA Taxes	PLT_3601	566,909	566,909	0	0	0	0	566,909	566,909	0
RBC	20	Capital Stock	CAPSTOCK	0	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	CLAIMREV	0	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	TOTPLT	336,616	237,118	0	99,498	0	0	237,118	162,261	44,635
RBC	23	PA Corp Loan Tax	TOTPLT	0	0	0	0	0	0	0	0	0
RBC	24	Philadelphia BPT	SALESREV	0	0	0	0	0	0	0	0	0
RBC	25	Local Privilege Tax	SALESREV	0	0	0	0	0	0	0	0	0
RBC	26	Gross Receipts Tax	SALESREV	19,960,466	11,431,871	146,649	8,381,945	0	29,486	11,402,386	7,928,740	2,598,263
RBC	27	Lag Day Weighted Accrued Taxes		21,770,060	12,869,705	146,886	8,753,469	0	30,836	12,838,869	9,088,620	2,778,340
RBC	28	Total Accrued Taxes CWC		59,644	35,259	402	23,982	0	84	35,175	24,900	7,612
RBC	29											
RBC	30	DISTRIBUTION AVERAGE PREPAYMENTS										
RBC	31	Call Center	CUST	20	0	0	20	0	0	0	0	0
RBC	32	EEI and EPRI Dues	CLAIMREV	438	196	131	111	0	37	159	110	36
RBC	33	PUC Assess - Electric	SALESREV	3,692	2,115	27	1,551	0	5	2,109	1,467	481
RBC	34	Prepaid Rents and Pole Attachment Fees	PLT_364	438	316	0	122	0	0	316	194	122
RBC	35	Prepaid Barrel Locks	CMETERS	0	0	0	0	0	0	0	0	0
RBC	36	SEPTA Duct Rentals	PLT_366	0	0	0	0	0	0	0	0	0
RBC	37	Philadelphia Work Permits	DISTPLT	0	0	0	0	0	0	0	0	0
RBC	38	Business Support System	CUST	334	0	0	334	0	0	0	0	0
RBC	39	VEBA Adjustment	SALWAGES	307	149	0	158	0	0	149	106	39
RBC	40	Facilities Contracts	DISTPLT	74	53	0	21	0	0	53	37	10
RBC	41	IT Service Contracts	TOTPLT	698	492	0	206	0	0	492	337	93

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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
RBC	43												
RBC	44	NET TRANSMISSION CASH WORKING CAPITAL REQUIREMENT		0	0	0	0	0	0	0	0	0	0
RBC	45												
RBC	46												
RBC	47	NET TOTAL CASH WORKING CAPITAL REQUIREMENT		0	4,040	20,689	0	14,636	2,335	6,579	17,959	1,930	3,461
RBC	48												
RBC	49												
RBC	50												
RBC	1	**CASH WORKING CAPITAL (LEAD LAG) CONTINUED**											
RBC	2												
RBC	3	**LAG/LEAD DAYS**		**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**	**NET DAYS**
RBC	4	REVENUE LAG DAYS	47.25										
RBC	5	EXPENSE LEAD DAYS	33.17	14.08	14.08	14.08	14.08	14.08	14.08	14.08	14.08	14.08	14.08
RBC	6	PURCHASED POWER REVENUE LAG DAYS	47.25										
RBC	7	PURCHASED POWER EXP LEAD DAYS	35.52	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73
RBC	8	TRANSMISSION REVENUE LAG DAYS	47.25										
RBC	9	TRANSMISSION EXP LEAD DAYS	12.50	34.75	34.75	34.75	34.75	34.75	34.75	34.75	34.75	34.75	34.75
RBC	10	DISTRIBUTION REVENUE LAG DAYS	47.25										
RBC	11	DISTRIBUTION LEAD DAYS	33.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13	14.13
RBC	12												
RBC	13												
RBC	14												
RBC	15												
RBC	16	DISTRIBUTION ACCRUED TAXES											
RBC	17	Federal Income Tax	EBT	0	37,012	132	0	81,800	21,849	22,696	23,322	1,357	824
RBC	18	State Income Tax	EBT	0	29,292	105	0	64,738	17,292	17,962	18,458	1,074	652
RBC	19	PURTA Taxes	PLT_3601	0	0	0	0	0	0	0	0	0	0
RBC	20	Capital Stock	CAPSTOCK	0	0	0	0	0	0	0	0	0	0
RBC	21	PA & Local Use Taxes	CLAIMREV	0	0	0	0	0	0	0	0	0	0
RBC	22	PA Property tax	TOTPLT	0	30,222	0	0	50,285	20,638	20,659	3,172	172	4,573
RBC	23	PA Corp Loan Tax	TOTPLT	0	0	0	0	0	0	0	0	0	0
RBC	24	Philadelphia BPT	SALESREV	0	0	0	0	0	0	0	0	0	0
RBC	25	Local Privilege Tax	SALESREV	0	0	0	0	0	0	0	0	0	0
RBC	26	Gross Receipts Tax	SALESREV	0	875,383	146,649	0	2,850,244	510,607	1,369,051	2,905,447	313,621	432,976
RBC	27	Lag Day Weighted Accrued Taxes		0	971,909	146,886	0	3,047,066	570,385	1,430,368	2,950,399	316,225	439,026
RBC	28	Total Accrued Taxes CWC		0	2,663	402	0	8,348	1,563	3,919	8,083	866	1,203
RBC	29												
RBC	30	DISTRIBUTION AVERAGE PREPAYMENTS											
RBC	31	Call Center	CUST	0	0	0	0	0	0	0	0	0	20
RBC	32	EEI and EPRI Dues	CLAIMREV	0	13	131	0	40	7	18	37	4	5
RBC	33	PUC Assess - Electric	SALESREV	0	162	27	0	527	94	253	537	58	80
RBC	34	Prepaid Rents and Pole Attachment Fees	PLT_364	0	0	0	0	122	0	0	0	0	0
RBC	35	Prepaid Barrel Locks	CMETERS	0	0	0	0	0	0	0	0	0	0
RBC	36	SEPTA Duct Rentals	PLT_366	0	0	0	0	0	0	0	0	0	0
RBC	37	Philadelphia Work Permits	DISTPLT	0	0	0	0	0	0	0	0	0	0
RBC	38	Business Support System	CUST	0	0	0	0	0	0	0	0	0	334
RBC	39	VEBA Adjustment	SALWAGES	0	4	0	0	43	2	8	88	5	13
RBC	40	Facilities Contracts	DISTPLT	0	7	0	0	11	5	4	0	0	1
RBC	41	IT Service Contracts	TOTPLT	0	63	0	0	104	43	43	7	0	9

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBC	42	Fleet Activities	GENLPLT	208	101	0	107	0	0	101	72	26
RBC	43	Billing and Research	CUSTBILLS	345	0	0	345	0	0	0	0	0
RBC	44	Postage	CUSTBILLS	461	0	0	461	0	0	0	0	0
RBC	45	TOTAL AVERAGE PREPAYMENTS		7,018	3,422	158	3,438	0	42	3,380	2,322	807
RBC	46											
RBC	47											
RBC	48											
RBC	49											
RBC	50											
RBC	51	**OPERATING REVENUES**										
RBC	52											
RBC	53	**SALES REVENUES**										
RBC	54	Sales of Electricity Revenues - Base		1,224,574	701,345	8,997	514,232	0	1,809	699,536	486,428	159,403
RBC	55	Sales of Electricity Revenues - Nuclear Decommissior	ENERGY2	(3,860)	0	(3,860)	0	0	0	0	0	0
RBC	56	Transmission Revenues	DTRANR	185,615	185,615	0	0	0	185,615	0	0	0
RBC	57	Purchased Electric Revenues	ENERGY1	653,769	0	653,769	0	0	0	0	0	0
RBC	58	TOTAL SALES OF ELECTRICITY		2,060,099	886,960	658,907	514,232	0	187,424	699,536	486,428	159,403
RBC	59											
RBC	60	**OTHER OPERATING REVENUES**										
RBC	61	Unbilled and Cost Adjustment Revenue	SALESREV	0	0	0	0	0	0	0	0	0
RBC	62	450-Forfeited Discounts	OX_904	9,406	4,716	64	4,626	0	13	4,704	2,980	1,289
RBC	63	454-Rent from Electric Property	PLT_364	17,832	12,870	0	4,962	0	0	12,870	7,896	4,973
RBC	64	456-Other Electric Revenues	DISTPLT	10,309	7,428	0	2,881	0	0	7,428	5,078	1,386
RBC	65	TOTAL OTHER OPERATING REV		37,547	25,014	64	12,469	0	13	25,002	15,954	7,648
RBC	66											
RBC	67	**TOTAL OPERATING REVENUES**		2,097,645	911,974	658,970	526,701	0	187,437	724,538	502,382	167,051
RBC	68											
RBC	69											
RBC	70											
RBC	71											
RBC	72											
RBC	73											
RBC	74											
RBC	75											
RBC	76											
RBC	77											
RBC	78											
RBC	79											
RBC	80											
RBC	81											
RBC	82											
RBC	83											
RBC	84											
RBC	85											
RBC	86											
RBC	87											
RBC	88											
RBC	89											
RBC	90											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
RBC	42	Fleet Activities	GENLPLT	0	3	0	0	29	1	5	60	3	9
RBC	43	Billing and Research	CUSTBILLS	0	0	0	0	0	0	0	0	0	345
RBC	44	Postage	CUSTBILLS	0	0	0	0	0	0	0	0	0	461
RBC	45	TOTAL AVERAGE PREPAYMENTS		0	251	158	0	876	153	331	728	70	1,279
RBC	46												
RBC	47												
RBC	48												
RBC	49												
RBC	50												
RBC	51	**OPERATING REVENUES**											
RBC	52												
RBC	53	**SALES REVENUES**											
RBC	54	Sales of Electricity Revenues - Base		0	53,705	8,997	0	174,862	31,326	83,991	178,249	19,241	26,563
RBC	55	Sales of Electricity Revenues - Nuclear Decommissior	ENERGY2	0	0	(3,860)	0	0	0	0	0	0	0
RBC	56	Transmission Revenues	DTRANR	0	0	0	0	0	0	0	0	0	0
RBC	57	Purchased Electric Revenues	ENERGY1	0	0	653,769	0	0	0	0	0	0	0
RBC	58	TOTAL SALES OF ELECTRICITY		0	53,705	658,907	0	174,862	31,326	83,991	178,249	19,241	26,563
RBC	59												
RBC	60	**OTHER OPERATING REVENUES**											
RBC	61	Unbilled and Cost Adjustment Revenue	SALESREV	0	0	0	0	0	0	0	0	0	0
RBC	62	450-Forfeited Discounts	OX_904	0	435	64	0	1,619	238	759	1,633	182	195
RBC	63	454-Rent from Electric Property	PLT_364	0	0	0	0	4,962	0	0	0	0	0
RBC	64	456-Other Electric Revenues	DISTPLT	0	964	0	0	1,563	659	527	0	0	131
RBC	65	TOTAL OTHER OPERATING REV		0	1,399	64	0	8,144	897	1,286	1,633	182	327
RBC	66												
RBC	67	**TOTAL OPERATING REVENUES**		0	55,104	658,970	0	183,006	32,223	85,277	179,882	19,423	26,890
RBC	68												
RBC	69												
RBC	70												
RBC	71												
RBC	72												
RBC	73												
RBC	74												
RBC	75												
RBC	76												
RBC	77												
RBC	78												
RBC	79												
RBC	80												
RBC	81												
RBC	82												
RBC	83												
RBC	84												
RBC	85												
RBC	86												
RBC	87												
RBC	88												
RBC	89												
RBC	90												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
RBC	91											
RBC	92											
RBC	93											
RBC	94											
RBC	95											
RBC	96											
RBC	97											
RBC	98											
RBC	99											
RBC	100											
E	1	**OPERATION & MAINTENANCE EXPENSE**										
E	2											
E	3	PRODUCTION EXPENSE										
E	4	Other Power Supply										
E	5	555 - Purchased Power - Capacity	ENERGY1	610,818	0	610,818	0	0	0	0	0	0
E	6	Total Other Power Supply		610,818	0	610,818	0	0	0	0	0	0
E	7	TOTAL PRODUCTION EXPENSE		610,818	0	610,818	0	0	0	0	0	0
E	8											
E	9	TRANSMISSION EXPENSES										
E	10	Operation Expense	DTRANR	172,218	172,218	0	0	0	172,218	0	0	0
E	11	Maintenance Expense	DTRAN	0	0	0	0	0	0	0	0	0
E	12	TOTAL TRANSMISSION EXPENSE		172,218	172,218	0	0	0	172,218	0	0	0
E	13											
E	14	DISTRIBUTION EXPENSES										
E	15	Operation										
E	16	580-Supervision	SALWAGDO	394	177	0	217	0	0	177	122	40
E	17	581-Load Dispatch	DISTPLT	46	33	0	13	0	0	33	23	6
E	18	582-Station Equipment	PLT_362	3,764	3,764	0	0	0	0	3,764	3,764	0
E	19	583-Overhead Lines	OHDIST	8,321	6,006	0	2,315	0	0	6,006	3,685	2,321
E	20	584-Underground Lines	UGDIST	7,521	5,702	0	1,819	0	0	5,702	4,365	1,337
E	21	585-Street Lighting	PLT_3713	0	0	0	0	0	0	0	0	0
E	22	586-Metering	CMETERS	10,978	0	0	10,978	0	0	0	0	0
E	23	587-Customer Installations	CUST	8,643	0	0	8,643	0	0	0	0	0
E	24	588-Miscellaneous	DISTPLT	52,563	37,875	0	14,688	0	0	37,875	25,893	7,065
E	25	589-Rents	DISTPLT	197	142	0	55	0	0	142	97	26
E	26	Total Distribution Operation		92,427	53,699	0	38,728	0	0	53,699	37,948	10,796
E	27											
E	28	Maintenance										
E	29	590-Supervision	SALWAGDM	0	0	0	0	0	0	0	0	0
E	30	591-Structures	PLT_361	7,342	7,342	0	0	0	0	7,342	7,342	0
E	31	592-Station Equipment	PLT_362	19,136	19,136	0	0	0	0	19,136	19,136	0
E	32	593-Overhead Lines	OHDIST	122,100	88,125	0	33,975	0	0	88,125	54,070	34,055
E	33	594-Underground Lines	UGDIST	34,939	26,488	0	8,451	0	0	26,488	20,275	6,212
E	34	595-Transformers	PLT_368	1,624	1,624	0	0	0	0	1,624	0	0
E	35	596-Street Lighting	PLT_373	1,830	0	0	1,830	0	0	0	0	0
E	36	597-Metering	CMETERS	0	0	0	0	0	0	0	0	0
E	37	598-Miscellaneous	DISTPLT	18,834	13,571	0	5,263	0	0	13,571	9,278	2,532
E	38	Total Distribution Maintenance		205,805	156,286	0	49,519	0	0	156,286	110,101	42,799
E	39											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
RBC	91												
RBC	92												
RBC	93												
RBC	94												
RBC	95												
RBC	96												
RBC	97												
RBC	98												
RBC	99												
RBC	100												
E	1	**OPERATION & MAINTENANCE EXPENSE**											
E	2												
E	3	PRODUCTION EXPENSE											
E	4	Other Power Supply											
E	5	555 - Purchased Power - Capacity	ENERGY1	0	0	610,818	0	0	0	0	0	0	0
E	6	Total Other Power Supply		0	0	610,818	0	0	0	0	0	0	0
E	7	TOTAL PRODUCTION EXPENSE		0	0	610,818	0	0	0	0	0	0	0
E	8												
E	9	TRANSMISSION EXPENSES											
E	10	Operation Expense	DTRANR	0	0	0	0	0	0	0	0	0	0
E	11	Maintenance Expense	DTRAN	0	0	0	0	0	0	0	0	0	0
E	12	TOTAL TRANSMISSION EXPENSE		0	0	0	0	0	0	0	0	0	0
E	13												
E	14	DISTRIBUTION EXPENSES											
E	15	Operation											
E	16	580-Supervision	SALWAGDO	0	15	0	0	46	10	59	0	0	103
E	17	581-Load Dispatch	DISTPLT	0	4	0	0	7	3	2	0	0	1
E	18	582-Station Equipment	PLT_362	0	0	0	0	0	0	0	0	0	0
E	19	583-Overhead Lines	OHDIST	0	0	0	0	2,315	0	0	0	0	0
E	20	584-Underground Lines	UGDIST	0	0	0	0	1,819	0	0	0	0	0
E	21	585-Street Lighting	PLT_3713	0	0	0	0	0	0	0	0	0	0
E	22	586-Metering	CMETERS	0	0	0	0	0	0	10,978	0	0	0
E	23	587-Customer Installations	CUST	0	0	0	0	0	0	0	0	0	8,643
E	24	588-Miscellaneous	DISTPLT	0	4,917	0	0	7,967	3,361	2,690	0	0	669
E	25	589-Rents	DISTPLT	0	18	0	0	30	13	10	0	0	3
E	26	Total Distribution Operation		0	4,955	0	0	12,185	3,387	13,738	0	0	9,418
E	27												
E	28	Maintenance											
E	29	590-Supervision	SALWAGDM	0	0	0	0	0	0	0	0	0	0
E	30	591-Structures	PLT_361	0	0	0	0	0	0	0	0	0	0
E	31	592-Station Equipment	PLT_362	0	0	0	0	0	0	0	0	0	0
E	32	593-Overhead Lines	OHDIST	0	0	0	0	33,975	0	0	0	0	0
E	33	594-Underground Lines	UGDIST	0	0	0	0	8,451	0	0	0	0	0
E	34	595-Transformers	PLT_368	0	1,624	0	0	0	0	0	0	0	0
E	35	596-Street Lighting	PLT_373	0	0	0	0	0	0	0	0	0	1,830
E	36	597-Metering	CMETERS	0	0	0	0	0	0	0	0	0	0
E	37	598-Miscellaneous	DISTPLT	0	1,762	0	0	2,855	1,204	964	0	0	240
E	38	Total Distribution Maintenance		0	3,386	0	0	45,281	1,204	964	0	0	2,070
E	39												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
E	40	TOTAL DISTRIBUTION PLANT O&M EXPENSES		298,232	209,985	0	88,247	0	0	209,985	148,049	53,595
E	41	TOTAL PURCHASED POWER O&M EXPENSES		610,818	0	610,818	0	0	0	0	0	0
E	42	TOTAL TRANSMISSION O&M EXPENSES		172,218	172,218	0	0	0	172,218	0	0	0
E	43											
E	44	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		1,081,268	382,203	610,818	88,247	0	172,218	209,985	148,049	53,595
E	45											
E	46											
E	47											
E	48											
E	49											
E	50											
E	51	**OPERATION & MAINTENANCE EXPENSE CONTINUED**										
E	52											
E	53	CUSTOMER ACCOUNTS EXPENSES										
E	54	901-Supervision	SALWAGCA	0	0	0	0	0	0	0	0	0
E	55	902-Meter Reading	CMETERS	572	0	0	572	0	0	0	0	0
E	56	903-Customer Records and Collection Expense	CUSTREC	71,133	0	0	71,133	0	0	0	0	0
E	57	904-Uncollectible Accounts	EXP_904	36,723	18,412	249	18,061	0	49	18,363	11,633	5,032
E	58	905-Miscellaneous CA	CUSTCAM	8,557	0	0	8,557	0	0	0	0	0
E	59	TOTAL CUSTOMER ACCTS EXPENSE		116,985	18,412	249	98,323	0	49	18,363	11,633	5,032
E	60											
E	61											
E	62	CUSTOMER SERVICE EXPENSES										
E	63	907-Supervision	SALWAGCS	0	0	0	0	0	0	0	0	0
E	64	908-Customer Assistance	CUSTASST	11,028	0	0	11,028	0	0	0	0	0
E	65	909-Informational Advertisement	CUSTADVT	885	0	0	885	0	0	0	0	0
E	66	910-Miscellaneous CS	CUSTCSM	149	0	0	149	0	0	0	0	0
E	67	TOTAL CUSTOMER SERVICE EXPENSE		12,062	0	0	12,062	0	0	0	0	0
E	68											
E	69	SALES EXPENSES TOTAL (ACCT 912 & 916)	CUSTSALES	883	0	0	883	0	0	0	0	0
E	70											
E	71	TOTAL OPER & MAINT EXCL A&G		1,211,198	400,615	611,068	199,515	0	172,268	228,347	159,681	58,627
E	72											
E	73	ADMINISTRATIVE & GENERAL EXPENSE										
E	74	920-Administrative Salaries	SALWAGES	40,687	19,721	0	20,966	0	0	19,721	14,069	5,159
E	75	921-Office Supplies & Expense	SALWAGES	8,660	4,198	0	4,463	0	0	4,198	2,995	1,098
E	76	923-Outside Service Employed	SALWAGES	78,835	38,211	0	40,623	0	0	38,211	27,259	9,997
E	77	924-Property Insurance	DGPLT	185	132	0	53	0	0	132	90	25
E	78	925-Injuries and Damages	SALWAGES	9,904	4,801	0	5,103	0	0	4,801	3,425	1,256
E	79	926-Employee Pensions & Benefits	SALWAGES	32,618	15,810	0	16,808	0	0	15,810	11,278	4,136
E	80	928-Regulatory Commission	CLAIMREV	12,684	5,668	3,796	3,221	0	1,067	4,601	3,187	1,040
E	81	929-Duplicate Charges-Credit	CLAIMREV	(1,496)	(669)	(448)	(380)	(0)	(126)	(543)	(376)	(123)
E	82	930-	CMETERS	0	0	0	0	0	0	0	0	0
E	83	930.2-Miscellaneous General	CLAIMREV	3,013	1,346	902	765	0	254	1,093	757	247
E	84	932-Maintenance of General Plant	GENLPLT	6,566	3,183	0	3,383	0	0	3,183	2,270	833
E	85	TOTAL A&G EXPENSE		191,655	92,400	4,249	95,006	0	1,195	91,206	64,953	23,668
E	86											
E	87	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**		619,817	320,797	4,498	294,521	0	1,244	319,553	224,635	82,295
E	88											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
E	40	TOTAL DISTRIBUTION PLANT O&M EXPENSES		0	8,341	0	0	57,466	4,591	14,702	0	0	11,488
E	41	TOTAL PURCHASED POWER O&M EXPENSES		0	0	610,818	0	0	0	0	0	0	0
E	42	TOTAL TRANSMISSION O&M EXPENSES		0	0	0	0	0	0	0	0	0	0
E	43												
E	44	TOTAL OPER & MAINT EXP (PROD,TRAN,& DIST)		0	8,341	610,818	0	57,466	4,591	14,702	0	0	11,488
E	45												
E	46												
E	47												
E	48												
E	49												
E	50												
E	51	**OPERATION & MAINTENANCE EXPENSE CONTINUED**											
E	52												
E	53	CUSTOMER ACCOUNTS EXPENSES											
E	54	901-Supervision	SALWAGCA	0	0	0	0	0	0	0	0	0	0
E	55	902-Meter Reading	CMETERS	0	0	0	0	0	0	572	0	0	0
E	56	903-Customer Records and Collection Expense	CUSTREC	0	0	0	0	0	0	0	71,133	0	0
E	57	904-Uncollectible Accounts	EXP_904	0	1,698	249	0	6,322	930	2,962	6,375	710	763
E	58	905-Miscellaneous CA	CUSTCAM	0	0	0	0	0	0	0	8,557	0	0
E	59	TOTAL CUSTOMER ACCTS EXPENSE		0	1,698	249	0	6,322	930	3,534	86,065	710	763
E	60												
E	61												
E	62	CUSTOMER SERVICE EXPENSES											
E	63	907-Supervision	SALWAGCS	0	0	0	0	0	0	0	0	0	0
E	64	908-Customer Assistance	CUSTASST	0	0	0	0	0	0	0	0	11,028	0
E	65	909-Informational Advertisement	CUSTADVT	0	0	0	0	0	0	0	0	885	0
E	66	910-Miscellaneous CS	CUSTCSM	0	0	0	0	0	0	0	0	149	0
E	67	TOTAL CUSTOMER SERVICE EXPENSE		0	0	0	0	0	0	0	0	12,062	0
E	68												
E	69	SALES EXPENSES TOTAL (ACCT 912 & 916)	CUSTSALES	0	0	0	0	0	0	0	0	883	0
E	70												
E	71	TOTAL OPER & MAINT EXCL A&G		0	10,039	611,068	0	63,788	5,521	18,236	86,065	13,655	12,250
E	72												
E	73	ADMINISTRATIVE & GENERAL EXPENSE											
E	74	920-Administrative Salaries	SALWAGES	0	493	0	0	5,637	258	1,044	11,640	633	1,755
E	75	921-Office Supplies & Expense	SALWAGES	0	105	0	0	1,200	55	222	2,478	135	374
E	76	923-Outside Service Employed	SALWAGES	0	956	0	0	10,922	500	2,022	22,553	1,226	3,400
E	77	924-Property Insurance	DGPLT	0	17	0	0	28	11	9	2	0	3
E	78	925-Injuries and Damages	SALWAGES	0	120	0	0	1,372	63	254	2,833	154	427
E	79	926-Employee Pensions & Benefits	SALWAGES	0	396	0	0	4,519	207	837	9,331	507	1,407
E	80	928-Regulatory Commission	CLAIMREV	0	373	3,796	0	1,152	215	526	1,062	113	153
E	81	929-Duplicate Charges-Credit	CLAIMREV	(0)	(44)	(448)	(0)	(136)	(25)	(62)	(125)	(13)	(18)
E	82	930-	CMETERS	0	0	0	0	0	0	0	0	0	0
E	83	930.2-Miscellaneous General	CLAIMREV	0	89	902	0	274	51	125	252	27	36
E	84	932-Maintenance of General Plant	GENLPLT	0	80	0	0	910	42	168	1,878	102	283
E	85	TOTAL A&G EXPENSE		0	2,584	4,249	0	25,878	1,376	5,145	51,904	2,883	7,820
E	86												
E	87	**TOTAL DISTIBUTION OPERATION & MAINTENANCE EXPENSES**		0	12,623	4,498	0	89,666	6,897	23,381	137,969	16,538	20,070
E	88												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
E	89	**TOTAL OPERATION & MAINTENANCE EXPENSES**		1,402,854	493,016	615,317	294,521	0	173,463	319,553	224,635	82,295
E	90											
E	91											
E	92											
E	93											
E	94											
E	95											
E	96											
E	97											
E	98											
E	99											
E	100											
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**										
D	2											
D	3	INTANGIBLE PLANT EXPENSE	INTPLT	17,560	6,622	0	10,938	0	0	6,622	4,527	1,235
D	4											
D	5	TRANSMISSION PLANT EXPENSE	TRANPLT	0	0	0	0	0	0	0	0	0
D	6											
D	7	DISTRIBUTION PLANT EXPENSE										
D	8	360-Land & Land Rights	PLT_360	0	0	0	0	0	0	0	0	0
D	9	361-Structures & Improvements	PLT_361	2,955	2,955	0	0	0	0	2,955	2,955	0
D	10	362-Station Equipment	PLT_362	22,856	22,856	0	0	0	0	22,856	22,856	0
D	11	364-Poles,Towers & Fixtures	PLT_364	16,268	11,742	0	4,527	0	0	11,742	7,204	4,537
D	12	365-Overhead Conductors & Devices	PLT_365	29,247	21,109	0	8,138	0	0	21,109	12,952	8,157
D	13	366-Underground Conduit	PLT_366	7,807	5,919	0	1,888	0	0	5,919	4,531	1,388
D	14	367-Underground Conductors & Devices	PLT_367	30,539	23,152	0	7,387	0	0	23,152	17,722	5,430
D	15	368-Line Transformers	PLT_368	14,280	14,280	0	0	0	0	14,280	0	0
D	16	369-Services	PLT_369	8,672	0	0	8,672	0	0	0	0	0
D	17	370-Meters and AMR Amortization	PLT_370	32,014	0	0	32,014	0	0	0	0	0
D	18	371-Installation on Customer Premises	PLT_371	5	0	0	5	0	0	0	0	0
D	19	373-Street Lighting & Signal Systems	PLT_373	1,852	0	0	1,852	0	0	0	0	0
D	20	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	0	0	0	0	0	0	0	0	0
D	21	TOTAL DISTRIBUTION PLANT EXPENSE		166,495	102,012	0	64,483	0	0	102,012	68,219	19,513
D	22											
D	23	GENERAL PLANT EXPENSE	GENLPLT	16,376	7,937	0	8,438	0	0	7,937	5,662	2,077
D	24											
D	25	COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	34,633	16,787	0	17,846	0	0	16,787	11,975	4,392
D	26											
D	27											
D	28	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		235,063	133,358	0	101,706	0	0	133,358	90,384	27,216
D	29											
D	30											
D	31											
D	32											
D	33											
D	34											
D	35											
D	36											
D	37											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
E	89	**TOTAL OPERATION & MAINTENANCE EXPENSES**		0	12,623	615,317	0	89,666	6,897	23,381	137,969	16,538	20,070
E	90												
E	91												
E	92												
E	93												
E	94												
E	95												
E	96												
E	97												
E	98												
E	99												
E	100												
D	1	**DEPRECIATION / AMORTIZATION EXPENSE**											
D	2												
D	3	INTANGIBLE PLANT EXPENSE	INTPLT	0	860	0	0	1,393	588	8,840	0	0	117
D	4												
D	5	TRANSMISSION PLANT EXPENSE	TRANPLT	0	0	0	0	0	0	0	0	0	0
D	6												
D	7	DISTRIBUTION PLANT EXPENSE											
D	8	360-Land & Land Rights	PLT_360	0	0	0	0	0	0	0	0	0	0
D	9	361-Structures & Improvements	PLT_361	0	0	0	0	0	0	0	0	0	0
D	10	362-Station Equipment	PLT_362	0	0	0	0	0	0	0	0	0	0
D	11	364-Poles,Towers & Fixtures	PLT_364	0	0	0	0	4,527	0	0	0	0	0
D	12	365-Overhead Conductors & Devices	PLT_365	0	0	0	0	8,138	0	0	0	0	0
D	13	366-Underground Conduit	PLT_366	0	0	0	0	1,888	0	0	0	0	0
D	14	367-Underground Conductors & Devices	PLT_367	0	0	0	0	7,387	0	0	0	0	0
D	15	368-Line Transformers	PLT_368	0	14,280	0	0	0	0	0	0	0	0
D	16	369-Services	PLT_369	0	0	0	0	0	8,672	0	0	0	0
D	17	370-Meters and AMR Amortization	PLT_370	0	0	0	0	0	0	32,014	0	0	0
D	18	371-Installation on Customer Premises	PLT_371	0	0	0	0	0	0	0	0	0	5
D	19	373-Street Lighting & Signal Systems	PLT_373	0	0	0	0	0	0	0	0	0	1,852
D	20	374-Asset Retirement Costs for Distribution Plant	DISTPLTXAR	0	0	0	0	0	0	0	0	0	0
D	21	TOTAL DISTRIBUTION PLANT EXPENSE		0	14,280	0	0	21,940	8,672	32,014	0	0	1,857
D	22												
D	23	GENERAL PLANT EXPENSE	GENLPLT	0	199	0	0	2,269	104	420	4,685	255	706
D	24												
D	25	COMMON PLANT DEPRECIATION/AMORTIZATION	SALWAGES	0	420	0	0	4,798	219	888	9,908	539	1,494
D	26												
D	27												
D	28	**TOTAL DEPRECIATION / AMORTIZATION EXPENSE**		0	15,758	0	0	30,401	9,583	42,163	14,592	793	4,174
D	29												
D	30												
D	31												
D	32												
D	33												
D	34												
D	35												
D	36												
D	37												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
D	38											
D	39											
D	40											
D	41											
D	42											
D	43											
D	44											
D	45											
D	46											
D	47											
D	48											
D	49											
D	50											
TO	1	**OTHER OPERATING EXPENSES**										
TO	2											
TO	3	**TAXES OTHER THAN INCOME TAXES**										
TO	4	**General Taxes**										
TO	5	PURTA Taxes	PLT_3601	5,286	5,286	0	0	0	0	5,286	5,286	0
TO	6	Capital Stock	CAPSTOCK	0	0	0	0	0	0	0	0	0
TO	7	Payroll Related	SALWAGES	10,564	5,120	0	5,444	0	0	5,120	3,653	1,340
TO	8	PA & Local Use Tax	CLAIMREV	350	157	105	89	0	29	127	88	29
TO	9	PA Property Tax	TOTPLT	4,357	3,069	0	1,288	0	0	3,069	2,100	578
TO	10	PA Corporate LoanTax	TOTPLT	0	0	0	0	0	0	0	0	0
TO	11	Total General Taxes		20,557	13,632	105	6,820	0	29	13,603	11,127	1,946
TO	12											
TO	13											
TO	14	**Gross Receipt Tax**										
TO	15											
TO	16	Purchased Power										
TO	17	Retail Revenue	SCH RBC, LN 57	653,769	0	653,769	0	0	0	0	0	0
TO	18	Forfeited Discounts		0	0	0	0	0	0	0	0	0
TO	19	Less: Bad Debt		0	0	0	0	0	0	0	0	0
TO	20	Total Purchased Power Revenue	CALCULATED	653,769	0	653,769	0	0	0	0	0	0
TO	21	Total Purchased Power @ GRT Rate 5.90%	CALCULATED	38,572	0	38,572	0	0	0	0	0	0
TO	22											
TO	23	Transmission										
TO	24	Retail Revenue	SCH RBC, LN 56	185,615	185,615	0	0	0	185,615	0	0	0
TO	25	Forfeited Discounts		0	0	0	0	0	0	0	0	0
TO	26	Less: Bad Debt		0	0	0	0	0	0	0	0	0
TO	27	Total Transmission Revenue	CALCULATED	185,615	185,615	0	0	0	185,615	0	0	0
TO	28	Total Transmission @ GRT Rate 5.90%	CALCULATED	10,951	10,951	0	0	0	10,951	0	0	0
TO	29											
TO	30	Distribution										
TO	31	Retail Revenue		1,224,574	701,345	8,997	514,232	0	1,809	699,536	486,428	159,403
TO	32	Forfeited Discounts	SCH RBC, LN 62	9,406	4,716	64	4,626	0	13	4,704	2,980	1,289
TO	33	Less: Bad Debt	SCH E, LN 57	36,723	18,412	249	18,061	0	49	18,363	11,633	5,032
TO	34	Total Distribution Revenue	CALCULATED	1,197,258	687,649	8,812	500,797	0	1,772	685,877	477,775	155,660
TO	35	Total Distribution @ GRT Rate 5.90%	CALCULATED	70,638	40,571	520	29,547	0	105	40,467	28,189	9,184
TO	36											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
D	38												
D	39												
D	40												
D	41												
D	42												
D	43												
D	44												
D	45												
D	46												
D	47												
D	48												
D	49												
D	50												
TO	1	**OTHER OPERATING EXPENSES**											
TO	2												
TO	3	**TAXES OTHER THAN INCOME TAXES**											
TO	4	**General Taxes**											
TO	5	PURTA Taxes	PLT_3601	0	0	0	0	0	0	0	0	0	0
TO	6	Capital Stock	CAPSTOCK	0	0	0	0	0	0	0	0	0	0
TO	7	Payroll Related	SALWAGES	0	128	0	0	1,464	67	271	3,022	164	456
TO	8	PA & Local Use Tax	CLAIMREV	0	10	105	0	32	6	15	29	3	4
TO	9	PA Property Tax	TOTPLT	0	391	0	0	651	267	267	41	2	59
TO	10	PA Corporate LoanTax	TOTPLT	0	0	0	0	0	0	0	0	0	0
TO	11	Total General Taxes		0	530	105	0	2,146	340	553	3,092	170	519
TO	12												
TO	13												
TO	14	**Gross Receipt Tax**											
TO	15												
TO	16	Purchased Power											
TO	17	Retail Revenue	SCH RBC, LN 57	0	0	653,769	0	0	0	0	0	0	0
TO	18	Forfeited Discounts		0	0	0	0	0	0	0	0	0	0
TO	19	Less: Bad Debt		0	0	0	0	0	0	0	0	0	0
TO	20	Total Purchased Power Revenue	CALCULATED	0	0	653,769	0	0	0	0	0	0	0
TO	21	Total Purchased Power @ GRT Rate 5.90%	CALCULATED	0	0	38,572	0	0	0	0	0	0	0
TO	22												
TO	23	Transmission											
TO	24	Retail Revenue	SCH RBC, LN 56	0	0	0	0	0	0	0	0	0	0
TO	25	Forfeited Discounts		0	0	0	0	0	0	0	0	0	0
TO	26	Less: Bad Debt		0	0	0	0	0	0	0	0	0	0
TO	27	Total Transmission Revenue	CALCULATED	0	0	0	0	0	0	0	0	0	0
TO	28	Total Transmission @ GRT Rate 5.90%	CALCULATED	0	0	0	0	0	0	0	0	0	0
TO	29												
TO	30	Distribution											
TO	31	Retail Revenue		0	53,705	8,997	0	174,862	31,326	83,991	178,249	19,241	26,563
TO	32	Forfeited Discounts	SCH RBC, LN 62	0	435	64	0	1,619	238	759	1,633	182	195
TO	33	Less: Bad Debt	SCH E, LN 57	0	1,698	249	0	6,322	930	2,962	6,375	710	763
TO	34	Total Distribution Revenue	CALCULATED	0	52,441	8,812	0	170,160	30,634	81,788	173,507	18,712	25,996
TO	35	Total Distribution @ GRT Rate 5.90%	CALCULATED	0	3,094	520	0	10,039	1,807	4,825	10,237	1,104	1,534
TO	36												

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
TO	37	Total Gross Receipts Tax		120,162	51,523	39,092	29,547	0	11,056	40,467	28,189	9,184
TO	38											
TO	39	TOTAL PURCHASED POWER TOIT EXPENSES		38,572	0	38,572	0	0	0	0	0	0
TO	40	TOTAL TRANSMISSION TOIT EXPENSES		10,951	10,951	0	0	0	10,951	0	0	0
TO	41	TOTAL DISTRIBUTION TOIT EXPENSES		91,196	54,203	625	36,367	0	134	54,069	39,316	11,130
TO	42											
TO	43	**TOTAL TAXES OTHER THAN INCOME**		140,719	65,155	39,197	36,367	0	11,085	54,069	39,316	11,130
TO	44											
TO	45											
TO	46											
TO	47											
TO	48											
TO	49											
TO	50											
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**										
TI	2											
TI	3	TOTAL DISTRIBUTION OPERATING REVENUES		1,258,261	726,359	5,201	526,701	0	1,822	724,538	502,382	167,051
TI	4	LESS:										
TI	5	OPERATION & MAINTAINENCE EXPENSE	SCH E, LN 87	619,817	320,797	4,498	294,521	0	1,244	319,553	224,635	82,295
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	SCH D, LN 28	235,063	133,358	0	101,706	0	0	133,358	90,384	27,216
TI	7	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 41	91,196	54,203	625	36,367	0	134	54,069	39,316	11,130
TI	8	NET OPERATING INCOME BEFORE TAXES		312,185	218,001	78	94,107	0	443	217,557	148,048	46,410
TI	9	LESS:										
TI	10	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of Debt)		93,491	65,021	21	28,449	0	117	64,904	44,089	13,719
TI	11											
TI	12	**BASE TAXABLE DISTRIBUTION INCOME**		218,695	152,980	57	65,658	0	326	152,654	103,959	32,691
TI	13											
TI	14											
TI	15	**CALCULATION OF PA STATE INCOME TAXES**										
TI	16	BASE TAXABLE INCOME	SCH TI, LN 12	218,695	152,980	57	65,658	0	326	152,654	103,959	32,691
TI	17	LESS:										
TI	18	State Tax Depreciation (Over) Under Book	TOTPLT	(19,825)	(13,965)	0	(5,860)	0	0	(13,965)	(9,556)	(2,629)
TI	19	Other Adjustment	TOTPLT	38,056	26,807	0	11,249	0	0	26,807	18,344	5,046
TI	20	Repair Allowance Deduction	TOTPLT	96,900	68,258	0	28,642	0	0	68,258	46,709	12,849
TI	21	PA STATE TAXALBE DISTRIBUTION INCOME		103,564	71,880	57	31,627	0	326	71,554	48,462	17,425
TI	22	**PA STATE INCOME TAXES @ Tax Rate 9.99%**		10,346	7,181	6	3,160	0	33	7,148	4,841	1,741
TI	23											
TI	24			0	0	0	0	0	0	0	0	0
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**										
TI	26	BASE TAXABLE INCOME	SCH TI, LN 12	218,695	152,980	57	65,658	0	326	152,654	103,959	32,691
TI	27	LESS:										
TI	28	PA State Income Taxes		10,346	7,181	6	3,160	0	33	7,148	4,841	1,741
TI	29	Federal Tax Depreciation (Over) Under Book	TOTPLT	(76,499)	(53,887)	0	(22,612)	0	0	(53,887)	(36,875)	(10,144)
TI	30	Other Adjustment	TOTPLT	38,056	26,807	0	11,249	0	0	26,807	18,344	5,046
TI	31	Repair Allowance Deduction	TOTPLT	96,900	68,258	0	28,642	0	0	68,258	46,709	12,849
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME		149,891	104,621	52	45,219	0	293	104,327	70,939	23,199
TI	33	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		31,477	21,970	11	9,496	0	62	21,909	14,897	4,872
TI	34											
TI	35	**PLUS:**										

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
TO	37	Total Gross Receipts Tax		0	3,094	39,092	0	10,039	1,807	4,825	10,237	1,104	1,534
TO	38												
TO	39	TOTAL PURCHASED POWER TOIT EXPENSES		0	0	38,572	0	0	0	0	0	0	0
TO	40	TOTAL TRANSMISSION TOIT EXPENSES		0	0	0	0	0	0	0	0	0	0
TO	41	TOTAL DISTRIBUTION TOIT EXPENSES		0	3,624	625	0	12,186	2,147	5,378	13,329	1,274	2,053
TO	42												
TO	43	**TOTAL TAXES OTHER THAN INCOME**		0	3,624	39,197	0	12,186	2,147	5,378	13,329	1,274	2,053
TO	44												
TO	45												
TO	46												
TO	47												
TO	48												
TO	49												
TO	50												
TI	1	**DEVELOPMENT OF DISTRIBUTION INCOME TAXES**											
TI	2												
TI	3	TOTAL DISTRIBUTION OPERATING REVENUES		0	55,104	5,201	0	183,006	32,223	85,277	179,882	19,423	26,890
TI	4	LESS:											
TI	5	OPERATION & MAINTAINENCE EXPENSE	SCH E, LN 87	0	12,623	4,498	0	89,666	6,897	23,381	137,969	16,538	20,070
TI	6	DEPRECIATION AND AMORTIZATION EXPENSE	SCH D, LN 28	0	15,758	0	0	30,401	9,583	42,163	14,592	793	4,174
TI	7	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 41	0	3,624	625	0	12,186	2,147	5,378	13,329	1,274	2,053
TI	8	NET OPERATING INCOME BEFORE TAXES		0	23,099	78	0	50,754	13,596	14,355	13,991	818	592
TI	9	LESS:											
TI	10	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of Debt)		0	7,096	21	0	15,384	4,149	4,542	3,907	231	236
TI	11												
TI	12	**BASE TAXABLE DISTRIBUTION INCOME**		0	16,004	57	0	35,369	9,447	9,813	10,084	587	356
TI	13												
TI	14												
TI	15	**CALCULATION OF PA STATE INCOME TAXES**											
TI	16	BASE TAXABLE INCOME	SCH TI, LN 12	0	16,004	57	0	35,369	9,447	9,813	10,084	587	356
TI	17	LESS:											
TI	18	State Tax Depreciation (Over) Under Book	TOTPLT	0	(1,780)	0	0	(2,962)	(1,215)	(1,217)	(187)	(10)	(269)
TI	19	Other Adjustment	TOTPLT	0	3,417	0	0	5,685	2,333	2,336	359	19	517
TI	20	Repair Allowance Deduction	TOTPLT	0	8,700	0	0	14,475	5,941	5,947	913	50	1,317
TI	21	PA STATE TAXALBE DISTRIBUTION INCOME		0	5,667	57	0	18,171	2,389	2,748	8,999	528	(1,208)
TI	22	**PA STATE INCOME TAXES @ Tax Rate 9.99%**		0	566	6	0	1,815	239	275	899	53	(121)
TI	23												
TI	24			0	0	0	0	0	0	0	0	0	0
TI	25	**CALCULATION OF FEDERAL INCOME TAXES**											
TI	26	BASE TAXABLE INCOME	SCH TI, LN 12	0	16,004	57	0	35,369	9,447	9,813	10,084	587	356
TI	27	LESS:											
TI	28	PA State Income Taxes		0	566	6	0	1,815	239	275	899	53	(121)
TI	29	Federal Tax Depreciation (Over) Under Book	TOTPLT	0	(6,868)	0	0	(11,428)	(4,690)	(4,695)	(721)	(39)	(1,039)
TI	30	Other Adjustment	TOTPLT	0	3,417	0	0	5,685	2,333	2,336	359	19	517
TI	31	Repair Allowance Deduction	TOTPLT	0	8,700	0	0	14,475	5,941	5,947	913	50	1,317
TI	32	FEDERAL TAXALBE DISTRIBUTION INCOME		0	10,189	52	0	24,822	5,625	5,951	8,634	504	(317)
TI	33	**FEDERAL INCOME TAXES @ Tax Rate 21.00%**		0	2,140	11	0	5,213	1,181	1,250	1,813	106	(67)
TI	34												
TI	35	**PLUS:**											

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
TI	36	**DEFERRED FEDERAL INCOME TAXES**										
TI	37	Federal Accelerated Depreciation (Over) Under Book	TOTPLT	(35,189)	(24,787)	0	(10,401)	0	0	(24,787)	(16,962)	(4,666)
TI	38	**DEFERRED FEDERAL INCOME TAXES @ Tax Rate 21.00%**		(7,390)	(5,205)	0	(2,184)	0	0	(5,205)	(3,562)	(980)
TI	39											
TI	40	**LESS:**										
TI	41	**OTHER TAX ADJUSTMENTS**										
TI	42	Electric Plant	TOTPLT	16	11	0	5	0	0	11	8	2
TI	43	Common Plant	SALWAGES	12	6	0	6	0	0	6	4	2
TI	44	Consolidated Income Tax Adjustment	EBT	0	0	0	0	0	0	0	0	0
TI	45	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**		24,059	16,748	11	7,301	0	62	16,686	11,323	3,888
TI	46											
TI	47	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**		34,406	23,929	17	10,460	0	94	23,835	16,165	5,629
TI	48											
TI	49											
TI	50											
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**										
TI	52											
TI	53	**DEVELOPMENT OF PURCHASED POWER TAXES**										
TI	54	PURCHASED POWER OPERATING REVENUES	SCH RBC, LN 57	653,769	0	653,769	0	0	0	0	0	0
TI	55	LESS:										
TI	56	OPERATION & MAINTAINENCE EXPENSE	SCH E, LN 41	610,818	0	610,818	0	0	0	0	0	0
TI	57	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 39	38,572	0	38,572	0	0	0	0	0	0
TI	58	NET OPERATING INCOME BEFORE TAXES		4,379	0	4,379	0	0	0	0	0	0
TI	59	LESS:										
TI	60	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of Debt)		381	0	381	0	0	0	0	0	0
TI	61	**BASE TAXABLE PURCHASED POWER INCOME**		3,998	0	3,998	0	0	0	0	0	0
TI	62	LESS:										
TI	63	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 9.99%**		399	0	399	0	0	0	0	0	0
TI	64	EQUALS:										
TI	65	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		756	0	756	0	0	0	0	0	0
TI	66	Additional Purchase Power Expense NOL		0	0	0	0	0	0	0	0	0
TI	67											
TI	68	**DEVELOPMENT OF TRANSMISSION TAXES**										
TI	69	TRANSMISSION OPERATING REVENUES	SCH RBC, LN 56	185,615	185,615	0	0	0	185,615	0	0	0
TI	70	LESS:										
TI	71	OPERATION & MAINTAINENCE EXPENSE	SCH E, LN 42	172,218	172,218	0	0	0	172,218	0	0	0
TI	72	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 40	10,951	10,951	0	0	0	10,951	0	0	0
TI	73	NET OPERATING INCOME BEFORE TAXES		2,445	2,445	0	0	0	2,445	0	0	0
TI	74	LESS:										
TI	75	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of Debt)		119	119	0	0	0	119	0	0	0
TI	76	**BASE TAXABLE TRANSMISSION INCOME**		2,326	2,326	0	0	0	2,326	0	0	0
TI	77	LESS:										
TI	78	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 9.99%**		232	232	0	0	0	232	0	0	0
TI	79	EQUALS:										
TI	80	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		440	440	0	0	0	440	0	0	0
TI	81											
TI	82	**TOTAL PA INCOME TAX EXPENSE**		10,978	7,413	405	3,160	0	265	7,148	4,841	1,741
TI	83	**TOTAL FEDERAL INCOME TAX EXPENSE**		25,255	17,188	767	7,301	0	501	16,686	11,323	3,888
TI	84	**TOTAL INCOME TAX EXPENSE**		36,233	24,601	1,172	10,460	0	766	23,835	16,165	5,629

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
TI	36	**DEFERRED FEDERAL INCOME TAXES**											
TI	37	Federal Accelerated Depreciation (Over) Under Book	TOTPLT	0	(3,159)	0	0	(5,257)	(2,157)	(2,160)	(332)	(18)	(478)
TI	38	**DEFERRED FEDERAL INCOME TAXES @ Tax Rate 21.00%**		0	(663)	0	0	(1,104)	(453)	(454)	(70)	(4)	(100)
TI	39												
TI	40	**LESS:**											
TI	41	**OTHER TAX ADJUSTMENTS**											
TI	42	Electric Plant	TOTPLT	0	1	0	0	2	1	1	0	0	0
TI	43	Common Plant	SALWAGES	0	0	0	0	2	0	0	4	0	1
TI	44	Consolidated Income Tax Adjustment	EBT	0	0	0	0	0	0	0	0	0	0
TI	45	**TOTAL DISTRIBUTION FEDERAL INCOME TAX EXPENSE**		0	1,475	11	0	4,105	727	795	1,740	102	(168)
TI	46												
TI	47	**TOTAL DISTRIBUTION INCOME TAX EXPENSE**		0	2,041	17	0	5,920	966	1,069	2,639	155	(288)
TI	48												
TI	49												
TI	50												
TI	51	**DEVELOPMENT OF INCOME TAXES CONTINUED**											
TI	52												
TI	53	**DEVELOPMENT OF PURCHASED POWER TAXES**											
TI	54	PURCHASED POWER OPERATING REVENUES	SCH RBC, LN 57	0	0	653,769	0	0	0	0	0	0	0
TI	55	LESS:											
TI	56	OPERATION & MAINTAINENCE EXPENSE	SCH E, LN 41	0	0	610,818	0	0	0	0	0	0	0
TI	57	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 39	0	0	38,572	0	0	0	0	0	0	0
TI	58	NET OPERATING INCOME BEFORE TAXES		0	0	4,379	0	0	0	0	0	0	0
TI	59	LESS:											
TI	60	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of Debt)		0	0	381	0	0	0	0	0	0	0
TI	61	**BASE TAXABLE PURCHASED POWER INCOME**		0	0	3,998	0	0	0	0	0	0	0
TI	62	LESS:											
TI	63	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 9.99%**		0	0	399	0	0	0	0	0	0	0
TI	64	EQUALS:											
TI	65	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		0	0	756	0	0	0	0	0	0	0
TI	66	Additional Purchase Power Expense NOL		0	0	0	0	0	0	0	0	0	0
TI	67												
TI	68	**DEVELOPMENT OF TRANSMISSION TAXES**											
TI	69	TRANSMISSION OPERATING REVENUES	SCH RBC, LN 56	0	0	0	0	0	0	0	0	0	0
TI	70	LESS:											
TI	71	OPERATION & MAINTAINENCE EXPENSE	SCH E, LN 42	0	0	0	0	0	0	0	0	0	0
TI	72	TAXES OTHER THAN INCOME TAXES	SCH TO, LN 40	0	0	0	0	0	0	0	0	0	0
TI	73	NET OPERATING INCOME BEFORE TAXES		0	0	0	0	0	0	0	0	0	0
TI	74	LESS:											
TI	75	INTEREST EXPENSE (Rate Base * 1.94% Weighted Cost of Debt)		0	0	0	0	0	0	0	0	0	0
TI	76	**BASE TAXABLE TRANSMISSION INCOME**		0	0	0	0	0	0	0	0	0	0
TI	77	LESS:											
TI	78	**PA STATE PURCHASED PWR INCOME TAXES @ Tax Rate 9.99%**		0	0	0	0	0	0	0	0	0	0
TI	79	EQUALS:											
TI	80	**FEDERAL PURCHASED PWR INCOME TAXES @ Tax Rate 21.00%**		0	0	0	0	0	0	0	0	0	0
TI	81												
TI	82	**TOTAL PA INCOME TAX EXPENSE**		0	566	405	0	1,815	239	275	899	53	(121)
TI	83	**TOTAL FEDERAL INCOME TAX EXPENSE**		0	1,475	767	0	4,105	727	795	1,740	102	(168)
TI	84	**TOTAL INCOME TAX EXPENSE**		0	2,041	1,172	0	5,920	966	1,069	2,639	155	(288)

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
TI	85											
TI	86											
TI	87											
TI	88											
TI	89	**TAX RATES**										
TI	90	GROSS RECEIPTS TAX RATE	5.90%									
TI	91	STATE TAX RATE	9.99%									
TI	92	UNCOLLECTIBLE EXPENSES	0.00886									
TI	93	FEDERAL TAX RATE - CURRENT	21.00%									
TI	94	PUC / OCA & SBA ASSESSMENT RATE	0.0036									
TI	95	EFFECTIVE TAX RATE	28.8921%									
TI	96	LPC RATE	0.004319									
TI	97	GROSS REVENUE CONVERSION FACTOR	1.507458									
TI	98	**WEIGHTED COST OF DEBT**	1.9395%									
TI	99											
TI	100											
SW	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**										
SW	2											
SW	3	**PRODUCTION OTHER SALARIES & WAGES EXPENSE**										
SW	4	555-Purchased Power	OX_PROD	0	0	0	0	0	0	0	0	0
SW	5	TOTAL PRODUCTION OTHER SAL & WAG EXP		0	0	0	0	0	0	0	0	0
SW	6											
SW	7	**TRANSMISSION SALARIES & WAGES EXPENSE**										
SW	8	Operation	OX_TRAN	0	0	0	0	0	0	0	0	0
SW	9	Maintenance	MX_TRAN	0	0	0	0	0	0	0	0	0
SW	10	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0
SW	11											
SW	12	**DISTRIBUTION SALARIES & WAGES EXPENSE**										
SW	13	Operation										
SW	14	583-Overhead Lines	OX_583	1,543	1,114	0	429	0	0	1,114	683	430
SW	15	584-Underground Lines	OX_584	2,041	1,547	0	494	0	0	1,547	1,184	363
SW	16	586-Metering	OX_586	2,111	0	0	2,111	0	0	0	0	0
SW	17	587-Customer Installations	OX_587	4,194	0	0	4,194	0	0	0	0	0
SW	18	588-Miscellaneous	OX_588	6,545	4,716	0	1,829	0	0	4,716	3,224	880
SW	19	Total Operation		16,433	7,377	0	9,056	0	0	7,377	5,092	1,673
SW	20	Maintenance										
SW	21	591-Structures	MX_591	1,232	1,232	0	0	0	0	1,232	1,232	0
SW	22	592-Station Equipment	MX_592	5,859	5,859	0	0	0	0	5,859	5,859	0
SW	23	593-Overhead Lines	MX_593	29,733	21,459	0	8,273	0	0	21,459	13,167	8,293
SW	24	594-Underground Lines	MX_594	14,345	10,875	0	3,470	0	0	10,875	8,325	2,551
SW	25	595-Transformers	MX_595	293	293	0	0	0	0	293	0	0
SW	26	596-Street Lighting	MX_596	99	0	0	99	0	0	0	0	0
SW	27	598-Miscellaneous	MX_598	3,616	2,606	0	1,011	0	0	2,606	1,781	486
SW	28	Total Maintenance		55,177	42,324	0	12,853	0	0	42,324	30,363	11,330
SW	29	TOTAL DISTRIBUTION		71,610	49,701	0	21,909	0	0	49,701	35,455	13,003
SW	30											
SW	31	**CUSTOMER ACCOUNTS SAL & WAGES EXP**										
SW	32	903-Customer Records and Collection Expense	CUSTREC	28,416	0	0	28,416	0	0	0	0	0
SW	33	905-Miscellaneous CA	CUSTCAM	918	0	0	918	0	0	0	0	0

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
TI	85												
TI	86												
TI	87												
TI	88												
TI	89	**TAX RATES**											
TI	90	GROSS RECEIPTS TAX RATE	5.90%										
TI	91	STATE TAX RATE	9.99%										
TI	92	UNCOLLECTIBLE EXPENSES	0.00886										
TI	93	FEDERAL TAX RATE - CURRENT	21.00%										
TI	94	PUC / OCA & SBA ASSESSMENT RATE	0.0036										
TI	95	EFFECTIVE TAX RATE	28.8921%										
TI	96	LPC RATE	0.004319										
TI	97	GROSS REVENUE CONVERSION FACTOR	1.507458										
TI	98	**WEIGHTED COST OF DEBT**	1.9395%										
TI	99												
TI	100												
SW	1	**DEVELOPMENT OF SALARIES & WAGES ALLOCATION FACTOR**											
SW	2												
SW	3	**PRODUCTION OTHER SALARIES & WAGES EXPENSE**											
SW	4	555-Purchased Power	OX_PROD	0	0	0	0	0	0	0	0	0	0
SW	5	TOTAL PRODUCTION OTHER SAL & WAG EXP		0	0	0	0	0	0	0	0	0	0
SW	6												
SW	7	**TRANSMISSION SALARIES & WAGES EXPENSE**											
SW	8	Operation	OX_TRAN	0	0	0	0	0	0	0	0	0	0
SW	9	Maintenance	MX_TRAN	0	0	0	0	0	0	0	0	0	0
SW	10	TOTAL TRANSMISSION		0	0	0	0	0	0	0	0	0	0
SW	11												
SW	12	**DISTRIBUTION SALARIES & WAGES EXPENSE**											
SW	13	Operation											
SW	14	583-Overhead Lines	OX_583	0	0	0	0	429	0	0	0	0	0
SW	15	584-Underground Lines	OX_584	0	0	0	0	494	0	0	0	0	0
SW	16	586-Metering	OX_586	0	0	0	0	0	0	2,111	0	0	0
SW	17	587-Customer Installations	OX_587	0	0	0	0	0	0	0	0	0	4,194
SW	18	588-Miscellaneous	OX_588	0	612	0	0	992	419	335	0	0	83
SW	19	Total Operation		0	612	0	0	1,915	419	2,445	0	0	4,277
SW	20	Maintenance											
SW	21	591-Structures	MX_591	0	0	0	0	0	0	0	0	0	0
SW	22	592-Station Equipment	MX_592	0	0	0	0	0	0	0	0	0	0
SW	23	593-Overhead Lines	MX_593	0	0	0	0	8,273	0	0	0	0	0
SW	24	594-Underground Lines	MX_594	0	0	0	0	3,470	0	0	0	0	0
SW	25	595-Transformers	MX_595	0	293	0	0	0	0	0	0	0	0
SW	26	596-Street Lighting	MX_596	0	0	0	0	0	0	0	0	0	99
SW	27	598-Miscellaneous	MX_598	0	338	0	0	548	231	185	0	0	46
SW	28	Total Maintenance		0	631	0	0	12,291	231	185	0	0	146
SW	29	TOTAL DISTRIBUTION		0	1,243	0	0	14,207	650	2,630	0	0	4,423
SW	30												
SW	31	**CUSTOMER ACCOUNTS SAL & WAGES EXP**											
SW	32	903-Customer Records and Collection Expense	CUSTREC	0	0	0	0	0	0	0	28,416	0	0
SW	33	905-Miscellaneous CA	CUSTCAM	0	0	0	0	0	0	0	918	0	0

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
SW	34	**TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP**		29,334	0	0	29,334	0	0	0	0	0
SW	35											
SW	36	**CUSTOMER SERVICE SAL & WAGES EXP**										
SW	37	908-Customer Assistance	CUSTASST	1,213	0	0	1,213	0	0	0	0	0
SW	38	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0	0
SW	39	910-Miscellaneous CS	CUSTCSM	7	0	0	7	0	0	0	0	0
SW	40	TOTAL CUSTOMER SERVICE SAL & WAGES EXP		1,219	0	0	1,219	0	0	0	0	0
SW	41											
SW	42	**SALES EXPENSE (ACCT 912&916)**	OX_CS	537	0	0	537	0	0	0	0	0
SW	43											
SW	44	**ADMINISTRATIVE & GENERAL SALARIES & WAGE**	SALWAGXAG	44,085	21,446	0	22,638	0	0	21,446	15,299	5,611
SW	45	**TOT OPER & MAINTENANCE LABOR**		146,785	71,147	0	75,638	0	0	71,147	50,754	18,613
SW	46											
SW	47											
SW	48											
SW	49											
SW	50											
AF	1	**ALLOCATION FACTOR TABLE**										
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
AF	3											
AF	4	**DEMAND**										
AF	5	DEMAND - PRODUCTION RELATED										
AF	6	Demand Production	DPROD	0.0000								
AF	7											
AF	8											
AF	9											
AF	10											
AF	11	DEMAND - TRANSMISSION RELATED										
AF	12	Demand Transmission (1 Coincident Peak)	DTRAN	8,141,078								
AF	13											
AF	14	Demand Transmission (Revenue)	DTRANR	185,615								
AF	15											
AF	16											
AF	17											
AF	18											
AF	19											
AF	20	DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand)										
AF	21	Demand Distribution Primary High Tension	DDISPHT	9,380,936								
AF	22	Demand Distribution Primary Overhead Lines	DDISTPOL	6,647,903								
AF	23	Demand Distribution Primary Underground Lines	DDISTPUL	6,647,903								
AF	24											
AF	25	Demand Distribution Secondary Overhead Lines	DDISTSOL	6,564,817								
AF	26	Demand Distribution Secondary Underground Lines	DDISTSUL	6,564,817								
AF	27	Demand Distribution Overhead Line Transformers	DDISTSOT	6,564,817								
AF	28	Demand Distribution Undergrnd Line Transformers	DDISTSUT	6,564,817								
AF	29											
AF	30											
AF	31											
AF	32											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
SW	34	**TOTAL CUSTOMER ACCOUNTS SAL & WAGES EXP**		0	0	0	0	0	0	0	29,334	0	0
SW	35												
SW	36	**CUSTOMER SERVICE SAL & WAGES EXP**											
SW	37	908-Customer Assistance	CUSTASST	0	0	0	0	0	0	0	0	1,213	0
SW	38	909-Advertisement	CUSTADVT	0	0	0	0	0	0	0	0	0	0
SW	39	910-Miscellaneous CS	CUSTCSM	0	0	0	0	0	0	0	0	7	0
SW	40	TOTAL CUSTOMER SERVICE SAL & WAGES EXP		0	0	0	0	0	0	0	0	1,219	0
SW	41												
SW	42	**SALES EXPENSE (ACCT 912&916)**	OX_CS	0	0	0	0	0	0	0	0	537	0
SW	43												
SW	44	**ADMINISTRATIVE & GENERAL SALARIES & WAGE**	SALWAGXAG	0	537	0	0	6,130	280	1,135	12,658	526	1,908
SW	45	**TOT OPER & MAINTENANCE LABOR**		0	1,780	0	0	20,337	930	3,765	41,992	2,282	6,331
SW	46												
SW	47												
SW	48												
SW	49												
SW	50												
AF	1	**ALLOCATION FACTOR TABLE**											
AF	2	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	3												
AF	4	**DEMAND**											
AF	5	DEMAND - PRODUCTION RELATED											
AF	6	Demand Production	DPROD										
AF	7												
AF	8												
AF	9												
AF	10												
AF	11	DEMAND - TRANSMISSION RELATED											
AF	12	Demand Transmission (1 Coincident Peak)	DTRAN										
AF	13												
AF	14	Demand Transmission (Revenue)	DTRANR										
AF	15												
AF	16												
AF	17												
AF	18												
AF	19												
AF	20	DEMAND - DISTRIBUTION RELATED (Non-Coincident Peak Demand)											
AF	21	Demand Distribution Primary High Tension	DDISPHT										
AF	22	Demand Distribution Primary Overhead Lines	DDISTPOL										
AF	23	Demand Distribution Primary Underground Lines	DDISTPUL										
AF	24												
AF	25	Demand Distribution Secondary Overhead Lines	DDISTSOL										
AF	26	Demand Distribution Secondary Underground Lines	DDISTSUL										
AF	27	Demand Distribution Overhead Line Transformers	DDISTSOT										
AF	28	Demand Distribution Undergrnd Line Transformers	DDISTSUT										
AF	29												
AF	30												
AF	31												
AF	32												

PECO Energy Company
Electric Class Cost of Service Study ($000)
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SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
AF	33											
AF	34											
AF	35											
AF	36											
AF	37											
AF	38											
AF	39											
AF	40											
AF	41											
AF	42											
AF	43											
AF	44											
AF	45											
AF	46											
AF	47											
AF	48											
AF	49											
AF	50											
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**										
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
AF	53											
AF	54	**ENERGY**										
AF	55	Energy Revenue at pro-forma adjusted level	ENERGY1	653,769								
AF	56	Energy @ Meter MWh Sales)	ENERGY2	37,430,876								
AF	57											
AF	58											
AF	59											
AF	60											
AF	61											
AF	62											
AF	63											
AF	64											
AF	65	**CUSTOMER**										
AF	66	364 & 365 - Cust. Dist. Secondary OH Lines (NCP)	CDISTSOL	6,564,817								
AF	67	366 & 367 - Cust. Dist. Secondary UG Lines (NCP)	CDISTSUL	6,564,817								
AF	66	364 & 366 - Cust. Dist. Secondary Poles, Towers, Fixtu	CDISTSOLC	1,690,712								
AF	67	365 & 367 - Cust. Dist. Secondary Conductors & Devic€	CDISTSULC	1,690,712								
AF	68											
AF	69	369-Services	CSERVICE	5,159,430								
AF	70	370-Meters	CMETERS	316,854								
AF	71	371-Installation on Customer Premises	CUSTPREM	1,690,712								
AF	72	373-Street Lighting & Signal Systems	CLIGHT	1								
AF	73											
AF	74	Customer Deposits	CUSTDEP	1.0000								
AF	75											
AF	76											
AF	77	903-Customer Records and Collections	CUSTREC	1.0000								
AF	78	905-Miscellaneous Customer Accounts	CUSTCAM	1,655,077								
AF	79	908-Customer Assistance	CUSTASST	1.0000								

PECO Energy Company
Electric Class Cost of Service Study ($000)
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AF	33												
AF	34												
AF	35												
AF	36												
AF	37												
AF	38												
AF	39												
AF	40												
AF	41												
AF	42												
AF	43												
AF	44												
AF	45												
AF	46												
AF	47												
AF	48												
AF	49												
AF	50												
AF	51	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	53												
AF	54	**ENERGY**											
AF	55	Energy Revenue at pro-forma adjusted level	ENERGY1										
AF	56	Energy @ Meter MWh Sales)	ENERGY2										
AF	57												
AF	58												
AF	59												
AF	60												
AF	61												
AF	62												
AF	63												
AF	64												
AF	65	**CUSTOMER**											
AF	66	364 & 365 - Cust. Dist. Secondary OH Lines (NCP)	CDISTSOL										
AF	67	366 & 367 - Cust. Dist. Secondary UG Lines (NCP)	CDISTSUL										
AF	66	364 & 366 - Cust. Dist. Secondary Poles, Towers, Fixtu	CDISTSOLC										
AF	67	365 & 367 - Cust. Dist. Secondary Conductors & Device	CDISTSULC										
AF	68												
AF	69	369-Services	CSERVICE										
AF	70	370-Meters	CMETERS										
AF	71	371-Installation on Customer Premises	CUSTPREM										
AF	72	373-Street Lighting & Signal Systems	CLIGHT										
AF	73												
AF	74	Customer Deposits	CUSTDEP										
AF	75												
AF	76												
AF	77	903-Customer Records and Collections	CUSTREC										
AF	78	905-Miscellaneous Customer Accounts	CUSTCAM										
AF	79	908-Customer Assistance	CUSTASST										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AF	80	909-Informational and Instructional Advertising	CUSTADVT	1,655,077								
AF	81	910-Miscellaneous Customer Service	CUSTCSM	1,655,077								
AF	82	916-Miscellaneous Sales Expense	CUSTSALES	1,655,077								
AF	83											
AF	84	Number of Bills	CUSTBILLS	19,860,923								
AF	85	Number of Customers	CUST	1,655,077								
AF	86	Number of Residential Customers	CUSTRES	1,487,872								
AF	87											
AF	90											
AF	91											
AF	92											
AF	93											
AF	94											
AF	95											
AF	96											
AF	97											
AF	98											
AF	99											
AF	100											
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**										
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
AF	103											
AF	104	**Plant Related**										
AF	105	Intangible Plant	INTPLT	175,650								
AF	106	Transmission Plant in Service	TRANPLT	0								
AF	107	Distribution Plant in Service	DISTPLT	6,781,042								
AF	108	General Plant in Service	GENLPLT	236,936								
AF	109	Total Electric Plant In Service	TOTPLT	7,193,628								
AF	110											
AF	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	6,779,149								
AF	112	Total Transmission and Distribution Plant	TDPLT	6,781,042								
AF	113	Total Distribution and General Plant	DGPLT	7,017,978								
AF	114	Rate Base	RATEBASE	4,846,186								
AF	115											
AF	116	Account 360	PLT_360	42,884								
AF	117	Account 361	PLT_361	139,261								
AF	118	Account 362	PLT_362	1,163,133								
AF	119	Account 364	PLT_364	754,022								
AF	120	Account 365	PLT_365	1,341,927								
AF	121	Account 366	PLT_366	464,223								
AF	122	Account 367	PLT_367	1,372,757								
AF	123	Account 368	PLT_368	634,209								
AF	124	Account 369	PLT_369	433,534								
AF	125	Account 370	PLT_370	346,878								
AF	126	Account 371	PLT_371	13,772								
AF	127	Account 373	PLT_373	72,548								
AF	128	Distribution Overhead Plant in Service	OHDIST	2,095,949								
AF	129	Distribution Underground Plant in Service	UGDIST	1,836,980								
AF	130	Accounts 360 & 361	PLT_3601	182,145								

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AF	80	909-Informational and Instructional Advertising	CUSTADVT										
AF	81	910-Miscellaneous Customer Service	CUSTCSM										
AF	82	916-Miscellaneous Sales Expense	CUSTSALES										
AF	83												
AF	84	Number of Bills	CUSTBILLS										
AF	85	Number of Customers	CUST										
AF	86	Number of Residential Customers	CUSTRES										
AF	87												
AF	90												
AF	91												
AF	92												
AF	93												
AF	94												
AF	95												
AF	96												
AF	97												
AF	98												
AF	99												
AF	100												
AF	101	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	103												
AF	104	**Plant Related**											
AF	105	Intangible Plant	INTPLT										
AF	106	Transmission Plant in Service	TRANPLT										
AF	107	Distribution Plant in Service	DISTPLT										
AF	108	General Plant in Service	GENLPLT										
AF	109	Total Electric Plant In Service	TOTPLT										
AF	110												
AF	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR										
AF	112	Total Transmission and Distribution Plant	TDPLT										
AF	113	Total Distribution and General Plant	DGPLT										
AF	114	Rate Base	RATEBASE										
AF	115												
AF	116	Account 360	PLT_360										
AF	117	Account 361	PLT_361										
AF	118	Account 362	PLT_362										
AF	119	Account 364	PLT_364										
AF	120	Account 365	PLT_365										
AF	121	Account 366	PLT_366										
AF	122	Account 367	PLT_367										
AF	123	Account 368	PLT_368										
AF	124	Account 369	PLT_369										
AF	125	Account 370	PLT_370										
AF	126	Account 371	PLT_371										
AF	127	Account 373	PLT_373										
AF	128	Distribution Overhead Plant in Service	OHDIST										
AF	129	Distribution Underground Plant in Service	UGDIST										
AF	130	Accounts 360 & 361	PLT_3601										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AF	131	Accounts 371 & 373	PLT_3713	86,320								
AF	132											
AF	133	Residential	DPLTRES	2,030,823								
AF	134	Residential Heating	DPLTRH	487,605								
AF	135	General Service	DPLTGS	753,038								
AF	136	Primary Distribution	DPLTPRID	29,051								
AF	137	High Tension	DPLTHT	546,256								
AF	138	Electric Propulsion	DPLTEP	34,722								
AF	139	Lighting	DPLTLCUST	51,435								
AF	140											
AF	141											
AF	142											
AF	143											
AF	144											
AF	145											
AF	146											
AF	147											
AF	148											
AF	149											
AF	150											
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**										
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
AF	153											
AF	154	**Production Expense Related**										
AF	155	Account 555	OX_555	610,818								
AF	156	O&M Expense Production Other	OX_PROD	610,818								
AF	157	Salaries and Wages Production Operation	SALWAGPO	0								
AF	158											
AF	159											
AF	160	**Transmission Expense Related**										
AF	161	Transmission Operation Expense	OX_TRAN	172,218								
AF	162	Transmission Maintenance Expense	MX_TRAN	0								
AF	163	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0								
AF	164	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0								
AF	165											
AF	166											
AF	167	**Distribution Expense Related**										
AF	168	Account 580	OX_580	394								
AF	169	Account 581	OX_581	46								
AF	170	Account 582	OX_582	3,764								
AF	171	Account 583	OX_583	8,321								
AF	172	Account 584	OX_584	7,521								
AF	173	Account 585	OX_585	0								
AF	174	Account 586	OX_586	10,978								
AF	175	Account 587	OX_587	8,643								
AF	176	Account 588	OX_588	52,563								
AF	177	Account 589	OX_589	197								
AF	178	Account 591	MX_591	7,342								
AF	179	Account 592	MX_592	19,136								

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
AF	131	Accounts 371 & 373	PLT_3713										
AF	132												
AF	133	Residential	DPLTRES										
AF	134	Residential Heating	DPLTRH										
AF	135	General Service	DPLTGS										
AF	136	Primary Distribution	DPLTPRID										
AF	137	High Tension	DPLTHT										
AF	138	Electric Propulsion	DPLTEP										
AF	139	Lighting	DPLTLCUST										
AF	140												
AF	141												
AF	142												
AF	143												
AF	144												
AF	145												
AF	146												
AF	147												
AF	148												
AF	149												
AF	150												
AF	151	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	153												
AF	154	**Production Expense Related**											
AF	155	Account 555	OX_555										
AF	156	O&M Expense Production Other	OX_PROD										
AF	157	Salaries and Wages Production Operation	SALWAGPO										
AF	158												
AF	159												
AF	160	**Transmission Expense Related**											
AF	161	Transmission Operation Expense	OX_TRAN										
AF	162	Transmission Maintenance Expense	MX_TRAN										
AF	163	Transmission Salaries & Wages Accounts 511-567	SALWAGTO										
AF	164	Transmission Salaries & Wages Accounts 569-574	SALWAGTM										
AF	165												
AF	166												
AF	167	**Distribution Expense Related**											
AF	168	Account 580	OX_580										
AF	169	Account 581	OX_581										
AF	170	Account 582	OX_582										
AF	171	Account 583	OX_583										
AF	172	Account 584	OX_584										
AF	173	Account 585	OX_585										
AF	174	Account 586	OX_586										
AF	175	Account 587	OX_587										
AF	176	Account 588	OX_588										
AF	177	Account 589	OX_589										
AF	178	Account 591	MX_591										
AF	179	Account 592	MX_592										

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
AF	180	Account 593	MX_593	122,100								
AF	181	Account 594	MX_594	34,939								
AF	182	Account 595	MX_595	1,624								
AF	183	Account 596	MX_596	1,830								
AF	184	Account 597	MX_597	0								
AF	185	Account 598	MX_598	18,834								
AF	186	O&M Accounts 581-589	OX_DIST	92,033								
AF	187	O&M Accounts 591-598	MX_DIST	205,805								
AF	188											
AF	189											
AF	190											
AF	191											
AF	192											
AF	193											
AF	194											
AF	195											
AF	196											
AF	197											
AF	198											
AF	199											
AF	200											
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**										
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
AF	203											
AF	204	**Customer Distribution Expense Related**										
AF	205	Account 902	OX_902	572								
AF	206	Account 903	OX_903	71,133								
AF	207	Account 904	OX_904	36,723								
AF	208	O&M Accounts 902-905	OX_CA	116,985								
AF	209											
AF	210	Account908	OX_908	11,028								
AF	211	Account909	OX_909	885								
AF	212	Account910	OX_910	149								
AF	213	O&M Accounts 908-910	OX_CS	12,062								
AF	214	Accounts 901-910	X_CACS	129,047								
AF	215											
AF	216	Total O&M less Purchased Power	OMXPP	791,152								
AF	217	Total O&M less PP less Payroll less Pension	OMXPPPP	611,750								
AF	218											
AF	219	**Salaries and Wages Expense Related**										
AF	220	Salaries & Wages Accounts 581-589	SALWAGDO	16,433								
AF	221	Salaries & Wages Accounts 591-598	SALWAGDM	55,177								
AF	222	Salaries & Wages Accounts 902-905	SALWAGCA	29,334								
AF	223	Salaries & Wages Accounts 908-910	SALWAGCS	1,219								
AF	224	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	102,164								
AF	225	Total Salaries and Wages Expense	SALWAGES	146,785								
AF	226											
AF	227	Base Taxable Income	EBT	218,695								
AF	228											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
AF	180	Account 593	MX_593										
AF	181	Account 594	MX_594										
AF	182	Account 595	MX_595										
AF	183	Account 596	MX_596										
AF	184	Account 597	MX_597										
AF	185	Account 598	MX_598										
AF	186	O&M Accounts 581-589	OX_DIST										
AF	187	O&M Accounts 591-598	MX_DIST										
AF	188												
AF	189												
AF	190												
AF	191												
AF	192												
AF	193												
AF	194												
AF	195												
AF	196												
AF	197												
AF	198												
AF	199												
AF	200												
AF	201	**ALLOCATION FACTOR TABLE CONTINUED**											
AF	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AF	203												
AF	204	**Customer Distribution Expense Related**											
AF	205	Account 902	OX_902										
AF	206	Account 903	OX_903										
AF	207	Account 904	OX_904										
AF	208	O&M Accounts 902-905	OX_CA										
AF	209												
AF	210	Account908	OX_908										
AF	211	Account909	OX_909										
AF	212	Account910	OX_910										
AF	213	O&M Accounts 908-910	OX_CS										
AF	214	Accounts 901-910	X_CACS										
AF	215												
AF	216	Total O&M less Purchased Power	OMXPP										
AF	217	Total O&M less PP less Payroll less Pension	OMXPPPP										
AF	218												
AF	219	**Salaries and Wages Expense Related**											
AF	220	Salaries & Wages Accounts 581-589	SALWAGDO										
AF	221	Salaries & Wages Accounts 591-598	SALWAGDM										
AF	222	Salaries & Wages Accounts 902-905	SALWAGCA										
AF	223	Salaries & Wages Accounts 908-910	SALWAGCS										
AF	224	Salaries & Wages Excluding Admin & Gen	SALWAGXAG										
AF	225	Total Salaries and Wages Expense	SALWAGES										
AF	226												
AF	227	Base Taxable Income	EBT										
AF	228												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AF	229											
AF	230											
AF	231											
AF	232											
AF	233											
AF	234											
AF	235											
AF	236											
AF	237											
AF	238											
AF	239											
AF	240											
AF	241											
AF	242											
AF	243											
AF	244											
AF	245											
AF	246											
AF	247											
AF	248											
AF	249											
AF	250											
AF	251	**REVENUES AND BILLING DETERMINANTS**										
AF	252											
AF	253	Base Rate Sales Revenue	SALESREV	1,224,574								
AF	254											
AF	255	Residential	SREVRES	681,075								
AF	256	Residential Heating	SREVRH	136,434								
AF	257	General Service	SREVGS	224,851								
AF	258	Primary Distribution	SREVPRID	8,178								
AF	259	High Tension	SREVHT	146,754								
AF	260	Electric Propulsion	SREVEP	7,207								
AF	261	Lighting	SREVLCUST	20,075								
AF	262											
AF	263											
AF	264											
AF	265											
AF	266	Claimed Rate Sales Revenue	CLAIMREV	2,206,473								
AF	267											
AF	268	Capital Stock	CAPSTOCK	4,700,051								
AF	269											
AF	270											
AF	271											
AF	272	**PRESENT REVENUES/EXPENSES FROM SALES INPUT**										
AF	273											
AF	274	Total Sales of Electricity Revenues		1,220,714								
AF	275	Sales of Electricity Revenues - Distribution		1,224,574								
AF	276	Sales of Electricity Revenues - Nuclear Decommissioning		(3,860)								
AF	277											

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
AF	229												
AF	230												
AF	231												
AF	232												
AF	233												
AF	234												
AF	235												
AF	236												
AF	237												
AF	238												
AF	239												
AF	240												
AF	241												
AF	242												
AF	243												
AF	244												
AF	245												
AF	246												
AF	247												
AF	248												
AF	249												
AF	250												
AF	251	**REVENUES AND BILLING DETERMINANTS**											
AF	252												
AF	253	Base Rate Sales Revenue	SALESREV										
AF	254												
AF	255	Residential	SREVRES										
AF	256	Residential Heating	SREVRH										
AF	257	General Service	SREVGS										
AF	258	Primary Distribution	SREVPRID										
AF	259	High Tension	SREVHT										
AF	260	Electric Propulsion	SREVEP										
AF	261	Lighting	SREVLCUST										
AF	262												
AF	263												
AF	264												
AF	265												
AF	266	Claimed Rate Sales Revenue	CLAIMREV										
AF	267												
AF	268	Capital Stock	CAPSTOCK										
AF	269												
AF	270												
AF	271												
AF	272	**PRESENT REVENUES/EXPENSES FROM SALES INPUT**											
AF	273												
AF	274	Total Sales of Electricity Revenues											
AF	275	Sales of Electricity Revenues - Distribution											
AF	276	Sales of Electricity Revenues - Nuclear Decommissioning											
AF	277												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AF	278											
AF	279											
AF	280	Sales of Electricity Revenues - Transmission		185,615								
AF	281											
AF	282											
AF	283	**BILLING DETERMINATE INPUTS**										
AF	284	Number of Customer Bills	SCH AF, LN 84	19,860,923								
AF	285	Annual MWh Sales @ Meter	SCH AF, LN 56	37,430,876								
AF	286	Annual MW - Billed		63,105								
AF	287											
AF	288											
AF	289	**RATE OF RETURN**										
AF	290	Rate of Return (Equalized)	SCH AF, LN 290	7.79%								
AF	291											
AF	292											
AF	293											
AF	294											
AF	295											
AF	296											
AF	297											
AF	298											
AF	299											
AF	300											
AP	1	**ALLOCATION PROPORTIONS TABLE**										
AP	2	**EXTERNALLY DEVELOPED ALLOCATION FACTOR**										
AP	3											
AP	4											
AP	5	DEMAND - PRODUCTION RELATED										
AP	6	Demand Production	DPROD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	7											
AP	8											
AP	9											
AP	10											
AP	11	DEMAND - TRANSMISSION RELATED										
AP	12	Demand Transmission (1 Coincident Peak)	DTRAN	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	13											
AP	14	Demand Transmission (Revenue)	DTRANR	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	15											
AP	16											
AP	17											
AP	18											
AP	19											
AP	20	DEMAND - DISTRIBUTION RELATED (Non-Coinciden										
AP	21	Demand Distribution Primary High Tension	DDISPHT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	22	Demand Distribution Primary Overhead Lines	DDISTPOL	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	1.00000
AP	23	Demand Distribution Primary Underground Lines	DDISTPUL	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	1.00000
AP	24											
AP	25	Demand Distribution Secondary Overhead Lines	DDISTSOL	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	26	Demand Distribution Secondary Underground Lines	DDISTSUL	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AF	278												
AF	279												
AF	280	Sales of Electricity Revenues - Transmission											
AF	281												
AF	282												
AF	283	**BILLING DETERMINATE INPUTS**											
AF	284	Number of Customer Bills	SCH AF, LN 84										
AF	285	Annual MWh Sales @ Meter	SCH AF, LN 56										
AF	286	Annual MW - Billed											
AF	287												
AF	288												
AF	289	**RATE OF RETURN**											
AF	290	Rate of Return (Equalized)	SCH AF, LN 290										
AF	291												
AF	292												
AF	293												
AF	294												
AF	295												
AF	296												
AF	297												
AF	298												
AF	299												
AF	300												
AP	1	**ALLOCATION PROPORTIONS TABLE**											
AP	2	**EXTERNALLY DEVELOPED ALLOCATION FACTOR**											
AP	3												
AP	4												
AP	5	DEMAND - PRODUCTION RELATED											
AP	6	Demand Production	DPROD	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	7												
AP	8												
AP	9												
AP	10												
AP	11	DEMAND - TRANSMISSION RELATED											
AP	12	Demand Transmission (1 Coincident Peak)	DTRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	13												
AP	14	Demand Transmission (Revenue)	DTRANR	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	15												
AP	16												
AP	17												
AP	18												
AP	19												
AP	20	DEMAND - DISTRIBUTION RELATED (Non-Coinciden											
AP	21	Demand Distribution Primary High Tension	DDISPHT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	22	Demand Distribution Primary Overhead Lines	DDISTPOL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	23	Demand Distribution Primary Underground Lines	DDISTPUL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	24												
AP	25	Demand Distribution Secondary Overhead Lines	DDISTSOL	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	26	Demand Distribution Secondary Underground Lines	DDISTSUL	1.00000	0.00000	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 ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AP	27	Demand Distribution Overhead Line Transformers	DDISTSOT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	28	Demand Distribution Undergrnd Line Transformers	DDISTSUT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	29											
AP	30											
AP	31											
AP	32											
AP	33											
AP	34											
AP	35											
AP	36											
AP	37											
AP	38											
AP	39											
AP	40											
AP	41											
AP	42											
AP	43											
AP	44											
AP	45											
AP	46											
AP	47											
AP	48											
AP	49											
AP	50											
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**										
AP	53											
AP	54	**ENERGY**										
AP	55	Energy Revenue at pro-forma adjusted level	ENERGY1	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	56	Energy @ Meter MWh Sales)	ENERGY2	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	57											
AP	58											
AP	59											
AP	60											
AP	61											
AP	62											
AP	63											
AP	64											
AP	65	**CUSTOMER**										
AP	66	364 & 365 - Cust. Dist. Secondary OH Lines (NCP)	CDISTSOL	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67	366 & 367 - Cust. Dist. Secondary UG Lines (NCP)	CDISTSUL	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	66	364 & 366 - Cust. Dist. Secondary Poles, Towers, Fixtu	CDISTSOLC	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67	365 & 367 - Cust. Dist. Secondary Conductors & Devic	CDISTSULC	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	68											
AP	69	369-Services	CSERVICE	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	70	370-Meters	CMETERS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	71	371-Installation on Customer Premises	CUSTPREM	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	72	373-Street Lighting & Signal Systems	CLIGHT	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	73											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AP	27	Demand Distribution Overhead Line Transformers	DDISTSOT	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	28	Demand Distribution Undergrnd Line Transformers	DDISTSUT	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	29												
AP	30												
AP	31												
AP	32												
AP	33												
AP	34												
AP	35												
AP	36												
AP	37												
AP	38												
AP	39												
AP	40												
AP	41												
AP	42												
AP	43												
AP	44												
AP	45												
AP	46												
AP	47												
AP	48												
AP	49												
AP	50												
AP	51	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	52	**EXTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	53												
AP	54	**ENERGY**											
AP	55	Energy Revenue at pro-forma adjusted level	ENERGY1	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	56	Energy @ Meter MWh Sales)	ENERGY2	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	57												
AP	58												
AP	59												
AP	60												
AP	61												
AP	62												
AP	63												
AP	64												
AP	65	**CUSTOMER**											
AP	66	364 & 365 - Cust. Dist. Secondary OH Lines (NCP)	CDISTSOL	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67	366 & 367 - Cust. Dist. Secondary UG Lines (NCP)	CDISTSUL	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	66	364 & 366 - Cust. Dist. Secondary Poles, Towers, Fixtu	CDISTSOLC	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	67	365 & 367 - Cust. Dist. Secondary Conductors & Device	CDISTSULC	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	68												
AP	69	369-Services	CSERVICE	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
AP	70	370-Meters	CMETERS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	71	371-Installation on Customer Premises	CUSTPREM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	72	373-Street Lighting & Signal Systems	CLIGHT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	73												

PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AP	74	Customer Deposits	CUSTDEP	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	75											
AP	76											
AP	77	903-Customer Records and Collections	CUSTREC	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	78	905-Miscellaneous Customer Accounts	CUSTCAM	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	79	908-Customer Assistance	CUSTASST	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	80	909-Informational and Instructional Advertising	CUSTADVT	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	81	910-Miscellaneous Customer Service	CUSTCSM	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	82	916-Miscellaneous Sales Expense	CUSTSALES	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	83											
AP	84	Number of Bills	CUSTBILLS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	85	Number of Customers	CUST	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	86	Number of Residential Customers	CUSTRES	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	87											
AP	90											
AP	91											
AP	92											
AP	93											
AP	94											
AP	95											
AP	96											
AP	97											
AP	98											
AP	99											
AP	100											
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
AP	103											
AP	104	**Plant Related**										
AP	105	Intangible Plant	INTPLT	1.00000	0.37710	0.00000	0.62290	0.00000	0.00000	0.37710	0.25780	0.07034
AP	106	Transmission Plant in Service	TRANPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	107	Distribution Plant in Service	DISTPLT	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	108	General Plant in Service	GENLPLT	1.00000	0.48470	0.00000	0.51530	0.00000	0.00000	0.48470	0.34577	0.12681
AP	109	Total Electric Plant In Service	TOTPLT	1.00000	0.70442	0.00000	0.29558	0.00000	0.00000	0.70442	0.48204	0.13260
AP	110											
AP	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	112	Total Transmission and Distribution Plant	TDPLT	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	113	Total Distribution and General Plant	DGPLT	1.00000	0.71261	0.00000	0.28739	0.00000	0.00000	0.71261	0.48765	0.13416
AP	114	Rate Base	RATEBASE	1.00000	0.69305	0.00427	0.30268	0.00000	0.00252	0.69053	0.46908	0.14596
AP	115											
AP	116	Account 360	PLT_360	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	117	Account 361	PLT_361	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	118	Account 362	PLT_362	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	119	Account 364	PLT_364	1.00000	0.72174	0.00000	0.27826	0.00000	0.00000	0.72174	0.44283	0.27891
AP	120	Account 365	PLT_365	1.00000	0.72174	0.00000	0.27826	0.00000	0.00000	0.72174	0.44283	0.27891
AP	121	Account 366	PLT_366	1.00000	0.75811	0.00000	0.24189	0.00000	0.00000	0.75811	0.58031	0.17781
AP	122	Account 367	PLT_367	1.00000	0.75811	0.00000	0.24189	0.00000	0.00000	0.75811	0.58031	0.17781
AP	123	Account 368	PLT_368	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	124	Account 369	PLT_369	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AP	74	Customer Deposits	CUSTDEP	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	75												
AP	76												
AP	77	903-Customer Records and Collections	CUSTREC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	78	905-Miscellaneous Customer Accounts	CUSTCAM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	79	908-Customer Assistance	CUSTASST	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	80	909-Informational and Instructional Advertising	CUSTADVT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	81	910-Miscellaneous Customer Service	CUSTCSM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	82	916-Miscellaneous Sales Expense	CUSTSALES	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	83												
AP	84	Number of Bills	CUSTBILLS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	85	Number of Customers	CUST	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	86	Number of Residential Customers	CUSTRES	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	87												
AP	90												
AP	91												
AP	92												
AP	93												
AP	94												
AP	95												
AP	96												
AP	97												
AP	98												
AP	99												
AP	100												
AP	101	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	102	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	103												
AP	104	**Plant Related**											
AP	105	Intangible Plant	INTPLT	0.00000	0.04896	0.00000	0.00000	0.07933	0.03347	0.50344	0.00000	0.00000	0.00666
AP	106	Transmission Plant in Service	TRANPLT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	107	Distribution Plant in Service	DISTPLT	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	108	General Plant in Service	GENLPLT	0.00000	0.01213	0.00000	0.00000	0.13855	0.00634	0.02565	0.28608	0.01555	0.04313
AP	109	Total Electric Plant In Service	TOTPLT	0.00000	0.08978	0.00000	0.00000	0.14938	0.06131	0.06137	0.00942	0.00051	0.01359
AP	110												
AP	111	Distribution Plant Excl Asset Retirement	DISTPLTXAR	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	112	Total Transmission and Distribution Plant	TDPLT	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	113	Total Distribution and General Plant	DGPLT	0.00000	0.09080	0.00000	0.00000	0.15114	0.06201	0.05031	0.00966	0.00052	0.01376
AP	114	Rate Base	RATEBASE	0.00000	0.07549	0.00427	0.00000	0.16368	0.04414	0.04832	0.04157	0.00246	0.00251
AP	115												
AP	116	Account 360	PLT_360	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	117	Account 361	PLT_361	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	118	Account 362	PLT_362	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	119	Account 364	PLT_364	0.00000	0.00000	0.00000	0.00000	0.27826	0.00000	0.00000	0.00000	0.00000	0.00000
AP	120	Account 365	PLT_365	0.00000	0.00000	0.00000	0.00000	0.27826	0.00000	0.00000	0.00000	0.00000	0.00000
AP	121	Account 366	PLT_366	0.00000	0.00000	0.00000	0.00000	0.24189	0.00000	0.00000	0.00000	0.00000	0.00000
AP	122	Account 367	PLT_367	0.00000	0.00000	0.00000	0.00000	0.24189	0.00000	0.00000	0.00000	0.00000	0.00000
AP	123	Account 368	PLT_368	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	124	Account 369	PLT_369	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AP	125	Account 370	PLT_370	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	126	Account 371	PLT_371	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	127	Account 373	PLT_373	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	128	Distribution Overhead Plant in Service	OHDIST	1.00000	0.72174	0.00000	0.27826	0.00000	0.00000	0.72174	0.44283	0.27891
AP	129	Distribution Underground Plant in Service	UGDIST	1.00000	0.75811	0.00000	0.24189	0.00000	0.00000	0.75811	0.58031	0.17781
AP	130	Accounts 360 & 361	PLT_3601	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	131	Accounts 371 & 373	PLT_3713	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	132											
AP	133	Residential	DPLTRES	1.00000	0.61078	0.00000	0.38922	0.00000	0.00000	0.61078	0.37134	0.23944
AP	134	Residential Heating	DPLTRH	1.00000	0.76655	0.00000	0.23345	0.00000	0.00000	0.76655	0.46605	0.30050
AP	135	General Service	DPLTGS	1.00000	0.87751	0.00000	0.12249	0.00000	0.00000	0.87751	0.53351	0.34400
AP	136	Primary Distribution	DPLTPRID	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.60798	0.39202
AP	137	High Tension	DPLTHT	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	138	Electric Propulsion	DPLTEP	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	139	Lighting	DPLTLCUST	1.00000	0.39651	0.00000	0.60349	0.00000	0.00000	0.39651	0.24107	0.15544
AP	140											
AP	141											
AP	142											
AP	143											
AP	144											
AP	145											
AP	146											
AP	147											
AP	148											
AP	149											
AP	150											
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
AP	153											
AP	154	**Production Expense Related**										
AP	155	Account 555	OX_555	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	156	O&M Expense Production Other	OX_PROD	1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	157	Salaries and Wages Production Operation	SALWAGPO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	158			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	159											
AP	160	**Transmission Expense Related**										
AP	161	Transmission Operation Expense	OX_TRAN	1.00000	1.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	162	Transmission Maintenance Expense	MX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	163	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	164	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	165											
AP	166											
AP	167	**Distribution Expense Related**										
AP	168	Account 580	OX_580	1.00000	0.44891	0.00000	0.55109	0.00000	0.00000	0.44891	0.30984	0.10181
AP	169	Account 581	OX_581	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	170	Account 582	OX_582	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	171	Account 583	OX_583	1.00000	0.72174	0.00000	0.27826	0.00000	0.00000	0.72174	0.44283	0.27891
AP	172	Account 584	OX_584	1.00000	0.75811	0.00000	0.24189	0.00000	0.00000	0.75811	0.58031	0.17781
AP	173	Account 585	OX_585	0.00000	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 ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
AP	125	Account 370	PLT_370	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	126	Account 371	PLT_371	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	127	Account 373	PLT_373	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	128	Distribution Overhead Plant in Service	OHDIST	0.00000	0.00000	0.00000	0.00000	0.27826	0.00000	0.00000	0.00000	0.00000	0.00000
AP	129	Distribution Underground Plant in Service	UGDIST	0.00000	0.00000	0.00000	0.00000	0.24189	0.00000	0.00000	0.00000	0.00000	0.00000
AP	130	Accounts 360 & 361	PLT_3601	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	131	Accounts 371 & 373	PLT_3713	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	132												
AP	133	Residential	DPLTRES	0.00000	0.00000	0.00000	0.00000	0.38922	0.00000	0.00000	0.00000	0.00000	0.00000
AP	134	Residential Heating	DPLTRH	0.00000	0.00000	0.00000	0.00000	0.23345	0.00000	0.00000	0.00000	0.00000	0.00000
AP	135	General Service	DPLTGS	0.00000	0.00000	0.00000	0.00000	0.12249	0.00000	0.00000	0.00000	0.00000	0.00000
AP	136	Primary Distribution	DPLTPRID	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	137	High Tension	DPLTHT	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	138	Electric Propulsion	DPLTEP	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	139	Lighting	DPLTLCUST	0.00000	0.00000	0.00000	0.00000	0.60349	0.00000	0.00000	0.00000	0.00000	0.00000
AP	140												
AP	141												
AP	142												
AP	143												
AP	144												
AP	145												
AP	146												
AP	147												
AP	148												
AP	149												
AP	150												
AP	151	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	152	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	153												
AP	154	**Production Expense Related**											
AP	155	Account 555	OX_555	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	156	O&M Expense Production Other	OX_PROD	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	157	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
AP	158			0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	159												
AP	160	**Transmission Expense Related**											
AP	161	Transmission Operation Expense	OX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	162	Transmission Maintenance Expense	MX_TRAN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	163	Transmission Salaries & Wages Accounts 511-567	SALWAGTO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	164	Transmission Salaries & Wages Accounts 569-574	SALWAGTM	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	165												
AP	166												
AP	167	**Distribution Expense Related**											
AP	168	Account 580	OX_580	0.00000	0.03726	0.00000	0.00000	0.11654	0.02547	0.14881	0.00000	0.00000	0.26027
AP	169	Account 581	OX_581	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	170	Account 582	OX_582	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	171	Account 583	OX_583	0.00000	0.00000	0.00000	0.00000	0.27826	0.00000	0.00000	0.00000	0.00000	0.00000
AP	172	Account 584	OX_584	0.00000	0.00000	0.00000	0.00000	0.24189	0.00000	0.00000	0.00000	0.00000	0.00000
AP	173	Account 585	OX_585	0.00000	0.00000	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 ($000)
For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AP	174	Account 586	OX_586	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	175	Account 587	OX_587	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	176	Account 588	OX_588	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	177	Account 589	OX_589	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	178	Account 591	MX_591	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	179	Account 592	MX_592	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	1.00000	0.00000
AP	180	Account 593	MX_593	1.00000	0.72174	0.00000	0.27826	0.00000	0.00000	0.72174	0.44283	0.27891
AP	181	Account 594	MX_594	1.00000	0.75811	0.00000	0.24189	0.00000	0.00000	0.75811	0.58031	0.17781
AP	182	Account 595	MX_595	1.00000	1.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	183	Account 596	MX_596	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	184	Account 597	MX_597	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	185	Account 598	MX_598	1.00000	0.72057	0.00000	0.27943	0.00000	0.00000	0.72057	0.49261	0.13441
AP	186	O&M Accounts 581-589	OX_DIST	1.00000	0.58155	0.00000	0.41845	0.00000	0.00000	0.58155	0.41100	0.11687
AP	187	O&M Accounts 591-598	MX_DIST	1.00000	0.75939	0.00000	0.24061	0.00000	0.00000	0.75939	0.53498	0.20796
AP	188											
AP	189											
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AP	194											
AP	195											
AP	196											
AP	197											
AP	198											
AP	199											
AP	200											
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**										
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**										
AP	203											
AP	204	**Customer Distribution Expense Related**										
AP	205	Account 902	OX_902	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	206	Account 903	OX_903	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	207	Account 904	OX_904	1.00000	0.50139	0.00678	0.49183	0.00000	0.00135	0.50004	0.31677	0.13702
AP	208	O&M Accounts 902-905	OX_CA	1.00000	0.15739	0.00213	0.84048	0.00000	0.00042	0.15697	0.09944	0.04301
AP	209											
AP	210	Account908	OX_908	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	211	Account909	OX_909	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	212	Account910	OX_910	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	213	O&M Accounts 908-910	OX_CS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	214	Accounts 901-910	X_CACS	1.00000	0.14268	0.00193	0.85539	0.00000	0.00038	0.14230	0.09014	0.03899
AP	215											
AP	216	Total O&M less Purchased Power	OMXPP	1.00000	0.62316	0.00569	0.37115	0.00000	0.21925	0.40391	0.28393	0.10402
AP	217	Total O&M less PP less Payroll less Pension	OMXPPPP	1.00000	0.66377	0.00735	0.32888	0.00000	0.28355	0.38021	0.26580	0.09734
AP	218											
AP	219	**Salaries and Wages Expense Related**										
AP	220	Salaries & Wages Accounts 581-589	SALWAGDO	1.00000	0.44891	0.00000	0.55109	0.00000	0.00000	0.44891	0.30984	0.10181
AP	221	Salaries & Wages Accounts 591-598	SALWAGDM	1.00000	0.76705	0.00000	0.23295	0.00000	0.00000	0.76705	0.55029	0.20533
AP	222	Salaries & Wages Accounts 902-905	SALWAGCA	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000

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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AP	174	Account 586	OX_586	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	175	Account 587	OX_587	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	176	Account 588	OX_588	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	177	Account 589	OX_589	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	178	Account 591	MX_591	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	179	Account 592	MX_592	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	180	Account 593	MX_593	0.00000	0.00000	0.00000	0.00000	0.27826	0.00000	0.00000	0.00000	0.00000	0.00000
AP	181	Account 594	MX_594	0.00000	0.00000	0.00000	0.00000	0.24189	0.00000	0.00000	0.00000	0.00000	0.00000
AP	182	Account 595	MX_595	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	183	Account 596	MX_596	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
AP	184	Account 597	MX_597	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	185	Account 598	MX_598	0.00000	0.09355	0.00000	0.00000	0.15158	0.06395	0.05117	0.00000	0.00000	0.01273
AP	186	O&M Accounts 581-589	OX_DIST	0.00000	0.05368	0.00000	0.00000	0.13190	0.03669	0.14864	0.00000	0.00000	0.10122
AP	187	O&M Accounts 591-598	MX_DIST	0.00000	0.01645	0.00000	0.00000	0.22002	0.00585	0.00468	0.00000	0.00000	0.01006
AP	188												
AP	189												
AP	190												
AP	191												
AP	192												
AP	193												
AP	194												
AP	195												
AP	196												
AP	197												
AP	198												
AP	199												
AP	200												
AP	201	**ALLOCATION PROPORTIONS TABLE CONTINUED**											
AP	202	**INTERNALLY DEVELOPED ALLOCATION FACTORS**											
AP	203												
AP	204	**Customer Distribution Expense Related**											
AP	205	Account 902	OX_902	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000
AP	206	Account 903	OX_903	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
AP	207	Account 904	OX_904	0.00000	0.04625	0.00678	0.00000	0.17216	0.02532	0.08065	0.17359	0.01934	0.02077
AP	208	O&M Accounts 902-905	OX_CA	0.00000	0.01452	0.00213	0.00000	0.05404	0.00795	0.03021	0.73569	0.00607	0.00652
AP	209												
AP	210	Account908	OX_908	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	211	Account909	OX_909	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	212	Account910	OX_910	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	213	O&M Accounts 908-910	OX_CS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	214	Accounts 901-910	X_CACS	0.00000	0.01316	0.00193	0.00000	0.04899	0.00721	0.02738	0.66693	0.09898	0.00591
AP	215												
AP	216	Total O&M less Purchased Power	OMXPP	0.00000	0.01596	0.00569	0.00000	0.11334	0.00872	0.02955	0.17439	0.01979	0.02537
AP	217	Total O&M less PP less Payroll less Pension	OMXPPPP	0.00000	0.01708	0.00735	0.00000	0.10594	0.00942	0.03070	0.14164	0.02103	0.02016
AP	218												
AP	219	**Salaries and Wages Expense Related**											
AP	220	Salaries & Wages Accounts 581-589	SALWAGDO	0.00000	0.03726	0.00000	0.00000	0.11654	0.02547	0.14881	0.00000	0.00000	0.26027
AP	221	Salaries & Wages Accounts 591-598	SALWAGDM	0.00000	0.01144	0.00000	0.00000	0.22276	0.00419	0.00335	0.00000	0.00000	0.00264
AP	222	Salaries & Wages Accounts 902-905	SALWAGCA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000

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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AP	223	Salaries & Wages Accounts 908-910	SALWAGCS	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	224	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	1.00000	0.48648	0.00000	0.51352	0.00000	0.00000	0.48648	0.34704	0.12727
AP	225	Total Salaries and Wages Expense	SALWAGES	1.00000	0.48470	0.00000	0.51530	0.00000	0.00000	0.48470	0.34577	0.12681
AP	226											
AP	227	Base Taxable Income	EBT	1.00000	0.69951	0.00026	0.30023	0.00000	0.00149	0.69802	0.47536	0.14948
AP	228											
AP	229											
AP	230											
AP	231											
AP	232											
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AP	234											
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AP	248											
AP	249											
AP	250											
AP	251	**REVENUES AND BILLING DETERMINANTS**										
AP	252											
AP	253	Base Rate Sales Revenue	SALESREV	1.00000	0.57273	0.00735	0.41993	0.00000	0.00148	0.57125	0.39722	0.13017
AP	254											
AP	255	Residential	SREVRES	1.00000	0.43784	0.00626	0.55590	0.00000	0.00124	0.43660	0.26977	0.12450
AP	256	Residential Heating	SREVRH	1.00000	0.60490	0.00819	0.38691	0.00000	0.00152	0.60338	0.37391	0.17329
AP	257	General Service	SREVGS	1.00000	0.74531	0.00701	0.24768	0.00000	0.00170	0.74361	0.45848	0.21095
AP	258	Primary Distribution	SREVPRID	1.00000	0.79465	0.00629	0.19906	0.00000	0.00138	0.79327	0.54322	0.25006
AP	259	High Tension	SREVHT	1.00000	0.91465	0.01290	0.07245	0.00000	0.00237	0.91227	0.91227	0.00000
AP	260	Electric Propulsion	SREVEP	1.00000	0.97673	0.00960	0.01367	0.00000	0.00207	0.97466	0.97466	0.00000
AP	261	Lighting	SREVLCUST	1.00000	0.26228	0.00138	0.73634	0.00000	0.00005	0.26223	0.16153	0.07421
AP	262											
AP	263											
AP	264											
AP	265											
AP	266	Claimed Rate Sales Revenue	CLAIMREV	1.00000	0.44684	0.29923	0.25393	0.00000	0.08414	0.36269	0.25127	0.08201
AP	267											
AP	268	Capital Stock	CAPSTOCK	1.00000	0.64395	0.07024	0.28581	0.00000	0.01975	0.62420	0.42787	0.12072
AP	269											
AP	270											
AP	271											

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AP	223	Salaries & Wages Accounts 908-910	SALWAGCS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000
AP	224	Salaries & Wages Excluding Admin & Gen	SALWAGXAG	0.00000	0.01217	0.00000	0.00000	0.13906	0.00636	0.02575	0.28713	0.01193	0.04329
AP	225	Total Salaries and Wages Expense	SALWAGES	0.00000	0.01213	0.00000	0.00000	0.13855	0.00634	0.02565	0.28608	0.01555	0.04313
AP	226												
AP	227	Base Taxable Income	EBT	0.00000	0.07318	0.00026	0.00000	0.16173	0.04320	0.04487	0.04611	0.00268	0.00163
AP	228												
AP	229												
AP	230												
AP	231												
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AP	233												
AP	234												
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AP	245												
AP	246												
AP	247												
AP	248												
AP	249												
AP	250												
AP	251	**REVENUES AND BILLING DETERMINANTS**											
AP	252												
AP	253	Base Rate Sales Revenue	SALESREV	0.00000	0.04386	0.00735	0.00000	0.14279	0.02558	0.06859	0.14556	0.01571	0.02169
AP	254												
AP	255	Residential	SREVRES	0.00000	0.04233	0.00626	0.00000	0.19784	0.02518	0.09013	0.19585	0.02216	0.02474
AP	256	Residential Heating	SREVRH	0.00000	0.05618	0.00819	0.00000	0.13138	0.01594	0.06187	0.14420	0.01647	0.01705
AP	257	General Service	SREVGS	0.00000	0.07417	0.00701	0.00000	0.07351	0.05237	0.05271	0.06715	0.00351	(0.00157)
AP	258	Primary Distribution	SREVPRID	0.00000	0.00000	0.00629	0.00000	0.00000	0.00416	0.04091	0.15126	0.00357	(0.00083)
AP	259	High Tension	SREVHT	0.00000	0.00000	0.01290	0.00000	0.00000	0.00132	0.01329	0.05244	0.00688	(0.00148)
AP	260	Electric Propulsion	SREVEP	0.00000	0.00000	0.00960	0.00000	0.00000	0.00000	0.00351	0.00441	0.00568	0.00007
AP	261	Lighting	SREVLCUST	0.00000	0.02649	0.00138	0.00000	0.28215	0.00000	0.00000	0.05597	0.00154	0.39668
AP	262												
AP	263												
AP	264												
AP	265												
AP	266	Claimed Rate Sales Revenue	CLAIMREV	0.00000	0.02941	0.29923	0.00000	0.09081	0.01695	0.04145	0.08374	0.00890	0.01208
AP	267												
AP	268	Capital Stock	CAPSTOCK	0.00000	0.07561	0.07024	0.00000	0.13563	0.05090	0.05669	0.02687	0.00248	0.01323
AP	269												
AP	270												
AP	271												

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
AP	272	**PRESENT REVENUES/EXPENSES FROM SALES IN**										
AP	273											
AP	274	Total Sales of Electricity Revenues		1.00000	1.00316	1.00000	1.00316	1.00316	1.00316	1.00316	1.00316	1.00316
AP	275	Sales of Electricity Revenues - Distribution		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	276	Sales of Electricity Revenues - Nuclear Decommissioni		1.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	277											
AP	278											
AP	279											
AP	280	Sales of Electricity Revenues - Transmission		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	281											
AP	282											
AP	283											
AP	284											
AP	285											
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AP	294											
AP	295											
AP	296											
AP	297											
AP	298											
AP	299											
AP	300											
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**										
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**										
ADA	3											
ADA	4	**Net Write-Offs**										
ADA	5	Residential	SREVRES	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611
ADA	6	Residential Heating	SREVRH	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148
ADA	7	General Service	SREVGS	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106
ADA	8	Primary Distribution	SREVPRID	95,948	95,948	95,948	95,948	95,948	95,948	95,948	95,948	95,948
ADA	9	High Tension	SREVHT	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968
ADA	10	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0	0
ADA	11	Lighting	SREVLCUST	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428
ADA	12											
ADA	13											
ADA	14	Total Write-Offs	EXP_904	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208
ADA	15											
ADA	16	Total Write-Offs	EXP_904	1.00000	0.50139	0.00678	0.49183	0.00000	0.00135	0.50004	0.31677	0.13702
ADA	17											
ADA	18	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0	0
ADA	19											
ADA	20											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
AP	272	**PRESENT REVENUES/EXPENSES FROM SALES IN**											
AP	273												
AP	274	Total Sales of Electricity Revenues		1.00316	1.00316	1.00000	1.00316	1.00316	1.00316	1.00316	1.00316	1.00316	1.00316
AP	275	Sales of Electricity Revenues - Distribution		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	276	Sales of Electricity Revenues - Nuclear Decommissioni		0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
AP	277												
AP	278												
AP	279												
AP	280	Sales of Electricity Revenues - Transmission		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
AP	281												
AP	282												
AP	283												
AP	284												
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AP	293												
AP	294												
AP	295												
AP	296												
AP	297												
AP	298												
AP	299												
AP	300												
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**											
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**											
ADA	3												
ADA	4	**Net Write-Offs**											
ADA	5	Residential	SREVRES	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611	67,155,611
ADA	6	Residential Heating	SREVRH	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148	15,223,148
ADA	7	General Service	SREVGS	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106	7,510,106
ADA	8	Primary Distribution	SREVPRID	95,948	95,948	95,948	95,948	95,948	95,948	95,948	95,948	95,948	95,948
ADA	9	High Tension	SREVHT	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968	2,018,968
ADA	10	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0	0	0
ADA	11	Lighting	SREVLCUST	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428	11,428
ADA	12												
ADA	13												
ADA	14	Total Write-Offs	EXP_904	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208	92,015,208
ADA	15												
ADA	16	Total Write-Offs	EXP_904	0.00000	0.04625	0.00678	0.00000	0.17216	0.02532	0.08065	0.17359	0.01934	0.02077
ADA	17												
ADA	18	Additional Net Write-Offs at Claimed Rate	EXP_904	0	0	0	0	0	0	0	0	0	0
ADA	19												
ADA	20												

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL ELECTRIC DIVISION	DEMAND	ENERGY	CUSTOMER	PRODUCTION	TRANSMISSION	DISTRIBUTION	DEMDISPHT	DEMDISPRI
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
ADA	21											
ADA	22	**Customer Advances for Construction**										
ADA	23	Residential	DPLTRES	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823
ADA	24	Residential Heating	DPLTRH	487,605	487,605	487,605	487,605	487,605	487,605	487,605	487,605	487,605
ADA	25	General Service	DPLTGS	753,038	753,038	753,038	753,038	753,038	753,038	753,038	753,038	753,038
ADA	26	Primary Distribution	DPLTPRID	29,051	29,051	29,051	29,051	29,051	29,051	29,051	29,051	29,051
ADA	27	High Tension	DPLTHT	546,256	546,256	546,256	546,256	546,256	546,256	546,256	546,256	546,256
ADA	28	Electric Propulsion	DPLTEP	34,722	34,722	34,722	34,722	34,722	34,722	34,722	34,722	34,722
ADA	29	Lighting	DPLTLCUST	51,435	51,435	51,435	51,435	51,435	51,435	51,435	51,435	51,435
ADA	30											
ADA	31											
ADA	32	Customer Advances for Construction	CUSTADV	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929
ADA	33											
ADA	34	Customer Advances for Construction	CUSTADV	1.00000	0.73873	0.00000	0.26127	0.00000	0.00000	0.73873	0.50704	0.23169
ADA	35											
ADA	36											
ADA	37	**Purchase of Receivables**										
ADA	38	Residential	SREVRES	337,427	337,427	337,427	337,427	337,427	337,427	337,427	337,427	337,427
ADA	39	Residential Heating	SREVRH	87,289	87,289	87,289	87,289	87,289	87,289	87,289	87,289	87,289
ADA	40	General Service	SREVGS	336,728	336,728	336,728	336,728	336,728	336,728	336,728	336,728	336,728
ADA	41	Primary Distribution	SREVPRID	7,805	7,805	7,805	7,805	7,805	7,805	7,805	7,805	7,805
ADA	42	High Tension	SREVHT	286,508	286,508	286,508	286,508	286,508	286,508	286,508	286,508	286,508
ADA	43	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0	0
ADA	44	Lighting	SREVLCUST	6,987	6,987	6,987	6,987	6,987	6,987	6,987	6,987	6,987
ADA	45											
ADA	46											
ADA	47	Total POR	POR	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743
ADA	48											
ADA	49	Total POR	POR	1.00000	0.67899	0.00841	0.31259	0.00000	0.00171	0.67728	0.51263	0.12293
ADA	50											
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**										
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**										
ADA	3											
ADA	4	**AVAILABLE**										
ADA	5	Residential	SREVRES	0	0	0	0	0	0	0	0	0
ADA	6	Residential Heating	SREVRH	0	0	0	0	0	0	0	0	0
ADA	7	General Service	SREVGS	0	0	0	0	0	0	0	0	0
ADA	8	Primary Distribution	SREVPRID	0	0	0	0	0	0	0	0	0
ADA	9	High Tension	SREVHT	0	0	0	0	0	0	0	0	0
ADA	10	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0	0
ADA	11	Lighting	SREVLCUST	0	0	0	0	0	0	0	0	0
ADA	12											
ADA	13											
ADA	14											
ADA	15	Total Available	SREVAVAIL	0	0	0	0	0	0	0	0	0
ADA	16											
ADA	17	Total Available	SREVAVAIL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ADA	18											
ADA	19											

PECO Energy Company
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SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
ADA	21												
ADA	22	**Customer Advances for Construction**											
ADA	23	Residential	DPLTRES	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823	2,030,823
ADA	24	Residential Heating	DPLTRH	487,605	487,605	487,605	487,605	487,605	487,605	487,605	487,605	487,605	487,605
ADA	25	General Service	DPLTGS	753,038	753,038	753,038	753,038	753,038	753,038	753,038	753,038	753,038	753,038
ADA	26	Primary Distribution	DPLTPRID	29,051	29,051	29,051	29,051	29,051	29,051	29,051	29,051	29,051	29,051
ADA	27	High Tension	DPLTHT	546,256	546,256	546,256	546,256	546,256	546,256	546,256	546,256	546,256	546,256
ADA	28	Electric Propulsion	DPLTEP	34,722	34,722	34,722	34,722	34,722	34,722	34,722	34,722	34,722	34,722
ADA	29	Lighting	DPLTLCUST	51,435	51,435	51,435	51,435	51,435	51,435	51,435	51,435	51,435	51,435
ADA	30												
ADA	31												
ADA	32	Customer Advances for Construction	CUSTADV	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929	3,932,929
ADA	33												
ADA	34	Customer Advances for Construction	CUSTADV	0.00000	0.00000	0.00000	0.00000	0.26127	0.00000	0.00000	0.00000	0.00000	0.00000
ADA	35												
ADA	36												
ADA	37	**Purchase of Receivables**											
ADA	38	Residential	SREVRES	337,427	337,427	337,427	337,427	337,427	337,427	337,427	337,427	337,427	337,427
ADA	39	Residential Heating	SREVRH	87,289	87,289	87,289	87,289	87,289	87,289	87,289	87,289	87,289	87,289
ADA	40	General Service	SREVGS	336,728	336,728	336,728	336,728	336,728	336,728	336,728	336,728	336,728	336,728
ADA	41	Primary Distribution	SREVPRID	7,805	7,805	7,805	7,805	7,805	7,805	7,805	7,805	7,805	7,805
ADA	42	High Tension	SREVHT	286,508	286,508	286,508	286,508	286,508	286,508	286,508	286,508	286,508	286,508
ADA	43	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0	0	0
ADA	44	Lighting	SREVLCUST	6,987	6,987	6,987	6,987	6,987	6,987	6,987	6,987	6,987	6,987
ADA	45												
ADA	46												
ADA	47	Total POR	POR	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743	1,062,743
ADA	48												
ADA	49	Total POR	POR	0.00000	0.04173	0.00841	0.00000	0.09875	0.02628	0.05428	0.11092	0.01139	0.01096
ADA	50												
ADA	1	**ALLOCATED DIRECT ASSIGNMENTS**											
ADA	2	**DIRECT ASSIGN TO CLASSES W/SALES REV FUNCTIONS**											
ADA	3												
ADA	4	**AVAILABLE**											
ADA	5	Residential	SREVRES	0	0	0	0	0	0	0	0	0	0
ADA	6	Residential Heating	SREVRH	0	0	0	0	0	0	0	0	0	0
ADA	7	General Service	SREVGS	0	0	0	0	0	0	0	0	0	0
ADA	8	Primary Distribution	SREVPRID	0	0	0	0	0	0	0	0	0	0
ADA	9	High Tension	SREVHT	0	0	0	0	0	0	0	0	0	0
ADA	10	Electric Propulsion	SREVEP	0	0	0	0	0	0	0	0	0	0
ADA	11	Lighting	SREVLCUST	0	0	0	0	0	0	0	0	0	0
ADA	12												
ADA	13												
ADA	14												
ADA	15	Total Available	SREVAVAIL	0	0	0	0	0	0	0	0	0	0
ADA	16												
ADA	17	Total Available	SREVAVAIL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ADA	18												
ADA	19												

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
ADA	20											
ADA	21											
ADA	22											
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ADA	47											
ADA	48											
ADA	49											
ADA	50											
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**										
RRW	2											
RRW	3	PRESENT RATES										
RRW	4	--										
RRW	5	RATE BASE		4,820,415	3,352,510	1,059	1,466,847	0	6,048	3,346,461	2,273,254	707,349
RRW	6	NET OPER INC (PRESENT RATES)		277,780	194,072	61	83,646	0	349	193,723	131,883	40,781
RRW	7	RATE OF RETURN (PRES RATES)		5.76%	5.79%	5.79%	5.70%	149.77%	5.77%	5.79%	5.80%	5.77%
RRW	8	RELATIVE RATE OF RETURN		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
RRW	9	SALES REVENUE (PRE RATES)		1,224,574	701,345	8,997	514,232	0	1,809	699,536	486,428	159,403
RRW	10	REVENUE PRES RATES $/KWH		$0.0327	$0.0187	$0.0002	$0.0137	$0.0000	$0.0000	$0.0187	$0.0130	$0.0043
RRW	11	REVENUE REQUIRED - $/MO/CUST		$61.66	$35.31	$0.45	$25.89	$0.00	$0.09	$35.22	$24.49	$8.03
RRW	12	SALES REV REQUIRED $/KW		$19.41	$11.11	$0.14	$8.15	$0.00	$0.03	$11.09	$7.71	$2.53
RRW	13											
RRW	14	CLAIMED RATE OF RETURN										
RRW	15	--										
RRW	16	CLAIMED RATE OF RETURN		7.79%	7.79%	7.79%	7.79%	46.83%	7.79%	7.79%	7.79%	7.79%
RRW	17	RETURN REQ FOR CLAIMED ROR		375,309	261,020	82	114,206	0	471	260,549	176,991	55,073
RRW	18	SALES REVENUE REQ CLAIMED ROR - Distribution		1,371,557	802,251	9,007	560,299	0	1,976	800,274	554,427	180,948

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	DEMDISSEC	DEMDISTRAN	ENEPPOTH	CUSDISPRI	CUSDISSEC	SERVICES	METERS	CUSTACCT	CUSTSERV	CUSTOTH
		(a)	(b)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)
ADA	20												
ADA	21												
ADA	22												
ADA	23												
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ADA	25												
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ADA	43												
ADA	44												
ADA	45												
ADA	46												
ADA	47												
ADA	48												
ADA	49												
ADA	50												
RRW	1	**DISTRIBUTION REVENUE REQUIREMENTS**											
RRW	2												
RRW	3	PRESENT RATES											
RRW	4	---											
RRW	5	RATE BASE		0	365,858	1,059	0	793,222	213,924	234,182	201,452	11,903	12,164
RRW	6	NET OPER INC (PRESENT RATES)		0	21,059	61	0	44,834	12,631	13,286	11,352	663	881
RRW	7	RATE OF RETURN (PRES RATES)		148.92%	5.76%	5.79%	149.16%	5.65%	5.90%	5.67%	5.64%	5.57%	7.24%
RRW	8	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	9	SALES REVENUE (PRE RATES)		0	53,705	8,997	0	174,862	31,326	83,991	178,249	19,241	26,563
RRW	10	REVENUE PRES RATES $/KWH		$0.0000	$0.0014	$0.0002	$0.0000	$0.0047	$0.0008	$0.0022	$0.0048	$0.0005	$0.0007
RRW	11	REVENUE REQUIRED - $/MO/CUST		$0.00	$2.70	$0.45	$0.00	$8.80	$1.58	$4.23	$8.97	$0.97	$1.34
RRW	12	SALES REV REQUIRED $/KW		$0.00	$0.85	$0.14	$0.00	$2.77	$0.50	$1.33	$2.82	$0.30	$0.42
RRW	13												
RRW	14	CLAIMED RATE OF RETURN											
RRW	15	---											
RRW	16	CLAIMED RATE OF RETURN		46.82%	7.79%	7.79%	46.82%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
RRW	17	RETURN REQ FOR CLAIMED ROR		0	28,485	82	0	61,759	16,656	18,233	15,685	927	947
RRW	18	SALES REVENUE REQ CLAIMED ROR - Distribution		0	64,900	9,007	0	200,376	37,394	91,449	184,780	19,638	26,663

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	TOTAL ELECTRIC DIVISION (c)	DEMAND (d)	ENERGY (e)	CUSTOMER (f)	PRODUCTION (g)	TRANSMISSION (h)	DISTRIBUTION (i)	DEMDISPHT (j)	DEMDISPRI (k)
RRW	19	REVENUE DEFICIENCY SALES REV		146,983	100,906	10	46,067	0	167	100,738	67,999	21,545
RRW	20	PERCENT INCREASE REQUIRED		12.00%	14.39%	0.12%	8.96%	27.01%	9.25%	14.40%	13.98%	13.52%
RRW	21	ANNUAL BOOKED KWH SALES		37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876
RRW	22	SALES REV REQUIRED $/KWH		$0.0366	$0.0214	$0.0002	$0.0150	$0.0000	$0.0001	$0.0214	$0.0148	$0.0048
RRW	23	REVENUE DEFICIENCY $/KWH		$0.0039	$0.0027	$0.0000	$0.0012	$0.0000	$0.0000	$0.0027	$0.0018	$0.0006

PECO Energy Company
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For Future Test Year Ended December 31, 2019

SCH NO.	LINE NO.	DESCRIPTION (a)	ALLOCATION BASIS (b)	DEMDISSEC (l)	DEMDISTRAN (m)	ENEPPOTH (n)	CUSDISPRI (o)	CUSDISSEC (p)	SERVICES (r)	METERS (s)	CUSTACCT (t)	CUSTSERV (u)	CUSTOTH (v)
RRW	19	REVENUE DEFICIENCY SALES REV		0	11,195	10	0	25,514	6,068	7,458	6,531	397	100
RRW	20	PERCENT INCREASE REQUIRED		27.75%	20.85%	0.12%	27.61%	14.59%	19.37%	8.88%	3.66%	2.07%	0.38%
RRW	21	ANNUAL BOOKED KWH SALES		37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876	37,430,876
RRW	22	SALES REV REQUIRED $/KWH		$0.0000	$0.0017	$0.0002	$0.0000	$0.0054	$0.0010	$0.0024	$0.0049	$0.0005	$0.0007
RRW	23	REVENUE DEFICIENCY $/KWH		$0.0000	$0.0003	$0.0000	$0.0000	$0.0007	$0.0002	$0.0002	$0.0002	$0.0000	$0.0000

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For Future Test Year Ended December 31, 2019

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										
3	**RATE OF RETURN**		5.76%	5.65%	4.50%	6.63%	6.46%	6.03%	3.65%	7.12%
4										
5	**REVENUES REQUIRED**									
6	**DEMAND COMPONENTS**	701,345	701,345	298,201	82,529	167,584	6,499	134,228	7,039	5,265
7	DEMAND PRODUCTION COMPONENT		0	0	0	0	0	0	0	0
8	DEMAND TRANSMISSION COMPONENT		1,809	843	207	383	11	348	15	1
9	DEMAND DISTRIBUTION COMPONENT	699,536	699,536	297,358	82,322	167,200	6,487	133,880	7,024	5,264
10	DEMAND DISTRIBUTION PRIMARY HT		486,428	183,734	51,015	103,091	4,442	133,880	7,024	3,243
11	DEMAND DISTRIBUTION PRIMARY		159,403	84,795	23,642	47,431	2,045	0	0	1,490
12	DEMAND DISTRIBUTION SECONDARY		0	0	0	0	0	0	0	0
13	DEMAND DISTRIBUTION TRANSFORMERS		53,705	28,829	7,665	16,678	0	0	0	532
14	**ENERGY COMPONENTS**	8,997	8,997	4,262	1,118	1,576	51	1,893	69	28
15	ENERGY PUR PWR & OTHER		8,997	4,262	1,118	1,576	51	1,893	69	28
16	**CUSTOMER COMPONENTS**	514,232	514,232	378,612	52,788	55,691	1,628	10,632	98	14,782
17	CUSTOMER DISTRIBUTION PRIMARY		0	0	0	0	0	0	0	0
18	CUSTOMER DISTRIBUTION SECONDARY		174,862	134,744	17,925	16,530	0	0	0	5,664
19	AVAILABLE COMPONENT		0	0	0	0	0	0	0	0
20	CUSTOMER SERVICES INVESTMENT		31,326	17,149	2,174	11,775	34	193	0	0
21	CUSTOMER METER INVESTMENT		83,991	61,387	8,442	11,853	335	1,950	25	0
22	CUSTOMER ACCOUNTS		178,249	133,389	19,674	15,099	1,237	7,696	32	1,124
23	CUSTOMER SERVICES		19,241	15,094	2,247	789	29	1,010	41	31
24	CUSTOMER OTHER		26,563	16,851	2,327	(354)	(7)	(217)	0	7,963
25	**TOTAL COMPANY**	1,224,574	1,224,574	681,075	136,434	224,851	8,178	146,754	7,207	20,075
26										
27										
28										
29										
30	Annual MWh Sales @ Meter		37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
31	Annual MW - Billed		63,105	0	0	26,760	1,043	33,557	1,746	0
32	Number of Customer Bills		19,860,923	15,606,895	2,247,564	1,821,211	5,400	31,932	465	147,456
33										
34	Use per Month per Customer		1.88	0.67	1.21	4.43	75.10	466.22	1,345.45	1.38
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

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										
3	**RATE OF RETURN**		5.76%	5.65%	4.50%	6.63%	6.46%	6.03%	3.65%	7.12%
4										
5	**$/KWH**									
6	**DEMAND COMPONENTS**	$0.0187	$0.0187	$0.0283	$0.0303	$0.0208	$0.0160	$0.0090	$0.0113	$0.0259
7	DEMAND PRODUCTION COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	DEMAND TRANSMISSION COMPONENT		$0.0000	$0.0001	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
9	DEMAND DISTRIBUTION COMPONENT		$0.0187	$0.0283	$0.0303	$0.0207	$0.0160	$0.0090	$0.0112	$0.0259
10	DEMAND DISTRIBUTION PRIMARY HT		$0.0130	$0.0175	$0.0187	$0.0128	$0.0110	$0.0090	$0.0112	$0.0159
11	DEMAND DISTRIBUTION PRIMARY		$0.0043	$0.0081	$0.0087	$0.0059	$0.0050	$0.0000	$0.0000	$0.0073
12	DEMAND DISTRIBUTION SECONDARY		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
14	DEMAND DISTRIBUTION TRANSFORMERS		$0.0014	$0.0027	$0.0028	$0.0021	$0.0000	$0.0000	$0.0000	$0.0026
13	**ENERGY COMPONENTS**	$0.0002	$0.0002	$0.0004	$0.0004	$0.0002	$0.0001	$0.0001	$0.0001	$0.0001
15	ENERGY PUR PWR & OTHER		$0.0002	$0.0004	$0.0004	$0.0002	$0.0001	$0.0001	$0.0001	$0.0001
16	**CUSTOMER COMPONENTS**	$0.0137	$0.0137	$0.0360	$0.0194	$0.0069	$0.0040	$0.0007	$0.0002	$0.0726
17	CUSTOMER DISTRIBUTION PRIMARY		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
18	CUSTOMER DISTRIBUTION SECONDARY		$0.0047	$0.0128	$0.0066	$0.0020	$0.0000	$0.0000	$0.0000	$0.0278
19	AVAILABLE COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
20	CUSTOMER SERVICES INVESTMENT		$0.0008	$0.0016	$0.0008	$0.0015	$0.0001	$0.0000	$0.0000	$0.0000
21	CUSTOMER METER INVESTMENT		$0.0022	$0.0058	$0.0031	$0.0015	$0.0008	$0.0001	$0.0000	$0.0000
22	CUSTOMER ACCOUNTS		$0.0048	$0.0127	$0.0072	$0.0019	$0.0031	$0.0005	$0.0001	$0.0055
23	CUSTOMER SERVICES		$0.0005	$0.0014	$0.0008	$0.0001	$0.0001	$0.0001	$0.0001	$0.0002
24	CUSTOMER OTHER		$0.0007	$0.0016	$0.0009	($0.0000)	($0.0000)	($0.0000)	$0.0000	$0.0391
25	**TOTAL COMPANY**	$0.0327	$0.0327	$0.0647	$0.0501	$0.0279	$0.0202	$0.0099	$0.0115	$0.0986
26										
27	**$/KW**									
28	**DEMAND COMPONENTS**	$11.11	$11.11	$0.00	$0.00	$6.26	$6.23	$4.00	$4.03	$0.00
29	DEMAND PRODUCTION COMPONENT		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	DEMAND TRANSMISSION COMPONENT		$0.03	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.00
31	DEMAND DISTRIBUTION COMPONENT		$11.09	$0.00	$0.00	$6.25	$6.22	$3.99	$4.02	$0.00
32	DEMAND DISTRIBUTION PRIMARY HT		$7.71	$0.00	$0.00	$3.85	$4.26	$3.99	$4.02	$0.00
33	DEMAND DISTRIBUTION PRIMARY		$2.53	$0.00	$0.00	$1.77	$1.96	$0.00	$0.00	$0.00
34	DEMAND DISTRIBUTION SECONDARY		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
35										
36	**$/MONTH/CUSTOMER**									
37	**CUSTOMER COMPONENTS**	$25.89	$25.89	$24.26	$23.49	$30.58	$301.48	$332.96	$211.80	$100.25
38	CUSTOMER DISTRIBUTION PRIMARY		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
39	CUSTOMER DISTRIBUTION SECONDARY		$8.80	$8.63	$7.98	$9.08	$0.00	$0.00	$0.00	$38.41
40	AVAILABLE COMPONENT		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
41	CUSTOMER SERVICES INVESTMENT		$1.58	$1.10	$0.97	$6.47	$6.31	$6.06	$0.00	$0.00
42	CUSTOMER METER INVESTMENT		$4.23	$3.93	$3.76	$6.51	$61.95	$61.08	$54.41	$0.00
43	CUSTOMER ACCOUNTS		$8.97	$8.55	$8.75	$8.29	$229.07	$241.00	$68.33	$7.62
44	CUSTOMER SERVICES		$0.97	$0.97	$1.00	$0.43	$5.41	$31.63	$88.00	$0.21
45	CUSTOMER OTHER		$1.34	$1.08	$1.04	($0.19)	($1.26)	($6.81)	$1.06	$54.01
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

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	**CLAIMED RATE OF RETURN SUMMARY SCHEDULE - REVENUE REQUIREMENTS**									
2										
3	**RATE OF RETURN**		7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
4										
5	**REVENUES REQUIRED**									
6	**DEMAND COMPONENTS**	802,251	802,251	344,384	103,895	181,046	7,080	150,864	9,481	5,500
7	DEMAND PRODUCTION COMPONENT		0	0	0	0	0	0	0	0
8	DEMAND TRANSMISSION COMPONENT		1,976	926	241	402	12	377	18	1
9	DEMAND DISTRIBUTION COMPONENT		800,274	343,458	103,655	180,645	7,068	150,487	9,463	5,499
10	DEMAND DISTRIBUTION PRIMARY HT		554,427	211,325	63,783	111,139	4,845	150,487	9,463	3,383
11	DEMAND DISTRIBUTION PRIMARY		180,948	96,938	29,262	50,975	2,222	0	0	1,552
12	DEMAND DISTRIBUTION SECONDARY		0	0	0	0	0	0	0	0
14	DEMAND DISTRIBUTION TRANSFORMERS		64,900	35,195	10,610	18,531	0	0	0	564
13	**ENERGY COMPONENTS**	9,007	9,007	4,263	1,120	1,576	51	1,899	69	28
15	ENERGY PUR PWR & OTHER		9,007	4,263	1,120	1,576	51	1,899	69	28
16	**CUSTOMER COMPONENTS**	560,299	560,299	413,047	60,388	58,743	1,678	11,006	108	15,330
17	CUSTOMER DISTRIBUTION PRIMARY		0	0	0	0	0	0	0	0
18	CUSTOMER DISTRIBUTION SECONDARY		200,376	154,412	22,275	17,787	0	0	0	5,903
19	AVAILABLE COMPONENT		0	0	0	0	0	0	0	0
20	CUSTOMER SERVICES INVESTMENT		37,394	20,999	3,025	13,103	39	229	0	0
21	CUSTOMER METER INVESTMENT		91,449	66,886	9,659	12,423	353	2,097	30	0
22	CUSTOMER ACCOUNTS		184,780	138,204	20,788	15,404	1,266	7,947	34	1,136
23	CUSTOMER SERVICES		19,638	15,392	2,316	797	30	1,030	43	31
24	CUSTOMER OTHER		26,663	17,154	2,325	(770)	(10)	(297)	1	8,260
25	**TOTAL COMPANY**	1,371,557	1,371,557	761,694	165,404	241,366	8,809	163,769	9,658	20,858
26										
27										0
28										
29										
30	Annual MWh Sales @ Meter		37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
31	Annual MW - Billed		63,105	0	0	26,760	1,043	33,557	1,746	0
32	Number of Customer Bills		19,860,923	15,606,895	2,247,564	1,821,211	5,400	31,932	465	147,456
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PECO Energy Company
Electric Class Cost of Service Study ($000)
For Future Test Year Ended December 31, 2019

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	**CLAIMED RATE OF RETURN SUMMARY SCHEDULE - UNIT COSTS**									
2										
3	**RATE OF RETURN**		7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%	7.79%
4										
5	**$/KWH**									
6	**DEMAND COMPONENTS**	$0.0214	$0.0214	$0.0327	$0.0382	$0.0224	$0.0175	$0.0101	$0.0152	$0.0270
7	DEMAND PRODUCTION COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	DEMAND TRANSMISSION COMPONENT		$0.0001	$0.0001	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
9	DEMAND DISTRIBUTION COMPONENT		$0.0214	$0.0327	$0.0381	$0.0224	$0.0174	$0.0101	$0.0151	$0.0270
10	DEMAND DISTRIBUTION PRIMARY HT		$0.0148	$0.0201	$0.0234	$0.0138	$0.0119	$0.0101	$0.0151	$0.0166
11	DEMAND DISTRIBUTION PRIMARY		$0.0048	$0.0092	$0.0108	$0.0063	$0.0055	$0.0000	$0.0000	$0.0076
12	DEMAND DISTRIBUTION SECONDARY		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
14	DEMAND DISTRIBUTION TRANSFORMERS		$0.0017	$0.0033	$0.0039	$0.0023	$0.0000	$0.0000	$0.0000	$0.0028
13	**ENERGY COMPONENTS**	$0.0002	$0.0002	$0.0004	$0.0004	$0.0002	$0.0001	$0.0001	$0.0001	$0.0001
15	ENERGY PUR PWR & OTHER		$0.0002	$0.0004	$0.0004	$0.0002	$0.0001	$0.0001	$0.0001	$0.0001
16	**CUSTOMER COMPONENTS**	$0.0150	$0.0150	$0.0393	$0.0222	$0.0073	$0.0041	$0.0007	$0.0002	$0.0753
17	CUSTOMER DISTRIBUTION PRIMARY		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
18	CUSTOMER DISTRIBUTION SECONDARY		$0.0054	$0.0147	$0.0082	$0.0022	$0.0000	$0.0000	$0.0000	$0.0290
19	AVAILABLE COMPONENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
20	CUSTOMER SERVICES INVESTMENT		$0.0010	$0.0020	$0.0011	$0.0016	$0.0001	$0.0000	$0.0000	$0.0000
21	CUSTOMER METER INVESTMENT		$0.0024	$0.0064	$0.0035	$0.0015	$0.0009	$0.0001	$0.0000	$0.0000
22	CUSTOMER ACCOUNTS		$0.0049	$0.0131	$0.0076	$0.0019	$0.0031	$0.0005	$0.0001	$0.0056
23	CUSTOMER SERVICES		$0.0005	$0.0015	$0.0009	$0.0001	$0.0001	$0.0001	$0.0001	$0.0002
24	CUSTOMER OTHER		$0.0007	$0.0016	$0.0009	($0.0001)	($0.0000)	($0.0000)	$0.0000	$0.0406
25	**TOTAL COMPANY**	$0.0366	$0.0366	$0.0724	$0.0608	$0.0299	$0.0217	$0.0110	$0.0154	$0.1025
26										
27	**$/KW**									
28	**DEMAND COMPONENTS**	$12.71	$12.71	$0.00	$0.00	$6.77	$6.79	$4.50	$5.43	$0.00
29	DEMAND PRODUCTION COMPONENT		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	DEMAND TRANSMISSION COMPONENT		$0.03	$0.00	$0.00	$0.02	$0.01	$0.01	$0.01	$0.00
31	DEMAND DISTRIBUTION COMPONENT		$12.68	$0.00	$0.00	$6.75	$6.78	$4.48	$5.42	$0.00
32	DEMAND DISTRIBUTION PRIMARY HT		$8.79	$0.00	$0.00	$4.15	$4.65	$4.48	$5.42	$0.00
33	DEMAND DISTRIBUTION PRIMARY		$2.87	$0.00	$0.00	$1.90	$2.13	$0.00	$0.00	$0.00
34	DEMAND DISTRIBUTION SECONDARY		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
35										
36	**$/MONTH/CUSTOMER**									
37	**CUSTOMER COMPONENTS**	$28.21	$28.21	$26.47	$26.87	$32.25	$310.77	$344.65	$231.30	$103.97
38	CUSTOMER DISTRIBUTION PRIMARY		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
39	CUSTOMER DISTRIBUTION SECONDARY		$10.09	$9.89	$9.91	$9.77	$0.00	$0.00	$0.00	$40.03
40	AVAILABLE COMPONENT		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
41	CUSTOMER SERVICES INVESTMENT		$1.88	$1.35	$1.35	$7.19	$7.14	$7.16	$0.00	$0.00
42	CUSTOMER METER INVESTMENT		$4.60	$4.29	$4.30	$6.82	$65.39	$65.68	$64.93	$0.00
43	CUSTOMER ACCOUNTS		$9.30	$8.86	$9.25	$8.46	$234.53	$248.87	$73.49	$7.71
44	CUSTOMER SERVICES		$0.99	$0.99	$1.03	$0.44	$5.48	$32.25	$91.72	$0.21
45	CUSTOMER OTHER		$1.34	$1.10	$1.03	($0.42)	($1.77)	($9.31)	$1.15	$56.02
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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)	$ 20,998	$ 3,025	$ 24,023	$ 13,102	$ 39	$ 229
2	Customer Meter Investment($000)	$ 66,886	$ 9,659	$ 76,545	$ 12,423	$ 353	$ 2,097
3	Customer Accounts($000)	$ 138,204	$ 20,788	$ 158,992	$ 15,404	$ 1,266	$ 7,947
4	Customer Services($000)	$ 15,392	$ 2,316	$ 17,708	$ 797	$ 30	$ 1,030
5	Total Revenue Requirement($000)	$ 241,480	$ 35,789	$ 277,268	$ 41,726	$ 1,688	$ 11,303
6	Number of Customer Bills	15,606,895	2,247,564	17,854,459	1,821,211	5,400	31,932
7	$/Month/Customer (Line 5/Line 6*1000)	$ 15.47	$ 15.92	$ 15.53	$ 22.91	$ 312.53	$ 353.96

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 20 to 23.

Night Service Rider

Line	Description	FERC Account	Lines @ PECO Exhibits JD-2 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	RBP25,26,35,36,39	$ 638,584	45%	$ 20,047	47%	$ 380,997	41%	$ 24,218	42%
2	Total Distribution Plant		RBP45	$ 1,409,010		$ 42,798		$ 925,789		$ 58,280	
3	NS Related Distribution O&M	593,594	E32, 33	$ 30,234	52%	$ 1,162	57%	$ 20,365	50%	$ 1,295	50%
4	Total Distribution Plant O&M Less A&G		E40	$ 57,709		$ 2,046		$ 40,940		$ 2,583	
5	Customer Accounts O&Ms	901-910,912,916	E59,67,69	$ 10,388		$ 595		$ 4,829		$ 43	
6	Total Dist. O&M + Customer Account			$ 68,097	44%	$ 2,641	44%	$ 45,769	44%	$ 2,626	49%
7	Total Distribution Revenue @ 7.79%		S69	$ 241,366		$ 8,809		$ 163,769		$ 9,658	
8	Total Distribution Operation Expense Less Depr Less Fed/State Taxes		S57,59,60	$ 115,484		$ 4,605		$ 79,715		$ 4,582	
9	NS Related Operation Expense			$ 51,273		$ 2,026		$ 35,469		$ 2,260	
10	Capital Related Costs @ 7.79%			$ 125,882		$ 4,204		$ 84,054		$ 5,076	
11	NS Related Capital Cost @ 7.79%			$ 57,051		$ 1,969		$ 34,591		$ 2,109	
12	NS Related Capital Plus Expense			$ 108,325		$ 3,995		$ 70,061		$ 4,369	
13	NCP Demand (MW)		AF21	1,889,922		83,086		2,569,692		163,341	
14	Monthly NS Cost ($/kW)			$ 4.78		$ 4.01		$ 2.27		$ 2.23	

PECO Energy Company (Electric)
Future Test Year 2019
Cost of Service Study

Table of External Allocators

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	37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
2	MWh	Energy @ Generation	40,298,768	11,603,239	3,001,645	8,900,776	439,648	15,478,422	650,472	224,566
3	MW	Demand Transmission (1CP)	8,141,078	3,547,555	512,386	1,546,608	72,427	2,356,885	99,550	5,668
4	MW	Demand Distribution Primary High Tension (NCP)	9,380,936	3,547,555	1,069,010	1,889,922	83,086	2,569,692	163,341	58,330
5	MW	Demand Distribution Primary (NCP)	6,647,903	3,547,555	1,069,010	1,889,922	83,086	-	-	58,330
6	MW	Demand Distribution Secondary (NCP)	6,564,817	3,547,555	1,069,010	1,889,922	-	-	-	58,330
7	KW	Billed Capacity	63,104,860	0	0	26,759,561	1,042,607	33,557,154	1,745,537	0
8	#	Bills	19,860,923	15,606,895	2,247,564	1,821,211	5,400	31,932	465	147,456
9	#	Customers	1,655,077	1,300,575	187,297	151,768	450	2,661	39	12,288
10	#	Customers-CI	3,111				450	2,661		
11	#	Customers-Res	1,487,872	1,300,575	187,297					
12	#	Location Secondary	1,690,712	1,300,575	187,297	151,768				51,073
13	$000	Services Cost	5,159,430	2,885,140	415,492	1,821,461	5,401	31,936	-	-
14	$000	Meters Cost	316,854	231,254	33,303	43,557	1,249	7,384	108	-
15	$000	Purchase Power	653,769	418,108	109,879	92,584	862	31,629	-	708
16	$000	Write-Offs	92,015	67,156	15,223	7,510	96	2,019	-	11
17	%	Customer Records and Collection Expenses (Acct903)	100.00%	74.36%	11.17%	8.39%	0.75%	4.68%	0.02%	0.62%
18	%	Miscellaneous Customer Accounts (Acct905)	100.00%	78.58%	11.32%	9.17%	0.03%	0.16%	0.00%	0.74%
19	%	Customer Assistant Expenses (Acct908)	100.00%	78.24%	11.78%	3.46%	0.17%	6.01%	0.25%	0.09%
20	%	Customer Service-Miscellaneous Expenses (Acct910)	100.00%	78.58%	11.32%	9.17%	0.03%	0.16%	0.00%	0.74%
21	%	AR Over60-Day	100.00%	75.04%	15.03%	6.20%	0.19%	3.37%	0.17%	0.00%
22	%	Customer Deposit	100.00%	33.42%	7.58%	52.73%	0.28%	5.98%	0.00%	0.00%
23	%	Purchase of Receivables	100.00%	31.75%	8.21%	31.68%	0.73%	26.96%	0.00%	0.66%
24	%	Lighting	100.00%							100%

PECO Energy Company (Electric)
Future Test Year 2019
Cost of Service Study

External Allocator Values by Function

Schedule-2

Line	Accounts	Total	Primary-HT	Primary	Secondary
1	Overhead Conductors & Devices (Acct 365)	100.00%	44.28%	27.89%	27.83%
2	Underground Conductors & Devices (Acct 367)	100.00%	58.03%	17.78%	24.19%
3					
4					

Conductors - Functional
As of December 31, 1999

Schedule-3

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 October 30, 2017

Line	System Voltage	Class	Overhead Conductor Wire_Miles	Underground Conductor Wire_Miles
1	2.4	Primary	134	247
2	4	Primary	11,264	3,522
3	13	HT	8,999	7,606
4	34	HT	9,098	4,695
5			29,495	16,070
6				
7		Primary	11,398	3,769
8		HT	18,097	12,301
9			29,495	16,070
10				
11		Primary	38.6%	23.5%
12		HT	61.4%	76.5%
13			100.0%	100.0%
14				

Service Costs

Schedule-5

Line	Rate Class	Customer Numbers	Average Services Cost	Total Services Cost	Ratio
1	Residential	1,300,575	$ 2,218	$2,885,140,088	55.9%
2	Residential Heating	187,297	$ 2,218	415,491,809	8.1%
3	General Service	151,768	$ 12,002	1,821,461,121	35.3%
4	Primary Distribution	450	$ 12,002	5,400,742	0.1%
5	High Tension	2,661	$ 12,002	31,936,385	0.6%
6	Electric Propulsion	39			
7	Lighting	12,288			
8		1,655,077		$ 5,159,430,145	100%

	Residential Average Cost	Commercial Average Cost
2014	$ 2,243	$ 13,004
2015	2,241	11,914
2016	2,255	12,985
September 2017 YTD	2,125	9,840
Weighted Average	$ 2,218	$ 12,002

Meter Costs

Schedule-6

Book Value as of December 31, 2019

Line	Rate Class		Meter Costs
1	Residential	$	231,254,491
2	Residential Heating	$	33,303,182
3	General Service	$	43,556,579
4	Primary Distribution	$	1,248,654
5	High Tension	$	7,383,709
6	Electric Propulsion	$	107,523
7	Lighting		
8		$	316,854,139

PECO Energy Company (Electric)
Future Test Year 2019
Cost of Service Study

Customer Deposits

Schedule-7

Thirteen Months Ended December 31, 2017

Line	Activity	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Customer Deposit	100.0%	33.4%	7.6%	52.7%	0.3%	6.0%	0.0%	
2		100.0%	33.4%	7.6%	52.7%	0.3%	6.0%	0.0%	0.0%

PECO Energy Company (Electric)
Future Test Year 2019
Cost of Service Study

Customer Records and Collection Expenses (Account 903)
For Year 2016

Schedule-8

Line	Activity	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Billing	Bills	11,410,051	8,966,122.50	1,291,220	1,046,281	3,102	18,345	267	84,713
2	CAP Rates	Customers-Res	8,213	7,179	1,034	-	-	-	-	-
3	Recoveries	AR Over60-Day	4,390,612	3,294,598	659,980	272,401	8,254	148,107	7,273	-
4	Call Center	Customers	14,783,607	11,617,093	1,672,989	1,355,630	4,020	23,769	346	109,760
5	C&MS	Customers	7,237,319	5,687,152	819,012	663,649	1,968	11,636	169	53,733
6	ESO Activities	Customers-CI	1,940,691	-	-	-	280,717	1,659,974	-	-
7			39,770,493	29,572,144	4,444,235	3,337,961	298,060	1,861,830	8,056	248,206
8	**Acct903 Allocator**		**100.00%**	**74.36%**	**11.17%**	**8.39%**	**0.75%**	**4.68%**	**0.02%**	**0.62%**

Customer Assistance Expenses (Account 908)

Schedule-9

For Year 2016

Line	Activity	Allocator	Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Residential Marketing	Customers-Res	20,511	17,929.20	2,582	-	-	-	-	-
2	Conservation	Energy @ Generation	58,885	16,955	4,386	13,006	642	22,617	950	328
3	Marketing- General	Energy @ Generation	1,125,447	324,050	83,829	248,577	12,278	432,275	18,166	6,272
4	LIURP	Customers-Res	6,361,008	5,560,269	800,740	-	-	-	-	-
5			7,565,851	5,919,203	891,536	261,583	12,921	454,892	19,117	6,600
6	**Acct908 Allocator**		**100.00%**	**78.24%**	**11.78%**	**3.46%**	**0.17%**	**6.01%**	**0.25%**	**0.09%**

Write-Offs

Schedule-10 **Net Write-Offs from 2015 to 2017**

Line	Rate Class	Net Write-Offs
1	Residential	$ 67,155,611
2	Residential Heating	15,223,148
3	General Service	7,510,106
4	Primary Distribution	95,948
5	High Tension	2,018,968
6	Electric Propulsion	-
7	Lighting	11,428
8		$ 92,015,208

Schedule-11

Accounts Receivable Over 60-Day

July 2016 to June 2017

	Rate Class	Average Over 60-Day	Over 60-Day Allocator	Residential	% Residential Revenue	LC&I Revenue	% LC&I Revenue
1	Residential	$ 45,941,491	75.0%	$ 681,075,237	83.3%		
2	Residential Heating	9,203,087	15.0%	136,434,289	16.7%		
3	General Service	3,798,492	6.2%				
4	Primary Distribution	115,091	0.2%			$ 8,178,120	5.0%
5	High Tension	2,065,275	3.4%			146,754,032	90.5%
6	Electric Propulsion	101,418	0.2%			7,206,544	4.4%
7	Lighting	0	0.0%				
8	**Total**	$ 61,224,853	100.0%	$ 817,509,526	100.0%	$162,138,697	100.0%

Purchase of Receivables
For Test Year 2019

Schedule-12

Line		Total	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	Sales (MWh)	37,430,876	10,518,755	2,721,100	8,068,875	405,542	14,887,392	625,635	203,577
2	% R and RH		79.4%	20.6%					
3	% PD and HT					2.7%	97.3%		
4	Total Amount ($)	$1,062,743,421	337,426,698	87,289,014	336,728,039	7,804,643	286,507,544	-	6,987,483
	POR Allocator	**100%**	**31.75%**	**8.21%**	**31.68%**	**0.73%**	**26.96%**	**0.00%**	**0.66%**

PECO Energy Company (Electric)
Future Test Year 2019
Cost of Service Study

Demand Allocator

Schedule-13

October 2016 to September 2017

Line	Demand Allocator	Total MWs	Residential	Residential Heating	General Service	Primary Distribution	High Tension	Electric Propulsion	Lighting
1	1CP	8,141,078	3,547,555	512,386	1,546,608	72,427	2,356,885	99,550	5,668
2	NCP- Primary HT	9,380,936	3,547,555	1,069,010	1,889,922	83,086	2,569,692	163,341	58,330
3	NCP- Primary	6,647,903	3,547,555	1,069,010	1,889,922	83,086	-	-	58,330
4	NCP- Secondary	6,564,817	3,547,555	1,069,010	1,889,922	-	-	-	58,330
5									

Energy Allocator
For Test Year 2019

Schedule-14

Line	Rate Class	Function	MWh Deliveries at Meter	MWh Deliveries at Generation
1	Residential	Secondary	10,518,755	11,603,239
2	Residential Heating	Secondary	2,721,100	3,001,645
3	General Service	Secondary	8,068,875	8,900,776
4	Primary Distribution	Primary	405,542	439,648
5	High Tension	HT	14,887,392	15,478,422
6	Electric Propulsion	HT	625,635	650,472
7	Lighting	Secondary	203,577	224,566
8	**Total**		37,430,876	40,298,768

PECO Energy Company
Estimated Cash Working Capital Rate for the GSA
To be Effective January 1, 2019
($1000)

1	CWC Rate Base Allocated to Purchased Power(1)	$	19,631
2	Rate of Return(2)		7.786%
3	Return on CWC Rate Base	$	1,528
4	Income Taxes on Equity portion of Return(3)	$	466
5	Gross Receipts Tax @ 5.9%	$	125

6	Total Revenue Requirement	$	2,120
7	Default Service Sales (MWH)		10,946,572
8	Estimated Rate per kWh	$	0.00019

Notes:
1 PECO Exhibit JD-1, Line 34
2 PECO Exhibit BSY-1, Schedule 1
3 PECO Exhibit JD-1, Line 80

PECO Energy Company
Estimated Cash Working Capital Rate for the TSC
To be Effective January 1, 2019
($1000)

1	CWC Rate Base Allocated to Transmission TSC [1]	$	6,141
2	Rate of Return[2]		7.79%
3	Return on CWC Rate Base	$	478
4	Income Taxes on Equity portion of Return[3]	$	146
5	Gross Receipts Tax @ 5.9%	$	39

6	Total Revenue Requirement	$	663
7	Default Service Peak Forecast (MW)		3,002
8	Estimated Rate per MW-year	$	221

Notes:
1 PECO Exhibit JD-1, Line 43
2 PECO Exhibit BSY-1, Schedule 1
3 PECO Exhibit JD-1, Line 92

High Tension Power Station Equipment Related Costs

Line	Description	FERC Account	Lines @ PECO Exhibits JD-1 and JD-2	HT Amount	Ratio
1	HT Station Equipment	362	RBP 18	$ 318,614	34%
2	Total Distribution Plant		RBP45	$ 925,789	
3	HT Station Equipment Related O&M	582,592	E18, E31	$ 6,273	
4	Total Distribution Plant O&M Less A&G		E40	$ 40,940	
5	Customer Accounts O&Ms	901-910,912,916	E59,67,69	$ 4,829	
6	Total Dist. O&M + Customer Account for HT			$ 45,769	14%
7	Total Distribution Revenue @ 7.79%		S69	$ 163,769	
8	Total Distribution Operation Expense Less Depr Less Fed/State Taxes		S57,59,60	$ 79,715	
9	Station Equipment Related Expense			$ 10,926	
10	Capital Related Costs @ 7.79%			$ 84,054	
11	Station Equipment Related Capital Costs @ 7.79%			$ 28,927	
12	Station Equipment Capital Plus Expense			$ 39,853	
13	HT NCP Demand (MW)		AF21	2,569,692	
14	Monthly HT Cost ($/kW)			$ 1.29	

PECO ENERGY COMPANY
STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – ELECTRIC DIVISION

DOCKET NO. R-2018-3000164

DIRECT TESTIMONY

WITNESS: MARK KEHL

SUBJECT: REVENUE ALLOCATION; RATE DESIGN; AND PROOF OF REVENUES

DATED: MARCH 29, 2018

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DIRECT TESTIMONY
OF
MARK KEHL

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Mark Kehl. 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 Principal Regulatory and Rates Specialist. In that capacity, I am responsible for issues regarding tariff administration, financial analysis, project management and regulatory affairs for electric and gas activities throughout PECO's operations and service territory.

3. Q. Please describe your educational background.

A. I received a Bachelor of Science in Accounting from DeSales University and Master of Business Administration from Lehigh University.

4. Q. Please describe your professional experience.

A. I began working for PECO in April of 2009 as a Senior Business Analyst primarily focused on forecasting Accounts Receivable, Write-offs and Bad Debt expense. In March of 2011, I was promoted to my current position within Regulatory Policy and Strategy. Prior to working at PECO, I was a financial analyst at Merrill Lynch.

5. Q. What is the purpose of your testimony?

A. The purpose of my testimony is three-fold. First, I will describe how PECO proposes to allocate its claimed revenue increase among rate classes. In so doing, I will explain the principles that guided PECO in developing its proposed revenue allocation. Second, I will identify the changes PECO is proposing in the rate design for certain rate classes, explain why PECO is proposing those changes and describe how the proposed new rates were developed. As part of that discussion, I will also describe changes to existing rates and riders that PECO is proposing. Finally, I will discuss PECO's proposal to recover a portion of the costs related to the Company's transition from a tiered-discount to a Fixed Credit Option ("FCO") Customer Assistance Program ("CAP").

6. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following PECO Exhibits:

Exhibit MK-1	Proposed Revenue Allocation, Proposed Increases by Class and Class Rates of Return and Relative Rates of Return under Proposed Rates
Exhibit MK-2	Relevant Tariff Pages (Blacklined to Show Changes)
Exhibit MK-3	Comparison of Residential Customer Charges for Pennsylvania Electric Utilities
Exhibit MK-4	Detail of the Universal Service Fund Charge Adjustment Calculation
Exhibit MK-5	Summary of Revenue at Present and Proposed Rates
Exhibit MK-6	Proof of Revenues at Present and Proposed Rates

II. REVENUE ALLOCATION

7. 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:

a. The results of the class cost of service study ("COS Study"), prepared by Ms. Jiang Ding and discussed in PECO Statement No. 6, should be used as a guide in allocating the proposed revenue increase among rate classes;

b. The proposed revenue allocation should move all rate classes closer to the cost of service indicated by the COS Study; and

c. Customer impacts should be considered, and PECO should attempt to avoid increases in revenue for major rate classes that, on a percentage basis, are disproportionate relative to the system average increase.

8. 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, which was prepared by Ms. Ding and accompanies her direct testimony (PECO Statement No. 6). PECO Exhibit JD-1 shows, at page 1, line 25, the overall and class rates of return produced by the Company's current electric distribution base rates based on its supporting data for the twelve months ending December 31, 2019, which is the Fully Projected Future Test Year ("FPFTY") in this case. PECO Exhibit JD-1 shows, at page 2, line 70, the increase or decrease (in dollars and as a percentage of class electric distribution revenues under current rates) that each rate class would have to receive in order 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 COS Study are an important guide in evaluating its proposed revenue allocation, they are not the only factor that must be considered.

9. Q. What is the revenue allocation that PECO determined to be appropriate in this case?

A. The proposed revenue allocation is shown in PECO Exhibit MK-1. In order to allow for a comparison of underlying system allocations on an "apples-to-apples" basis with prior base rate cases, PECO Exhibit MK-1 first develops the system allocation that would be used in the absence of the 2019 effects of the Tax Cuts and Jobs Act ("TCJA"). It begins by showing: (1) the allocation of approximately $147 million electric distribution revenue that would be required on a system-wide basis absent the 2019 TCJA effects, plus the addition of Distribution System Improvement Charge ("DSIC") revenue above 2018 levels, for each rate class; (2) an adjustment to reach an approximately $143 million revenue increase based on the decreases in class distribution revenue under the Transmission Service Charge and Generation Supply Adjustment described by Ms. Ding in PECO Statement No. 6; (3) the proposed revenue increase as a percent of distribution revenues at current rates for each rate class; and (4) class rates of return and relative rates of return at present and proposed rates. Up to this point, PECO Exhibit MK-1 reflects the analysis that was used in prior base rate proceedings. PECO Exhibit MK-1 then shows the budgeted allocation of tax benefits to each rate class, including the net of the typical system-wide allocation, the effects of the return of 2019 TCJA tax benefits to customers, DSIC revenue and other adjustments that result in the $82 million revenue requirement increase over current levels being sought in this case, with that requested revenue increase allocated across each of the rate classes.

10. Q. Why is the proposed revenue allocation reasonable?

A. The proposed revenue allocation is reasonable because PECO Exhibit MK-1 shows that removing the effects of the tax benefits that will be returned to customers, DSIC revenue and other adjustments, and using the Company's COS Study as a guide, the proposed rates have been developed to make meaningful movement toward each class' cost of service, as evidenced by the relative rates of return shown on PECO Exhibit MK-1, while also mitigating the impact of the revenue increase on each major rate class.

11. Q. Please explain the significance of the relative rates of return shown in PECO Exhibit MK-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. 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.

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 revenue increase or decrease allocated to that rate class, subject to certain rate design changes, discussed below. PECO Exhibit MK-2 is a copy of the Company's Tariff Electric-Pa. P. U.C. No. 6 ("Tariff No. 6") 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 Richard A. Schlesinger in PECO Statement No. 8. Tariff No. 6 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. 5 ("Tariff No. 5") and associated supplements. It is anticipated that Tariff No. 6, which was filed 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. 5 during the period Tariff No. 6 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. 6 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. Is PECO proposing to increase each class' fixed distribution service charge by the same percentage as the average increase for the class?

A. No, it is not. As shown on PECO Exhibits MK-1 and MK-3, PECO is proposing to increase residential fixed distribution charges by a greater percentage than the proposed overall revenue increase for the class in order to reduce the disparity between its current fixed distribution service charge and the customer-related costs that properly should be recovered by that charge. PECO is proposing that the fixed distribution service charges for other classes should be increased in the same manner to better align with customer-related costs.

14. Q. Why is it important to increase fixed distribution service charges so that they will be closer to the customer-classified costs?

A. Customer-classified costs are, by definition, costs that vary in relation to the number of customers, not usage or demand. Such costs include, principally, but not exclusively, the cost of meters, customer service lines, billing and meter reading. As a consequence, 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 fixed distribution service 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 changes because to do so would make the recovery of customer-related costs a function of customers' electric demand and/or usage, which they are not.

Misplacing customer costs in variable distribution charges has three adverse consequences. First, it can create inappropriate intra-class subsidies, because some customers will pay more than their share of the customer-classified costs and others less, based on their relative levels of demand or usage each month. Second, because customer costs, which are a fixed amount per customer, would be recovered in a charge that applies to demand or usage, which varies, the Company could recover either too little or too much of its customer-related costs as a consequence of variations in customer demand or usage. Finally, with advances in new technologies increasing the potential for customer bypass, it is more important than ever that the appropriate levels of fixed costs are recovered through fixed charges to avoid intra-class subsidies.

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.

III. RESIDENTIAL RATE CHANGES

15. Q. What residential rate change is PECO proposing?

A. PECO is proposing a residential fixed distribution service charge of $12.50 per month (including $0.01 for consumer education). As I previously explained, the fixed distribution service charge proposed by the Company will be closer to, but still less than, the customer-related costs identified by Ms. Ding in PECO Exhibit JD-5. Ms. Ding performed the Company's customer-cost analysis in the same manner as the customer-cost analysis presented by PPL Electric Utilities Corporation ("PPL Electric Utilities") in its 2012 electric base rate case, where its analysis was accepted and relied upon by the Administrative Law Judge and the Commission as the basis for the customer charges they approved in that case.[1]

Moreover, PECO's current residential fixed distribution service charge of $8.45 per month is lower than the residential customer charges of all but one of the six other major electric distribution companies in Pennsylvania, as shown on PECO Exhibit MK-3. PECO's proposed fixed distribution service charge is well within the range of the customer charges of other major Pennsylvania electric distribution companies and, in fact, is $4.61, or 36.9%, below PPL Electric Utilities' customer charge of $17.11.

Once the fixed distribution service charge was established, the revenue to be recovered from that 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 fixed distribution service charge.

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[1] *Pa. P.U.C. v. PPL Elec. Util. Corp.*, Docket No. R-2012-2290597, Recommended Decision (Oct. 19, 2012), pp. 118-120, and Final Order (Dec. 28, 2012), p. 131.

16. Q. Was the same general approach to rate design that you explained above for residential rates employed for the other rate classes?

A. Yes, it was. Fixed distribution service charges were changed to better reflect customer-related costs, and the variable distribution service charges of each rate schedule were changed to recover the remaining revenue in order to reach the class revenue target. Like the fixed distribution service charge for the residential class, fixed distribution service charges for other classes were designed to recover a greater proportion of each class' customer-related costs that were identified in PECO Exhibit JD-5.

IV. PROPOSED CHANGES IN THE DESIGN OF RATE HT

17. Q. Is PECO proposing any changes in Rate HT other than increases in the fixed and variable distribution service charges?

A. Yes, PECO is proposing to increase the High Voltage Distribution Discount for customers on Rate HT that receive service at voltages of 69 kV and higher, which will further reduce their rates. For customers served at 69 kV, the High Voltage Distribution Discount would increase from $0.48 to $1.29 per kW for the first 10,000 kW of measured demand. For customers served at voltages higher than 69 kV, the High Voltage Distribution Discount would also increase from $0.48 to $1.29 per kW for the first 100,000 kW of measured demand.

18. Q. Why is PECO proposing to increase the High Voltage Distribution Discount?

A. As explained by Ms. Ding in PECO Statement No. 6, the Company analyzed the configuration of customers served at 69 kV or higher to more clearly define the portion of substation facilities serving a distribution function they are using. PECO is proposing to increase the High Voltage Distribution Discount to provide an offset to those customers to reflect an appropriate allocation of distribution substation costs.

19. Q. How was the proposed increase to the High Voltage Distribution Discount calculated?

A. The proposed increase to the High Voltage Distribution Discount for customers served at 69 kV and higher is based on the level of distribution substation costs, including administrative and general expense and common and general plant. Those costs were isolated in the COS Study for Rate HT. Additional detail showing the calculation of the High Voltage Distribution Discounts is provided in PECO Exhibit JD-10.

V. EXISTING RIDERS BEING REVISED

20. Q. What existing riders does PECO propose to revise?

A. PECO is proposing to revise the Night Service GS Rider, the Night Service PD Rider and the Night Service HT Rider (collectively, the "NSRs").

21. Q. What are the NSRs?

A. The NSRs are riders that apply to eligible customers served on Rates GS, PD and HT for demand registered in off-peak hours that exceeds their demand during on-peak hours (as defined in the NSRs). Off-peak demand in excess of on-peak demand is billed at a demand charge that is lower than the Variable Distribution Service Charge under the customer's applicable rate schedule. A customer that qualifies for an NSR would, however, still be billed the Variable Distribution Service Charge for the demand it registers during on-peak periods. The NSRs recognize that peak demands registered by an eligible customer during off-peak hours do not drive the size – and, therefore, the cost – of certain facilities in the distribution system. Consequently, as explained in more detail by Ms. Ding in PECO Statement No. 6, the demand charges under the NSRs were calculated by excluding costs associated with facilities the size of which is not affected by a customer's off-peak demand, such as substations, which are sized to meet on-peak demand.

22. Q. How does PECO propose to change the NSRs?

A. In general, the demand charge of each NSR will be increased to better reflect the cost of off-peak demand calculated by Ms. Ding in the Company's COS Study. The off-peak demand cost calculated for the Night Service GS Rider is materially higher than the current Night Service GS Rider's demand charge. Therefore, to mitigate the impact on customers that use the Night Service GS Rider, PECO is proposing to continue the phase-in of the demand charge for that Rider, which was begun in its 2015 base rate case. Specifically, as part of the Company's last rate case, PECO increased the demand charge for the Night Service GS Rider from $1.03 per kW to $2.39 per kW of off-peak billing demand to implement that phase-in. As proposed, the demand charge for the Night Service GS Rider will be $3.00 per kW of off-peak billing demand versus an indicated cost of $4.79 per kW.

The off-peak demand cost calculated for the Night Service PD Rider is also materially higher than the current Night Service PD Rider's demand charge. As a result, PECO is proposing a demand charge for the Night Service PD Rider of $3.00 per kW of off-peak billing demand even though the indicated cost is $4.01 per kW. The demand charge proposed for the Night Service HT Rider aligns with the costs of providing off-peak service indicated by the Company's COS Study as shown on PECO Exhibit JD-6.

VI. CUSTOMER ASSISTANCE PROGRAM FIXED CREDIT OPTION TRANSITION COST RECOVERY

23. Q. Please briefly describe the genesis of PECO's CAP in-program arrearage forgiveness program.

A. On July 8, 2015, the Commission approved a settlement of the Company's CAP Design Proceeding at Docket No. M-2012-2290911. As part of that settlement, PECO agreed to propose an arrearage forgiveness program for its CAP customers. In broad terms, the program recognizes that PECO's CAP customer population has accumulated significant arrearages since entering the CAP program (known as "in-program arrearages" or "IPA"). In Docket No. M-2012-2290911, the parties also agreed that PECO would move to a new CAP design, known as the FCO, beginning in October 2016. The FCO is closely aligned with the Commission's affordability guidelines and is designed to provide affordable bills to PECO's CAP customers. However, large IPAs are an obstacle to achieving the goal of affordability because FCO bills plus payments required under payment arrangements to eliminate a large arrearage will impose financial obligations that are not affordable for CAP participants. Therefore, as part of the CAP design settlement, PECO agreed that, in its 2015 base rate case, it would propose an arrearage forgiveness program for its CAP customers.

24. Q. Did PECO implement a CAP arrearage forgiveness program under the terms of the 2015 rate case settlement?

A. Yes. The arrearage forgiveness provisions of the settlement divide financial responsibility for the accumulated IPAs by PECO's CAP customer population among three groups: (1) the CAP customers; (2) PECO – and, more specifically, PECO's shareholders; and (3) other residential customers. Each will be responsible for one-third of the accumulated arrearage, on a pro forma basis.

For each customer who was a CAP participant when PECO transitioned to the FCO program in October 2016, PECO determined the amount, if any, of that customer's IPA balance (the "Final IPA Balance"). PECO entered into a 60-month payment arrangement for an amount equal to one-third of that customer's Final IPA Balance. For each dollar of the customer's Initial IPA Balance that the customer pays via its payment arrangement or otherwise, the customer's Initial IPA balance will be reduced by an additional $2.00.

25. Q. Please describe the cost recovery mechanism for IPA forgiveness set forth in the 2015 base rate case settlement.

A. PECO guaranteed that it will not seek rate recovery of an amount equal to one-third of the collective final IPA balances of all CAP customers ("System Final IPA

Balance") in October 2016. As noted above, responsibility for that balance will be shared three ways and CAP customers will be assigned a share. The charge to recover the share for which a CAP customers is responsible is placed on the CAP customer's bill pursuant to the 60-month payment arrangement described above. The share borne by other residential customers is to be recovered through a $2 million base rate allowance ("2015 Base Rate Case Allowance") and a Universal Service Fund Charge ("USFC") matching amount. In particular, whenever a CAP customer makes a payment of $1.00 toward its IPA payment arrangement balance, PECO includes $1.00 for recovery through the USFC (the "USFC Matching Amounts"). PECO will forgive the remaining one-third as the share borne by it and its shareholders.

26. Q. Has PECO determined the System Final IPA Balance in the manner set forth in the 2015 rate case settlement?

Yes. As of October 14, 2016, when the FCO CAP design was implemented, the System Final IPA Balance amounted to approximately $30.1 million. In accordance with the 2015 rate case settlement, commencing with its USFC filing effective date, PECO applied a USFC correction factor to the 2015 Base Rate Case Allowance equal to the System Final IPA Balance divided by PECO's 2015 rate case IPA claim of $44.5 million. This formula was used to calculate an adjustment as shown on Exhibit MK-4 (the "USFC Adjustment") to ensure that the net sum of the 2015 Base Rate Case Allowance and the USFC Adjustment are the same ratio as the 2015 Base Rate Case Allowance divided by the 2015 base rate claim of $44.5 million.

27. Q. What expense adjustment is being proposed to reflect the implementation of the IPA forgiveness program?

A. PECO has made a pro forma adjustment of $3.6 million to add to the annual base rate expense in its FPFTY revenue requirement. This adjustment is reflected in PECO Exhibit BSY-1, Schedule D-11, and represents a three-year amortization of the portion of the System Final IPA Balance that PECO may recover from all residential customers as explained by Mr. Yin in PECO Statement No. 3. The amount being amortized, $10.9 million, is equal to two-thirds of the System Final IPA Balance, net of the following: (1) all revenues received through the 2015 Base Rate Case Allowance, as adjusted by the USFC correction factor; (2) all amounts paid by CAP customers toward their IPA payment arrangement balances; and (3) the USFC Matching Amounts. If PECO recovers more than two-thirds of the System Final IPA Balance, PECO will credit any accumulated over-collections back through its annual USFC filing. Additional detail showing the basis of the pro forma adjustment for the System Final IPA Balance is provided in PECO Exhibit BSY-1, Schedule D-11.

28. Q. Will the Company's proposed expense adjustment change the low-income customer experience with CAP in-program arrearage forgiveness?

A. No. The IPA forgiveness program will continue to operate just as it has been operating. Low-income customers who have a Final IPA Balance will continue to owe 1/60th of that balance on each monthly bill, and as they pay those amounts they will receive forgiveness of $2.00 for each $1.00 paid toward the Final IPA Balance. PECO's proposal only affects recovery of program costs; it does not affect the operation of the CAP IPA forgiveness program or the customer experience with the program.

VII. REVENUE EFFECT BY RATE SCHEDULE, PROOF OF REVENUES, AND SCALE-BACK

29. Q. Have you prepared a summary of revenue at present and proposed rates for each rate class?

A. Yes. PECO Exhibit MK-5 shows the revenue at both present rates and proposed rates, as well as the percentage increases each class will experience on an overall basis (cost of generation included).

30. Q. Have you prepared proofs of revenue with respect to PECO's present and proposed rates?

A. Yes. PECO Exhibit MK-6 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 MK-1 that addresses the increased revenue that would be required.

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 it is granted less than its requested increase, PECO proposes that:

(1) The revenue increases proposed for all rate classes be reduced in proportion to the proposed increase for each class; and

(2) The fixed distribution charges for all rate classes and location charges for street lighting 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.

VIII. 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 provide for a more accurate allocation of cost recovery and reduces intra-class and cross-subsidization.

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

A. Yes, it does.

PECO Energy Company
Proposed Revenue Allocation and Rate of Return by Rate Class

Rate	Current Distribution Revenue *	Proposed Distribution Revenue	Increase in Distribution Revenue	GSA/TSC Reduction	Net of GSA / TSC Revenue	2019 Tax Reform *	DSIC Revenue *	Net Revenue Ask	% Increase
Residential	$ 681,075,237	$ 761,755,068	$ 80,679,831	$ (2,541,346)	$ 78,138,485	$ (38,537,391)	$ 5,421,140	$ 45,022,234	6.6%
Residential Heating	$ 136,434,289	$ 156,510,399	$ 20,076,109	$ (698,334)	$ 19,377,775	$ (7,821,633)	$ 1,102,271	$ 12,658,413	9.3%
General Service	$ 224,850,669	$ 247,993,650	$ 23,142,981	$ (765,052)	$ 22,377,929	$ (12,818,581)	$ 1,818,734	$ 11,378,082	5.1%
Primary Distribution	$ 8,178,120	$ 8,988,063	$ 809,943	$ (13,337)	$ 796,606	$ (523,440)	$ 38,182	$ 311,348	3.8%
High Tension	$ 146,754,033	$ 166,725,114	$ 19,971,082	$ (430,769)	$ 19,540,312	$ (9,392,973)	$ 1,401,671	$ 11,549,010	7.9%
Electric Propulsion	$ 7,206,544	$ 8,367,254	$ 1,160,710	$ (16,452)	$ 1,144,258	$ (458,007)	$ 66,764	$ 753,015	10.4%
Lighting	$ 20,075,238	$ 21,225,334	$ 1,150,096	$ (3,554)	$ 1,146,541	$ (1,070,548)	$ 151,238	$ 227,231	1.1%
Total	$ 1,224,574,130	$ 1,371,564,882	$ 146,990,751	$ (4,468,845)	$ 142,521,906	$ (70,622,573)	$ 10,000,000	$ 81,899,333	6.7%

Rate	Present Rate of Return	Relative ROR	Proposed Rate of Return	Relative ROR
Residential	5.65%	0.98	7.79%	1.00
Residential Heating	4.50%	0.78	6.77%	0.87
General Service	6.63%	1.15	8.25%	1.06
Primary Distribution	6.46%	1.12	8.16%	1.05
High Tension	6.03%	1.05	8.10%	1.04
Electric Propulsion	3.65%	0.63	5.61%	0.72
Lighting	7.12%	1.24	8.10%	1.04
Total	5.76%		7.79%	

* Current Distribution Revenue for 2019 includes a revenue reduction for Tax Reform and additional DSIC revenue above 2018 levels

ELECTRIC PA P.U.C NO. 6
SUPERCEDES ELECTRIC PA P.U.C. NO. 5 AND ALL SUPPLEMENTS THERETO

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PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19101

For List of Communities Served, See Page 4.

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ISSUED BY: C. L. Adams – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19101

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

Definition of Terms and Explanations of Abbreviations – Original Page No. 7 and Original Page No. 8 - Interest index – definition added. Service – added verbiage for clarity.

Rule 2.2 SINGLE-POINT DELIVERY – Original Page No. 10 - Added verbiage for clarity.

Rule 2.5 SINGLE-PHASE UP TO 150 KVA - Original Page No. 11 – Revised to include parallel generation.

Rule 3.7 NONSTANDARD SERVICE - Original Page No. 12 - Added verbiage for clarity.

Rule 4.2 SERVICE CONTRACT Original Page No. 12 - Added verbiage for clarity.

Rule 6.3 CUSTOMER'S SERVICE EXTENSION – Original Page No. 14 – Clarified responsibility for customer owned facilities.

Rule 7.2 LINE EXTENSIONS FOR STANDARD SERVICE - Original Page No. 16 - Added existing practice for detailed design.

Rule 7.3 UNDERGROUND SERVICE IN NEW RESIDENTIAL DEVELOPMENTS - Original Page No. 17 - A citation of 52 Pa. Code § 57.81 was added.

Rule 10.2 CUSTOMER'S RESPONSIBILITY - Original Page No. 19 – Added verbiage that reinforce the Act 287 obligations.

Rule 14.10 – Original Page No. 24 - The existing Rule 14.11 will be renumbered as Rule 14.10.

Rule 15.3 POWER FACTOR ADJUSTMENT - Original Page No. 25 – Revised to clarify how power factor is billed.

Rule 17.2 BILLING OPTIONS – Original Page No. 26 - Alignment with Gas tariff clarifying that the EGS is responsible for communicating the customer's billing option to PECO.

Rule 17.5 LATE FEES AND COLLECTION COSTS - Original Page No. 26 – Added existing practice for final bills.

Rule 22.1 DESIGNATION OF PROCUREMENT CLASS - Original Page No. 30 - Revised verbiage in paragraph F and G for clarity.

Rule 23.8 EGS SWITCHING - Original Page No. 31 - New rule added under EGS Switching to align the Electric Tariff with the Gas Service Tariff rule 21.2.

FEDERAL TAX ADJUSTMENT CREDIT (FTAC) – Original Page No. 33 - Page added.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW - Original Page No. 34 – Added verbiage for clarity and working capital price updated.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW - Original Page No. 26 Added verbiage for clarity and working capital price updated.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) – Original Page No. 40 - Removing selected phase-out language.

TRANSMISSION SERVICE CHARGE (TSC) - Original Page No. 42 - Working capital price updated.

SMART METER SURCHARGE - Eliminated

RATE R RESIDENCE SERVICE – Original Page No. 59 - Revised the "Availability" provisions of Rate R regarding detached garages and farms. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC). Distribution prices updated.

RATE R H RESIDENTIAL HEATING SERVICE – Original Page No. 50 - Language deleted. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC). Distribution prices updated.

RATE RS-2 NET METERING – Original Page No. 52 - Paragraph 3 - added clarifying verbiage in regards to virtual net meeting.

RATE-GS GENERAL SERVICE – Original Page No. 54 Adding "farms" to the Rate GS availability provisions to align with the farm-related revisions that PECO is proposing to Rate R. Distribution prices updated. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC). Added 1500 kVA limit for 120/208 and 277/480 volt services with outdoor transformation.

RATE-PD PRIMARY DISTRIBUTION POWER - Original Page No. 56 - Distribution prices updated. Added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

RATE-HT HIGH TENSION POWER - Original Page No. 57 - Distribution prices updated. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

RATE-EP ELECTRIC POLPUSION - Original Page No. 58 - Distribution prices updated. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

RATE POL PRIVATE OUTDOOR LIGHTING – Original Page No. 59 - Revisions made to rate schedules and standardize terms.

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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIES – Original Page No. 61 - Revisions made to rate schedules and standardize terms. Distribution prices updated. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

RATE SL-E STREET LIGHTING CUSTOMER OWNED FACILITIES Original Page No. 61, 62, 63 Moved paragraph 6 for Service to the first paragraph under "Terms and Conditions" and added verbiage to DETERMINATION OF ENERGY BILLED for clarity. Distribution prices updated. Also, added FEDERAL TAX ADJUSTMENT CREDIT (FTAC). Removal of "DETERMINATION OF BILLED DEMAND".

RATE SL-C SMART LIGHTING CONTROL CUSTOMER OWNED FACILITIES – Original Page No. 65 - New rate added for customer-owned street lighting facilities with smart control technology.

RATE TLCL TRAFFIC LIGHTING CONSTANT LOAD SERVICE– Original Page No. 68 - Distribution prices updated. Added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

RATE BLI BORDERLINE INTERCHANGE SERVICE – Original Page No. 69 – Replace Service Charge with reference to applicable PECO base rate schedule.

RATE AL ALLEY LIGHTING IN CITY OF PHILADELPHIA –. Original Page No. 70 - Service Location Charge updated. Added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

APPLICABILITY INDEX OF RIDERS – Original Page No. 71 - Updated to include new Electric Vehicle Pilot Rider.

PILOT CAPACITY RESERVATION RIDER (CRR) – Original Page Nos. 72 - 76 - Added definitions and added wording for clarity.

CONSTRUCTION RIDER – Original Page No. 81 -Added verbiage for clarity.

ECONOMIC DEVELOPMENT RIDER – Original Page No. 82 - "Under the Competitive Alternative section, added verbiage for clarity. Under the Rate Reduction section, added language concerning negotiation of the rate reduction and payment terms."

ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) – Original Page No. 84 - New pilot rider added.

NIGHT SERVICE GS RIDER – Original Page No. 88 - Added verbiage for clarity. Rate table updated. Added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

NIGHT SERVICE HT RIDER – Original Page No. 89 - Added verbiage for clarity. Rate table updated. Added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

NIGHT SERVICE PD RIDER – Original Page No. 90 - Added verbiage for clarity. Rate table updated. Added FEDERAL TAX ADJUSTMENT CREDIT (FTAC).

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Deleted: **Generation Supply Adjustment for Procurement Classes 1 and 2 Loads Up to 100 KW – 9th Revised Page No. 32 and 9th Revised Page No. 33.**
Reflects quarterly adjustments to the GSA 1 and 2 Procurement Classes pursuant to the Order at Docket No. P-2016-2534980.

Generation Supply Adjustment for Procurement Class 3/4 Loads Greater than 100 KW – 20th Revised Page No. 34
Reflects quarterly adjustment for the GSA 3/4 Hourly Pricing Procurement Class pursuant to the Order at Docket No. P-2016-2534980

Deleted: **Rate R –Residence Service – 22nd Revised Page No. 48**
Clean-up page which reflects all rate changes effective January 1, 2018.

Rate RH – Residential Heating Service – 22nd Revised Page No. 49
Clean-up page which reflects all rate changes effective January 1, 2018.

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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, Narberth, Norwood, Parkside, Prospect Park, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Haverford, Lower Chichester, Lower Merion, 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, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

FIRST-CLASS TOWNSHIPS: Abington, Cheltenham, Hatfield, Lower Moreland, Lower Pottsgrove, Plymouth, Springfield, Upper Dublin, Upper Gwynedd, Upper Moreland, Upper Pottsgrove, West Norriton, West Pottsgrove, Whitemarsh.

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, 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, TLCL, EP, and AL.

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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 - 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 - 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, 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, or 230,000 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 or 230,000 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 13,200 or 33,000 volts, where the customer's demand exceeds 7,000 kW, the owner may be required to provide a suitable location on the premises for the installation of Company's transformation equipment.

  The Company's charges for service, which are comprised of the Fixed Distribution Service Charge and Variable Distribution Service Charge, are nonbypassable 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)¶
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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.

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Variable Distribution Service Charge - the variable energy 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.

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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. Generating systems shall be installed and operated under Rate RS-2 with associated load sharing the same electric point of interconnection to the Company's facilities. 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.)

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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.

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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, contactors 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.

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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 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 PLACE OF APPLICATION. Customers may apply for service at the Company's Principle Office 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 ("Gray Book, "Yellow Book") 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 **(C)** 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

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(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 or through in-person identification; (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.

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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 secondary 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.

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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 or transformer on customer-owned property or facilities; Such installation does not alter the responsibility of the customer to provide, own, inspect, and maintain such facilities.

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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").

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(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 surety bond in the amount of 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 surety bond.

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.

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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. 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.

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.

(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.

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.

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.

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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.

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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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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.

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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.

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.

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RULES AND REGULATIONS (continued)

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.

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.

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 render "short period" bills as needed 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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Deleted: 14.10 PROVISIONS FOR CUSTOMER REQUESTED SMART METERS. Once all necessary infrastructure is complete but not later than October 2012 a customer may request that PECO install a smart meter ahead of the planned schedule for their property however the customer must pay the incremental cost of installing the meter outside of the normal installation schedule. For residential and single phase commercial customers the cost is $17. In the case of more complex meter arrangements the Company shall provide the estimated cost and the customer shall pay the cost prior to the installation.¶
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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 in advance.

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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. The power factor of all customers not included under the provisions of paragraphs (a) or (b) shall be determined by test at a time when the customer's load is not less than two-thirds of the customer's maximum measured demand in the preceding eleven months; or, at the option of either the customer or the Company, by

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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 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.

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 open to the general public, 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.

(b) Payment may be made at any commercial office of the Company or 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 a Company office or 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. 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. These terms also apply to Final Bills as defined in Tariff Rule 20.2.

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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, POL 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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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.**

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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 Consistent with 52 PA Code §56.100, the Company will accept the following most current and valid documents as proof of household income: (1) income tax returns; (2) pay stubs; (3) benefit letters and governmental agency verification; (4) other forms to be accepted at the Company's discretion. The customer must provide this information within 10 days of the Company's request. This information may also be used by the company to determine deposit requirements, payment arrangements, and any other income specific program.

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.

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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. In the case of fraud, the reconnection charge will also include allocated overheads, all investigative costs, and administrative costs as determined by the Company. All theft and fraud reconnections will be completed at the premise and will not be performed remotely.

	Reconnect Fees For Non-Payment	Reconnect Fees For Theft / Fraud
Electric Reconnect at the Meter	**$ 75.00**	**$ 350.00**
Electric Reconnect at Tap	**$ 260.00**	**$ 1,180.00**
Electric Reconnect - Underground dig	**$ 1,650.00**	**$ 4,450.00**
Electric with dual meters	**$ 100.00**	**$ 350.00**
Electric Remote Reconnect (one or dual meters)	**$ 20.00**	**N/A**

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.

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 account 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 surcharge credit value of 0.01% will apply to all PaPUC jurisdictional distribution charges in the Base Rates and Riders, effective January 1, 2018.

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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FEDERAL TAX ADJUSTMENT CREDIT (FTAC)

A credit value of x.xx% will apply to all PaPUC jurisdictional distribution charges, during the period XXX X, XXXX through XXX X, XXXX, to pass the 2018 effects of the Tax Cuts and Jobs Act ("TCJA") to customers. The FTAC will be computed annually, will be effective ten days after filing, and will continue until the effect of the change in tax rates resulting from the TCJA has been refunded to customers.

The FTAC will be based on the difference in total annual revenue requirement before and after implementing the 2018 effects of the TCJA and the calculation will reflect the reduction in required revenues. The reduction in required revenues will be divided by estimated annual applicable base revenues to develop the FTAC to be applied to customers' bills for service rendered during the twelve-month period beginning XXX, X. The difference between the actual reduction in required revenue and the reduction in revenues produced by the FTAC as applied will be subject to refund or recovery in an annual revision to the FTAC. The interest rate on the over or under collection will be applied 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. For any over/under credit balance that remains after XXX X, XXXX, the Company may propose additional FTAC adjustments to ensure that the balance is eliminated.

An annual reconciliation statement will be submitted to the Commission by XXX of each year. A final reconciliation statement will be filed within 30 days after the final over/under balance has been eliminated. The FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW

Applicability: June 1, 2017 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.

Pricing: 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 pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2017. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2017 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 generation service charge shall be calculated using the following formula:

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 quarterly period, the spot market purchases for the quarterly period, plus the cost of any other energy acquired for the quarterly 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 C component above for the quarterly 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 March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) 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 March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) 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 = $0.00019/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:

Rate		GSA Price
R	GSA (1)	$0.06401
RH	GSA (1)	$0.06401
GS	GSA (2)	$0.06014

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

PD	GSA (2)	$0.05911
HT	GSA (2)	$0.05670
POL*	GSA (2)	$0.04554
SL-S*	GSA (2)	$0.04554
TLCL	GSA (2)	$0.06014
SL-E*	GSA (2)	$0.04554
AL*	GSA (2)	$0.04554

* Prices shall exclude capacity from the Procurement Class 2 RFP results.

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1, September 1, December 1 and March 1 in conjunction with the Reconciliation Schedule.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2017 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, 2017 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

ΣPJM_{DA} 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} x Usage*1/(1-LL) + AEPS/S_{AEPS} 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 = $0.00019 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)	$0.00506	$0.00500	$0.00486	$0.00486

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

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RECONCILIATION

Applicability: June 1, 2017 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, 2016 through December 31, 2016 reconciliation period for Procurement Classes 1 and 2 and the six month period July 1, 2017 through December 31, 2017 for Procurement Class 3/4 Hourly. There will be two initial transition reconciliation periods for Procurement 3/4 Hourly. They are the reconciliation period including February 2017 and the reconciliation period including the four month period March 1, 2017 through June 30, 2017, respectively. 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 and for Procurement Class 3/4 Hourly after the transition period, any over/(under) recovery shall be collected after the occurrence of two months from the end of the reconciliation period. For the two initial transition reconciliation periods for Procurement Classes 3/4 Hourly any over/(under) recovery shall be collected after the occurrence of three months and two months, respectively. For Procurement Classes 1, 2 and 3/4 Hourly, recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2017 through August 31, 2017 for Procurement Classes 1 and 2 and March 1, 2018 through August 31, 2018 for Procurement Class 3/4 Hourly. For Procurement Class 3/4 Hourly, the two initial transition recovery periods corresponding to the two initial transition reconciliation periods are June 1, 2017 through August 31, 2017 and September 1, 2017 through February 28, 2018, respectively. 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 100 kW, and Class 3/4 – Large C&I greater than 100 kW.

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 **(C)** 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. This interest rate basis becomes effective with January 2016 over or under collections

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 for Procurement Classes 1 and 2, and for Procurement Class 3/4 Hourly after the two initial transition periods, shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months. For the two initial transition periods for Procurement Class 3/4 Hourly, the initial 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 three months and two months, respectively. For Procurement Classes 1, 2 and the 3/4 Hourly the GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2017 with over/under collection recovery occurring over the six month period beginning September 1 and March 1. For Procurement Class 3/4 Hourly, the two initial transition recovery periods for over/under collections are June 1, 2017 through August 31, 2017 and September 1, 2017 through February 28, 2018. 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%

<u>Formula</u>
The following formula shall be used to determine the NDCA.

$$\text{NDCA} = \frac{\text{PaPUC Authorized Decommissioning Expense Adjustment}}{\text{Total Pennsylvania Jurisdictional Sales for Calculation Year}}$$

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, 2018, 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 ($0.03)/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.

<u>Methodology for Calculating Expense</u>
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	$2,992,000
Peach Bottom 2	2,588,000
Peach Bottom 3	5,976,000
Salem 1	2,651,000
Salem 2	2,509,000
Limerick 1	4,403,000
Limerick 2	8,043,000
Total	$29,162,000

<u>Frequency of Calculation</u>
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.

<u>Completion of Decommissioning</u>
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 credit ($0.00187) 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:

$$\text{USFC} = \frac{(C+L-E-I) + F}{(S)}$$

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 discounts provided to CAP customers (CAP revenue shortfalls) recovered through base rates and total CAP discounts, net of a 27% offset factor.

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. 2017 projected costs include the incremental LIURP and De-facto heating audit spend beginning in October 2017 which is the result of the settlement at Docket No M-2012-2290911. This additional audit spend will occur for a three year period from October 2017 through September 2020.

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.

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.

F- Correction Factor of the In-Program Arrearage Forgiveness Program which was the result of the settlement at Appendix C of Docket No R-2015-2468981. This Correction Factor adjusts the $2M recovery included in base rates. The $2M was based upon the estimated Accounts Receivable balance ("A/R") of CAP customers at the time of the settlement. The Correction Factor adjusts the $2M recovery to the final ending balance of the A/R at the time of conversion to the new CAP/FCO program. The Correction Factor will be used for the period of 2016 through 2021.

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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out benefit of $50 per qualified CAP customer. This is the result of the settlement at Docket No M-2012-2290911 which focuses on the new CAP Fixed Credit Option ("FCO") which will begin in October 2016.

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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 for the transition to a competitive energy market. The proposed plan shall consist of the cost of the consumer education plan approved in Docket M-2008-2032274 and P-2008-2062739. Included in these costs shall be the cost of educating customers on available mitigation options such as the Voluntary Market Rate Phase-In Rider.

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 procurement class. The current Consumer Education Plan Cost for each Class 1 is a 1.0 charge credit per month for Rates R, RH and CAP, Class 2 and 3 is a 1.0 cent credit per month for Rate GS and for Class 4 is 0 cent credit per month for Rates HT and PD with an April 1, 2017 effective date.

Billing Provisions: The surcharge shall be calculated on an annual basis using the following formula:

$$MC(n) = \frac{(C+S+E+I)}{R(n)} \times \frac{1}{(1-T)}$$

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 coming transition to a 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. Also includes the costs of the new residential Customer Assistance Program (CAP) consumer education program per Docket No. M-2012-2290911.

MC(n) = consumer education cost and supplier–oriented bill cost per customer for procurement 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

S – The cost of implementing the supplier-oriented bill as approved in the Final Order at Docket No. M-2014-2401345.

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.

N – Procurement 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 procurement 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 $221 per mW. WC is a component of the 'C" factor

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, 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= $.00698 per kilowatthour
RH= $.00698 per kilowatthour
Small C&I = $1.54 per billed kW
Large C&I = $0.91 per billed kW
Street Lighting = $.00064 per kilowatt hour

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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, 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= $.00292 per kilowatthour
RH= $.00292 per kilowatthour
Small C&I = $0.52 per billed kW
Large C&I = $0.82 per kW based on the PJM PLC
Street Lighting = $.00039 per kilowatt hour

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PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT (TARC)

Purpose: The purpose of this credit is to provide customers a bill credit for the tax benefits gained as a result of a change in the method of tax accounting for certain expenditures. The Tax Accounting Repair Credit is as proposed in the Settlement at Docket No. R-2010-2161575 in Section II E(2) and the Settlement at Docket No. R-2015-2468981 in Section II E (20).

Applicability: The credit shall be calculated to the nearest one-hundredth of a cent for billing purposes for all customers, except for customers on Rates SLE, SLS, POL, TLCL and AL where it shall be the nearest one cent. The TARC shall be credited to each rate schedule as follows:

Rate R	($0.0019)/kWh
Rate RH	($0.0019)/kWh
Rate GS	($0.0013)/kWh
Rate POL	($0.52)/lamp
Rate SL-S	($6.25)/lamp
Rate SL-E	($0.52)/location
Rate AL	($0.52)/location
Rate TLCL	($0.52)/location
Rates HT, PD, EP	($0.0004)/kWh

The Variable Distribution Service charges, for the above rate schedules shall include the above listed TARC credits. For the lighting rate schedules, the applicable location or fixed distribution service charges shall include the TARC credit.

Calculation of TARC Credit:
Billing Provisions: The credit shall be calculated by rate schedule using the following formula:

$$\textbf{TARC} = \frac{\textbf{R(n)+I}}{\textbf{BU(n)}} \times \frac{\textbf{1}}{\textbf{(1-T)}}$$

R(n) – The amount accrued as a result of a change in the tax accounting method for electric system repairs for rate class n divided by 7.

I - Interest on the bill credit. Interest shall be at a rate of 6% simple interest and shall be calculated on the monthly unamortized balance of the tax effected catch-up deduction.

BU(n) – The total annual Billing Units for the rate class.

T - The current Pennsylvania gross receipt tax rate included in base rates.

Filings and Reconciliations: One year prior to the scheduled expiration of the credit the Company will evaluate whether a change in the credit is required in order to avoid a significant over or under recovery at the end of the rate credit period. If a base rate case has not been filed prior to the expiration of the credit, a final reconciliation filing will be made on or before January 31, 2019, at which time any under or over recoveries will be reflected in rates in effect from April 1, 2019 to June 30, 2019. If it is apparent that such methodology would result in a significant over or under recovery at December 31, 2018 for an individual rate class the Company will propose a revised rate credit to become effective April 1, 2018. Interest will not be applied to any over or undercollections for the bill credit prior to January 1, 2016. Starting on January 1, 2016 the bill credit will reflect 6% simple interest on the monthly unamortized balance of the tax-effected catch-up deduction in accordance with the Settlement at Docket No. R-2015-2468981 in Section II E (20). If the amount to be credited to customers is modified based upon the results of an IRS audit of the accounting change, the Company shall modify the credit accordingly through a filing with the Commission. Such filing shall be made 60 days prior to the effective date. Additionally, if the value of the credit has been reduced due to a State Net Operating Loss (NOL), a filing shall be made to increase the credit when the NOL has been used by the Company.

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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 III 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 III

Rates R, RS, RH:	$0.00237/kWh
Rates GS:	($0.00048)/kWh
Rate SL-E:	($0.06)/location
Rate AL:	($0.02)/location
Rate TLCL:	($0.00090)/kWh
Rates HT, PD, EP:	$0.16/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:

$$\textbf{EEPC(n)} = \frac{(C\text{-}E)+(SWE)}{(BU)} \times \frac{(1)}{(1\text{-}T)}$$

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. Any direct load control benefits to the Company from the programs shall be credited against the cost. The program costs are those approved by the PAPUC and audit costs for the Phase III program ending May 31, 2021

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.

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, AL, TLCL

Filings and Reconciliations: The estimated EEPC shall be filed by May 1 each year to be effective June 1. The first surcharge, effective June 1, 2016 will contain "C" and "E" factors calculated as follows: The "C–factor" will have two components; one including Phase II costs and the other including Phase III costs. The Phase III component will be set using projected costs for the 12 month period from June 1, 2016 through May 31, 2017. The Phase II component will be set using any Phase II costs from projects started prior to the end of Phase II, but not yet billed as of June 1, 2016. For the "E-factor" over/under rate will include the Phase II costs for the 10 month period from June 1, 2015 through March 31, 2016.

The second EEPC, effective June 1, 2017, will be calculated as follows: the "C-factor" will include Phase III costs for the period June 1, 2017 through May 31, 2018 and the "E-factor" will include costs for 12 months comprising Phase II costs for the 2 months of April and May 2016 and Phase III costs for the 10 months of June 1, 2016 through March 31, 2017. 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 II only reconciliation statement will be for the 10 month period from June 1, 2015 through March 31, 2016. Phase III reconciliation statements will be for the 12 month period April 1 through March 31 of each plan year. The first Phase III reconciliation statement will cover the period April 1, 2016 through March 31, 2017 and include 2 months (April and May) of Phase II revenues and expenses and 10 months of Phase III revenues and expenses (June through March).

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DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge 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 a natural gas distribution company or city natural gas distribution operation 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:

$$DSIC = \frac{(DSI * PTRR)+Dep+e}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation.

PTRR = Pre-tax return rate applicable to DSIC eligible property.

Dep = Depreciation expense related to DSIC-eligible property.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit, as described below.

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PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be gained or lost by the beginning of the applicable service period.

Revenue shall be based upon one-fourth of the estimated annual distribution revenue.

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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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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: $12.50
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $1.94

VARIABLE DISTRIBUTION SERVICE CHARGE:
All kWhs $0.06267 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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT, AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

PAYMENT TERMS. Standard.

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RATE R H 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: $12.50
FIXED DISTRIBUTION SERVICE CHARGE FOR FORMER OFF-PEAK METERS: $1.94

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
$0.06267 per kWh for all kWh.
WINTER MONTHS. (October through May)
$0.04848 per kWh for all 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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, UNIVERSAL SERVICE FUND CHARGE NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

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. This Rate is limited to installations where the renewable energy generating system is intended primarily to offset part or all of the customer-generator's requirements for electricity. 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.

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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.

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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.

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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.

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RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to 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.

2. 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.

3. 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.

4. 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.

5. 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.

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.

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RATE RS-2 NET METERING (continued)

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 to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The installation cannot be directly connected to the Company's distribution system ("stand alone"). Instead, the installation must be connected to a facility (residence or business) that is connected to the Company's distribution system.

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 through a single metering installation for offices, professional, commercial or industrial establishments, governmental agencies, farms and other applications outside the scope of the Residence Service rate schedules.

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 of the parallel-generating capacity exceed 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:
$ 14.53 for single-phase service without demand measurement, or
$ 18.52 for single-phase service with demand measurement, or
$ 44.36 for polyphase service.

VARIABLE DISTRIBUTION SERVICE CHARGE:
$8.46 per kW of billed demand
($0.00190) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: ($0.00048) 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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS APPLY TO THIS RATE.

DETERMINATION OF 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 demand up to 500 kW, the billing demand shall be the measured demand, with a minimum billing demand of 1.2 kW.
For customers with demand greater than 500 kW, the billing demand shall be the greater of (i) the measured demand, (ii) 40% of the maximum contract demand; or (iii) the maximum measured demand from the prior year.

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. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus a charge of $4.96 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 fire fighting 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.
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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: $296.10

VARIABLE DISTRIBUTION SERVICE CHARGE:
$7.42 per kW of billing demand
($0.00100) per kWh for all kWh

ENERGY EFFICIENCY CHARGE: $0.16 per kW of Peak Load Contribution

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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), NUCLEAR DECOMMISSIONING COST ADJUSTMENT PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS 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. 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: $299.63

VARIABLE DISTRIBUTION SERVICE CHARGE:
$5.23 per kW of billing demand
($0.00100) per kWH for all kWh

HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For customers supplied at 33,000 volts: $0.15 per kW of measured demand.
For customers supplied at 69,000 volts: $1.29 per kW for first 10,000 kW of measured demand.
For customers supplied over 69,000 volts: $1.29 per kW for first 100,000 kW of measured demand.

ENERGY EFFICIENCY CHARGE: $0.16 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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT 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.

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:
$4.75 per kW of billing demand
($0.00100) per kWh for all kWh

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HIGH VOLTAGE DISTRIBUTION DISCOUNT:
For delivery points supplied at 33,000 volts: $0.15 per kW.
For delivery points supplied at 69,000 volts: $1.29 per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts $1.29 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 3/4.

ENERGY EFFICIENCY CHARGE: $0.16 per kW of Peak Load Contribution

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service Charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT 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.

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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

PRICE PER LIGHTING UNIT

MERCURY-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	DISTRIBUTION (Cust.Pole)
100 Watts (nominally 4,000 Lumens)	$13.71	$12.21
175 Watts (nominally 8,000 Lumens)	$18.72	$17.28
250 Watts (nominally 12,000 Lumens)	$23.15	$21.87
400 Watts (nominally 20,000 Lumens)	$29.92	$28.23
400 Watts Floodlight (nominally 22,000 Lumens)	$32.44	$30.75

SODIUM-VAPOR LAMPS	DISTRIBUTION (Co.Pole)	DISTRIBUTION (Cust.Pole)
70 Watts (nominally 5,800 Lumens)	$18.99	$17.52
250 Watts (nominally 25,000 Lumens)	$30.35	$28.66
400 Watts (nominally 50,000 Lumens)	$33.21	$31.52
400 Watts Floodlight (nominally 50,000 Lumens)	$35.71	$34.02

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)	DISTRIBUTION (Cust.Pole)
100 Watts (nominally 7,800 Lumens)	$28.41	$27.45
175 Watts (nominally 13,000 Lumens)	$29.81	$28.04
250 Watts (nominally 20,500 Lumens)	$31.54	$29.79
400 Watts (nominally 36,000 Lumens)	$35.16	$33.51
1000 Watts (nominally 110,000 Lumens)	$61.53	$59.91

HIGH PRESSURE SODIUM VAPOR LAMPS	DISTRIBUTION (Co.Pole)	DISTRIBUTION (Cust.Pole)
50 Watts (nominally 4,000 Lumens)	$18.86	$17.39
70 Watts (nominally 5,800 Lumens)	$21.43	$19.79
100 Watts (nominally 9,500 Lumens)	$22.65	$21.01
150 Watts (nominally 16,000 Lumens)	$24.74	$23.11
250 Watts (nominally 25,000 Lumens)	$29.05	$27.39
400 Watts (nominally 50,000 Lumens)	$35.22	$33.57
1,000 Watts (nominally 130,000 Lumens)	$40.58	$39.94

LIGHT-EMITTING DIODE LAMPS	DISTRIBUTION (Co.Pole)	DISTRIBUTION (Cust.Pole)
5 Watts (nominally 3,300 Lumens)	$31.25	$29.71
53 Watts (nominally 5,000 Lumens)	$32.03	$30.50
87 Watts (nominally 8,300 Lumens)	$33.08	$31.54
163 Watts (nominally 15,800 Lumens)	$36.02	$34.48
215 Watts (nominally 20,000 Lumens)	$37.78	$36.25

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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT 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 delivery point 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.

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, luminaries 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.

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 unit shall be for at least three years.

PAYMENT TERMS.
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1. Standard Lighting Unit. 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.¶
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2. Standard Installations. In connection with the standard service provided herein, the Company will install, own and maintain all facilities within highway limits, and 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.¶
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.¶
For underground supply furnished at the request of the customer where aerial supply would be normal, the Company will assume the cost up to the amount it would normally have invested and the additional cost shall be assumed by the customer.¶
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RATE SL-S STREET LIGHTING-SUBURBAN COUNTIE

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	$ 88.52
600 Lumens	58	$126.57
1,000 Lumens	103	$178.76
2,500 Lumens	202	$247.99
6,000 Lumens	448	$282.48
10,000 Lumens	690	$342.74

Mercury Vapor Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
4,000 Lumens	115	$211.51
8,000 Lumens	191	$223.32
12,000 Lumens	275	$238.08
20,000 Lumens	429	$280.11
42,000 Lumens	768	$400.72
59,000 Lumens	1,090	$451.11

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	$210.00
9,500 Lumens	131	$228.71
16,000 Lumens	192	$257.37
25,000 Lumens	294	$292.79
50,000 Lumens	450	$349.45

Light-Emitting Diode Lamps

Size of Lamp (Nominal)	Billing Watts	Distribution
3,300 Lumens	35	$374.93
5,000 Lumens	53	$384.40
8300 Lumens	87	$396.94
15,800 Lumens	163	$432.25
20,000 Lumens	215	$453.40

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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT, APPLY TO THIS RATE.

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RATE SCL SMART CONTROL LIGHTING CUSTOMER OWNED FACILITIES¶
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AVAILABILITY. ¶
<object>The Smart Control Option is available to any governmental agency for outdoor lighting provided for the safety and convenience of the public of streets, highways, bridges, parks or similar places who chooses to have PECO provide a Sensus Vantage Point module for the lamp or to any customer who has obtained similar controls for their lighting system and can provide energy usage upon request by the Company 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. ¶
All facilities and their installation shall be approved by the Company.¶
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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 delivery point 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, luminaries 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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<#>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 to the Company's monthly Variable Distribution Service charges. If the customer ¶
receives Default service, the outage allowance will also apply to the Energy & Capacity and Transmission Charges. The monthly bill will be adjusted, pro rate, for the hours of failure if such failure continues for a period in excess of 12 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.¶
<#>Lighting Installations. 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.¶
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Standard lighting installations under standard conditions of supply will be made on the public highways at the expense of the Company to the extent warranted by the revenue in prospect, any additional investment to be assumed by the customer.¶
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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:	$6.07 per Service Location (as defined below) *
VARIABLE DISTRIBUTION CHARGE:	$0.01691 per kWh

ENERGY SUPPLY CHARGE: Refer to the Generation Supply Adjustment Procurement Class 2.

* The service location charge includes an Energy Efficiency Program Surcharge of ($0.06) per location

TRANSMISSION SERVICE FOR CUSTOMERS RECEIVING DEFAULT SERVICE: The Transmission Service charge shall apply.

STATE TAX ADJUSTMENT CLAUSE, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location shall comprise each lighting installation and must be separately connected to a delivery point on the Company's secondary circuit.

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 comprising the brackets, hangers, luminaries, lamps, ballasts, 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.
   b. Service Locations Supplied from Underground Circuits: customer shall provide, own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90 degree pipe bend, brackets or hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors and conduits from the lamp receptacles to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a delivery point designated by the Company on its secondary voltage circuit, and shall assume all costs of installing such utilization facilities.
   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 delivery point and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided.
   c. Service to Group of Streetlights:

   AERIAL SUPPLY
   When the customer requests service to a group of streetlights supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the streetlights. 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 streetlight locations.

   UNDERGROUND SUPPLY
   When groups of streetlights are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each streetlight from the designated delivery point. If the customer requests an underground supply to a group of streetlights and the designated delivery point 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. 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.

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 lamp receptacle 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.

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 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 streetlight 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.

MONTHLY RATE TABLE.
SERVICE LOCATION DISTRIBUTION CHARGE: $5.05 per Service Location (as defined below)
VARIABLE DISTRIBUTION CHARGE: $0.0325 per kWh

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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

SERVICE LOCATION.
A Service Location shall comprise each lighting installation and must be separately connected to a delivery point on the Company's secondary circuit.

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:

(A) Manufacturer-rated wattage
(B) Annual burning hours, if different than the standard 4,100 burning hours as defined below under paragraph 1 Service of Terms and Conditions
(C) 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 pas 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 comprising the brackets, hangers, luminaries, lamps, ballasts, transformers, Company-approved Smart Control Modules, 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.
   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90 degree pipe bend, brackets or hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors and conduits from the lamp receptacles to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a delivery point designated by the Company on its secondary voltage circuit, and shall assume all costs of installing such utilization facilities.
   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 delivery point and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided.
   c. Service to Group of Streetlights:
      AERIAL SUPPLY
      When the customer requests service to a group of streetlights supplied from aerial distribution facilities, the customer is responsible for providing the support poles or posts for the streetlights. 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 streetlight locations.
      UNDERGROUND SUPPLY
      When groups of streetlights are supplied from underground distribution facilities, the customer is responsible for the supporting poles or posts and the supply conductors to each streetlight from the designated delivery point. If the customer requests an underground supply to a group of streetlights and the designated delivery point 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 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. 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 lamp receptacle 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.

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: $3.18 PER LOCATION

VARIABLE DISTRIBUTION SERVICE CHARGE: $0.01569 per kWh (as defined below)*
*The Variable Distribution charge includes an Energy Efficiency Program Surcharge of ($.00090) per kWh

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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY, NON-BYPASSABLE TRANSMISSION CHARGE, CONSERVATION PROGRAM COSTS PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT APPLY TO THIS RATE.

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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STATE TAX ADJUSTMENT CLAUSE, NUCLEAR DECOMMISSIONING COST ADJUSTMENT, THE ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS APPLY TO THIS RATE.¶
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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: $1.86 Per Location (as defined below)*
*The service location charge includes an Energy Efficiency Program Surcharge of ($0.02)

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, FEDERAL TAX ADJUSTMENT CREDIT (FTAC), PROVISION FOR THE RECOVERY OF CONSUMER EDUCATION PLAN COSTS, PROVISION FOR THE RECOVERY OF ENERGY EFFICIENCY AND CONSERVATION PROGRAM COSTS, NON-BYPASSABLE TRANSMISSION CHARGE, PROVISION FOR THE TAX ACCOUNTING REPAIR CREDIT AND NUCLEAR DECOMMISSIONING COST ADJUSTMENT CLAUSE APPLY TO THIS RATE.

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	72-76			X	X	X	X					X		
CAP Rider	77	X	X											
Casualty	78			X	X	X	X					X		
Commercial/ Industrial Direct Load Control Program Rider	79-80													
Construction	81					X	X					X		
Economic Development	82-83				X	X	X							
Electric Vehicle DCFC Rider (EV-FC)	84-85				X	X	X							
Emergency Energy Conservation	86						X					X		
Investment Return Guarantee	87				X	X	X							
Night Service GS	88				X									
Night Service HT	89						X					X		
Night Service PD	90					X								
Receivership Rider	91				X	X	X	X	X	X	X	X		X
Residential Direct Load Control Rider	92-94	X	X	X										
Temporary Service	95	X	X	X	X	X	X							

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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.

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.

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PILOT CAPACITY RESERVATION RIDER (CRR) continued

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.

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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No customers who reserves capacity due to pParallel gGeneration will pay more demand charges greater than if the actual load behind its meter . Customers who reserve capacity for business growth or expansion will pay the reserved CRR amount even though it exceeds their current actual load behind the meter. ¶

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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. In addition, these customers will not be able to obtain Competitive Energy Supply.

Based on the applicable level of income, number of household members, and their historical usage CAP customers will receive a Fixed Credit Option ("FCO") based upon that individual household's need. The details of the FCO calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2015-2507139.

DISCOUNT LEVELS: The Company will modify the level of discounts every quarter to adjust for changes in Customer usage as well as any Rate changes which may have occurred.

CERTIFICATION/VERIFICATION Prior to enrollment in the CAP Rider, and then again every two years, 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.
- Apply for and assign to PECO at least one energy assistance grant from the Commonwealth.
- Participate in various energy education and conservation programs facilitated by PECO.

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 the $12 for Residential customers or $30 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP 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. 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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COMMERCIAL/INDUSTRIAL DIRECT LOAD CONTROL PROGRAM (DLC) RIDER

AVAILABILITY.
This rider is available to any small commercial or industrial retail customer with peak measured demands less than or equal to 100kW served under rates GS, PD, or HT that (a) is the owner of the premises at which service hereunder is to be provided; (b) is provided with electric service at such premises through a separate meter; (c) has a fully functional electric central air conditioning system(s) as the principal and dedicated source of air conditioning for such premises, the electric service for which is delivered by the Company through such separate meter and is (are) capable of accepting a programmable communicating thermostat(s) (PCT), as determined by the Company or its agent; (d) allows the Company to periodically control the PCT(s); and(e) is located at a premises where the Company's control signal can reach the connected unit.

For determining the initial eligibility of existing small commercial/industrial retail customers under this rider, the peak measured demand level will be calculated by a process similar to that as described in PECO's Default Service Program pursuant to Docket No. P-2008-2062739. For new customers, the peak measured demand level shall be based upon an engineering estimate of their diversified peak demand for a new facility or an existing facility with a substantially different use. A new customer in an existing facility shall be assigned the same peak measured demand level as the last customer in that facility.

Service hereunder is not restricted to commercial/industrial customers that obtain electric power and energy supply from the Company under Default Service.

Notwithstanding the previous provisions of this Availability section, the availability of this rider is limited by the ability of the Company and its agent to purchase and install the necessary controls needed to implement and administer the Commercial and Industrial Direct Load Control program (DLCP).

PROGRAM PROVISIONS.
The (DLCP) allows the Company to obtain temporary reductions in the electric power and energy demands on the electric delivery system located in its service territory through reductions in the commercial/industrial customers' electric power and energy usage requirements. The Company reserves the right to activate the DLCP for any reason, including (a) response to shortages of available capacity on the Company's distribution system; (b) response to shortages of available capacity on the transmission system located in the Company's service territory; (c) preservation of the availability of other load response resources; or (d) reduction of peak load. A commercial/industrial customer to which this rider is available that elects service hereunder is defined as a participant. An activation of the (DLCP) is defined as an event.

During an event, a participant in the (DLCP) allows the Company to remotely control the PCT(s). The Company is allowed to exercise such control without notice at any time. Control events will be limited to the period beginning June 1 and extending through September 30 of each year, except holidays.

EVENT PERFORMANCE:
During an event the Company is allowed to control the participant's PCT(s) for the total duration of the event.

A participant commences service hereunder on the date the Company inspects and approves the functionality of the participant's central air conditioning unit(s) and installs the programmable communicating thermostat(s).

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COMMERCIAL/INDUSTRIAL DIRECT LOAD CONTROL PROGRAM (DLC) RIDER (continued)

INSTALLATION.
The PCT(s) is (are) an enabling technology necessary to participate in the (DLCP). The PCT(s) will be installed by the Company at its' sole expense (not to exceed the scope necessary to remove the old thermostat(s), and install the new PCT(s)). The Company will warrant the PCT(s) and installation for a period of one year from the date of original installation. After such time, the customer is responsible for any maintenance of the device and battery replacement, when (if required) to ensure the unit continues to operate. The participant is responsible for maintaining a safe operating environment for such device(s).

TESTING & VERIFICATION.
The Company is allowed to inspect the PCT(s) at any time during normal business hours and without notice to insure such device(s) is (are) fully operational, and the participant grants the Company permission to enter upon its premises to conduct such inspections. If, in the course of such inspection, the Company determines that the participant interfered with the functionality of the device(s) in any way, (a) the participant is immediately removed from the (DLCP) and service hereunder is terminated, with such termination effective as of the date of the installation of such device(s) or of the most recent passing inspection, whichever is more recent; (b) all credits previously given to such participant since such effective termination date are immediately reimbursed by such participant to the Company; and (c) such participant is not eligible to take service hereunder or participate in the (DLCP) for a period of not less three (3) calendar years following such effective termination date.

For a situation in which the Company performs excessive maintenance or replacement of any remote control device(s) due to vandalism or other cause, the Company may remove the participant for which such device(s) is (are) provided from the (DLCP) and terminate service hereunder to such participant. In such situation, the Company may deny future participation in the (DLCP) to such participant.

COMPENSATION.
The Company provides a credit to the participant on each bill issued for the Summer Period (June through September for a total of 4 monthly credits), as defined in the Definitions part of the General Terms and Conditions of the Company's Schedule of Rates. The credit applied to such participant's bill corresponds with the Program option selected by such participant.

Programmable Communicating Thermostat Option: $10.00 per bill per installed device for the summer billing period

The participant shall begin receiving the bill credit on the next appropriate bill cycle following a complete enrollment in the program. The total annual credit shall not exceed $40.00 per PCT installed. Consistent with the terms in this tariff, incentives will be paid through October 31, 2020.

The credit provided in accordance with this rider is separately stated on the participant's bill.

MISCELLANEOUS GENERAL PROVISIONS.
The Company is not liable for any damage or injury, including any consequential damage, resulting from the intentional or unintentional interruption of the operation of the participant's central air conditioning unit.

Provisions contained in this rider do not serve to modify the Company's rights contained in the General Terms and Conditions of the Company's Schedule of Rates.

TERMS OF CONTRACT.
The initial term of participation within this program shall end on May 31, 2021, but extended participation is possible, but predicated on future regulatory directives as yet to be determined. As Company is providing the enabling technology device, PCT(s), for participation, there is an early termination provision (upon thirty days' written notice by either party). The Company reserves the right to modify the terms of this Rider at any time. Participants who have elected to terminate, can return to the program, but must wait 12 months before being permitted to do so.

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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, IC; 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.

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.

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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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC)

AVAILABILITY/APPLICABILITY.
Applicable to a service that includes at least one permanently connected and publicly available (or workplace fleet) 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 will begin on July 1, 2019 and continue for five years, expiring on June 30, 2024.

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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, pending issuance of a Final Order on Commission Docket # 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 (or workplace fleet) EVSE solely dedicated to recharging an EV’s battery via the use of direct current. To be considered publicly available, the DCFC must meet both of the following conditions:

- The DCFC is located along a public roadway corridor, at a public charging location, at a multi-dwelling unit (MDU) residential building, or at a workplace for fleet or customer charging.
- The DCFC does not limit its compatibility to an exclusive subset of EVs via the use of proprietary charging networks or technology, including but not limited to communication protocols, connectors, or ports. (Exceptions will be made for DCFCs dedicated solely to workplace fleet 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.

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.

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.

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ELECTRIC VEHICLE DCFC PILOT RIDER (EV-FC) (continued)

OTHER RIDERS.

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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.

TERM OF CONTRACT.

The Company shall provide this credit for no more than 30 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: $14.58

Charge per kW of Off-Peak billing demand per month: $3.00

STATE TAX ADJUSTMENT CLAUSE AND FEDERAL TAX ADJUSTMENT CREDIT APPLIES 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: $11.39
Charge per kW of Off-Peak billing demand per month: $2.27

STATE TAX ADJUSTMENT CLAUSE AND FEDERAL TAX ADJUSTMENT CREDIT APPLIES 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: $11.39
Charge per kW of Off-Peak billing demand per month: $3.00

STATE TAX ADJUSTMENT CLAUSE AND FEDERAL TAX ADJUSTMENT CREDIT APPLIES 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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RESIDENTIAL DIRECT LOAD CONTROL PROGRAM (DLC) RIDER

AVAILABILITY.

Central Air Conditioning Cycling Control Option:

This rider is available to any residential retail customer under rates R, RH, RS-2, and CAP that (a) is the owner of the premises at which service hereunder is to be provided (or can provide an authorization form from the owner); (b) is provided with electric service at such premises through a separate meter; (c) has a fully functional electric central air conditioning system (AC) as the principal and dedicated source of air conditioning for such premises, the electric service for which is delivered by the Company through such separate meter and is (are) capable of accepting a Company control device(s), as determined by the Company or its agent; (d) allows the Company to periodically cycle such AC compressor(s); and (e) is located at a premises where the Company's control signal can reach a control unit mounted near such connected unit.

Electric Water Heater Control Option:

This rider is available to any residential retail customer under rates R, RH, RS-2, and CAP that (a) is the owner of the premises at which service hereunder is to be provided (or can provide an authorization form from the owner); (b) is provided with electric service at such premises through a separate meter; (c) has a fully functional electric water heater, the electric service for which is delivered by the Company through such separate meter and is (are) capable of accepting a Company control device(s), as determined by the Company or its agent; (d) allows the Company to periodically control such electric water heater(s); and (e) is located at a premises where the Company's control signal can reach a control unit mounted near such connected unit.

Service hereunder is not restricted to residential retail customers that obtain full requirements electric supply from the Company under Default Service.

Notwithstanding the previous provisions of this Availability section, the availability of this rider is limited by the ability of the Company and its agent to purchase and install the necessary controls needed to implement and administer the Residential Direct Load Control Program (DLCP).

PROGRAM PROVISIONS.

The DLCP allows the Company to obtain temporary reductions in the electric power and energy demands on the electric delivery system located in its service territory through reductions in residential retail customers' electric power and energy usage requirements. The Company reserves the right to activate the DLCP for any reason, including (a) response to shortages of available capacity on the Company's distribution system; (b) response to shortages of available capacity on the transmission system located in the Company's service territory; (c) preservation of the availability of other load response resources or (d) reduction of peak load. A residential retail customer to which this rider is available that elects service hereunder is defined as a participant. An activation of the DLCP is defined as an event.

During an event, a participant in the DLCP allows the Company to remotely control the duty cycle of such participant's AC compressor(s) and/or control such participant's electric water heater(s). The Company is allowed to exercise such control without notice at any time. Control events will be limited to the period beginning June 1 and extending through September 30 of each year, except holidays.

EVENT PERFORMANCE:

During an event, the Company is allowed to cycle the participant's AC compressor(s) for the full duration of the event, with such cycling performed so that the AC compressor(s) alternates every fifteen (15) minutes between being available for cooling and not being available for cooling.

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RESIDENTIAL DIRECT LOAD CONTROL PROGRAM (RDLC) RIDER (continued)

During an event under the electric water heater control option, the Company is allowed to control the participant's electric water heater for the full duration of the event.

A participant commences service hereunder on the date the Company inspects and approves the functionality of the participant's AC compressor(s) and/or electric water heater and installs the remote control device(s).

INSTALLATION.
The Company or its agent installs the remote control device(s) used to cycle the AC compressor(s) and/or electric water heater(s), and the Company owns, operates, and maintains such device(s). The participant is responsible for maintaining a safe operating environment for such device(s). For a situation in which the participant replaces its AC compressor(s) and/or water heaters, the participant is responsible for providing the Company with adequate notice so that the Company has time to schedule the removal of such device(s) from the AC compressor(s) and/or water heater(s) being removed and the installation of such device(s) on the replacement AC compressor(s) and/or electric water heater(s).

TESTING & VERIFICATION.
The Company is allowed to inspect the remote control device(s) at any time and without notice to insure such device(s) is (are) fully operational, and the participant grants the Company permission to enter upon its premises to conduct such inspections. If, in the course of such inspection, the Company determines that the participant interfered with the functionality of the device(s) in any way, (a) the participant is immediately removed from the (DLCP) and service hereunder is terminated, with such termination effective as of the date of the installation of such device(s) or of the most recent passing inspection, whichever is more recent; (b) all credits previously given to such participant since such effective termination date are immediately reimbursed by such participant to the Company; and (c) such participant is not eligible to take service hereunder or participate in the (DLCP) for a period of not less three (3) calendar years following such effective termination date.

For a situation in which the Company performs excessive maintenance or replacement of any remote control device(s) due to vandalism or other cause, the Company may remove the participant for which such device(s) is (are) provided from the (DLCP) and terminate service hereunder to such participant. In such situation, the Company may deny future participation in the (DLCP) to such participant.

COMPENSATION.
The Company provides a credit to the participant on each bill issued for the Summer Period (June 1 through September 30) for a total of 4 monthly credits. The credit applied to such participant's bill corresponds with the Program option selected by such participant.

Central AC Compressor Cycling Credit: $10.00 per bill per installed device for the summer billing period

Electric Water Heater Control Credit: $10.00 per bill per installed device for the summer billing period

The participant shall begin receiving the bill credit on the next appropriate bill cycle following a complete enrollment in the program. The participant shall receive the applicable bill credit for each device installed. The total annual credit shall not exceed (a) $40.00 per device installed on an AC compressor, and (b) $40.00 per device installed on an electric water heater. Consistent with the terms in this tariff, incentives will be paid through October 31, 2020.

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RESIDENTIAL DIRECT LOAD CONTROL PROGRAM (DLC) RIDER (continued)

The credit provided in accordance with this rider is separately stated on the participant's bill.

MISCELLANEOUS GENERAL PROVISIONS.
The Company or its agent will certify a participant's equipment prior to installation of a load control device. Any equipment determined to not meet the certification standards will be ineligible to participate in the DLCP. Eligible equipment includes fully functional central air conditioning systems and electric water heaters in good condition that are compatible with the load control technology used for the program. Window air conditioning units are not eligible for participation

The Company is not liable for any damage or injury, including any consequential damage, resulting from the intentional or unintentional interruption of the operation of the participant's AC compressor(s) and/or water heater(s). Only CAC units are eligible for program participation. Window mounted air conditioners do not qualify.

Provisions contained in this rider do not serve to modify the Company's rights contained in the General Terms and Conditions of the Company's Schedule of Rates.

TERMS OF CONTRACT.
The initial term of participation within this program shall end on May 31, 2021, but extended participation is possible, but predicated on future regulatory directives as yet to be determined. The Company reserves the right to modify the terms of this Rider at any time. Participants who have elected to terminate, can return to the program, but must wait 12 months before being permitted to do so.

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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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Residential Customer Charges for Major Pennsylvania Electric Utilities

Company	Current Charge
Duquesne	$10.00
MetEd	$11.25
Penelec	$11.25
PennPower	$11.00
PPL	$17.11
West Penn	$7.44
PECO Current	**$8.45**
PECO Proposed	**$12.50**

PECO - 2018 USFC Electric Correction Factor Calculation

Final IPA Balance	**$ 30,100,721**
PECO's Rate Case IPA claim	**$ 44,511,000**
USFC Correction Factor	**0.676**
USFC Annual Adjustment	$ 647,493

	Base Rate Recovery	Correction Factor	Net Recovery
Jan-18	$ 166,667	0.676	$ 112,709
Feb-18	$ 166,667	0.676	$ 112,709
Mar-18	$ 166,667	0.676	$ 112,709
Apr-18	$ 166,667	0.676	$ 112,709
May-18	$ 166,667	0.676	$ 112,709
Jun-18	$ 166,667	0.676	$ 112,709
Jul-18	$ 166,667	0.676	$ 112,709
Aug-18	$ 166,667	0.676	$ 112,709
Sep-18	$ 166,667	0.676	$ 112,709
Oct-18	$ 166,667	0.676	$ 112,709
Nov-18	$ 166,667	0.676	$ 112,709
Dec-18	$ 166,667	0.676	$ 112,709
Total	**$ 2,000,000**		**$ 1,352,507**

PECO Energy Company
Summary of Revenues
12 Months Ending December 31, 2019

Rate	Current Revenue	Proposed Revenue	Increase in Revenue
Residential	$ 1,427,801,684	$ 1,505,940,168	$ 78,138,485
Residential Heating	$ 329,605,169	$ 348,982,944	$ 19,377,775
General Service	$ 756,241,718	$ 778,619,647	$ 22,377,929
Primary Distribution	$ 33,516,372	$ 34,312,979	$ 796,606
High Tension	$ 1,041,039,682	$ 1,060,579,994	$ 19,540,312
Electric Propulsion	$ 58,696,284	$ 59,840,542	$ 1,144,258
Lighting	$ 28,456,417	$ 29,602,958	$ 1,146,541
Total	$ 3,675,357,326	$ 3,817,879,232	$ 142,521,906

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design- Rate Classes Residential (R)

Line			PRESENT RATES		PROPOSED RATES	
	Customer Charges	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	Rate R	15,606,895	$ 8.45	$ 131,878,262	$12.50	$ 195,086,186
2	Second Meter	859,944	$ 1.92	$ 1,651,092	$1.94	$ 1,668,291
3	**Total Customer Charges**	16,466,839		$ 133,529,354		$ 196,754,478
4						
5	**kWh-Based rates**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
6	Rate R	10,518,755,417	$0.06207	$ 652,899,149	$0.06115	$ 643,221,894
7						
8	**Total Distribution Charges**	10,518,755,417		$ 652,899,149		$ 643,221,894
9						
10	CAP discount- Non-distribution			$ (41,845,320)		$ (41,845,320)
11	CAP discount- Distribution			$ (29,078,951)		$ (31,058,935)
12	Energy Efficiency			$ -		$ -
13	Regulatory Initiative			$ 1,841,566		$ 1,841,566
14	Tax Reform			$ (38,537,391)		$ -
15	Rate Case Adjustment			$ 9,758,051		$ -
16	Load Reduction			$ (10,163,598)		$ (10,012,954)
17	Annualization			$ 2,672,377		$ 2,854,339
18				$ (105,353,266)		$ (78,221,303)
19						
20	**Total Distribution Revenue**			$ 681,075,237		$ 761,755,068

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design- Rate Class Residential Heating (RH)

Line				PRESENT RATES		PROPOSED RATES	
	Customer Charges		**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	Rate RH		2,247,564	$ 8.45	$ 18,991,916	$12.50	$ 28,094,550
2	**Total Customer Charges**		2,247,564		$ 18,991,916		$ 28,094,550
3	From Rate RH						
4	**kWh-Based rates**		**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
5	Rate RH	Jun - Sept	665,139,000	$0.06207	$ 41,285,178	$0.06115	$ 40,673,250
6		Oct - May	2,055,961,000	$0.04395	$ 90,359,486	$0.04696	$ 96,547,929
7	**Total Distribution Charges**		2,721,100,000		$ 131,644,664		$ 137,221,178
8							
9							
10	CAP discount- Non-distribution				$ (4,258,773)		$ (4,258,773)
11	CAP discount- Distribution				$ (2,959,486)		$ (3,247,881)
12	Energy Efficiency				$ -		$ -
13	Regulatory Initiative				$ 415,273		$ 415,273
14	Tax Reform				$ (7,821,633)		$ -
15	Rate Case Adjustment				$ 1,984,088		$ -
16	Load Reduction				$ (2,180,313)		$ (2,392,779)
17	Annualization				$ 618,553		$ 678,830
18					$ (14,202,290)		$ (8,805,330)
19							
20	**Total Distribution Revenue**				$ 136,434,289		$ 156,510,399

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design- Rate Class General Service (GS)

Line			PRESENT RATES			PROPOSED RATES		
	Customer Charges	**Bills**	**Rate**		**Revenue**	**Rate**		**Revenue**
1	Single-Phase- No Demand	362,089	14.26	$	5,163,384	$14.54	$	5,265,893
2	Single-Phase- With Demand	1,065,741	18.17	$	19,364,510	$18.53	$	19,748,957
3	Poly-Phase- With Demand	393,382	43.51	$	17,116,032	$44.37	$	17,455,839
4	GS Night Service Rider	34,963	14.30	$	499,964	$14.58	$	509,890
5								
6	**Total Customer Charges**	1,821,211		$	42,143,891		$	42,980,580
7								
8	**kWh-Based Rates**	**kWh**	**Rate**		**Revenue**	**Rate**		**Revenue**
9	Single-Phase- No Demand	8,031,535,267	($0.0006)	$	(4,818,921)	($0.0006)	$	(4,818,921)
10	Single-Phase- With Demand	-	$0.0000	$	-	$0.0000	$	-
11	Poly-Phase- With Demand	-	$0.0000	$	-	$0.0000	$	-
12	GS Night Service Rider	-	$0.0000	$	-	$0.0000	$	-
13								
14								
15	Intercompany- All kWh	37,339,818	$0.0221	$	824,742	$0.02351	$	877,927
16		8,068,875,085		$	(3,994,179)		$	(3,940,994)
17								
18	**kW-based Rates**							
19	GS Night Service Rider	128,655	$ 2.39	$	307,485	$3.00	$	385,965
20	Billed demand kW	26,641,802	$ 7.46	$	198,721,198	$7.94	$	211,535,905
21				$	199,028,683		$	211,921,870
22	**Total Distribution Charges**			$	195,034,505		$	207,980,875
23								
24	Energy Efficiency			$	-			-
25	Regulatory Initiative			$	-			-
26	Tax Reform			$	(12,818,381)			-
27	Rate Case Adjustment			$	3,273,720			-
28	Load Reduction			$	(3,016,565)		$	(3,216,805)
29	Annualization			$	233,500		$	249,000
30				$	(12,327,727)		$	(2,967,805)
31								
32	**Total Distribution Revenue**			$	224,850,669		$	247,993,650

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design- Rate Class Primary Distribution (PD)

Line			PRESENT RATES			PROPOSED RATES		
	Customer Charges	**Bills**	**Rate**		**Revenue**	**Rate**		**Revenue**
1	Rate PD	5,400	296.09	$	1,598,886	296.10	$	1,598,940
2	Rate PD- NSR Fixed	1,524	11.39	$	17,358	$11.39	$	17,358
3	**Total Customer Charges**	5,400		$	1,616,244		$	1,616,298
4								
5	**kWh-Based rates**	**kWh**	**Rate**		**Revenue**	**Rate**		**Revenue**
6	Rate PD	405,541,802	($0.0006)	$	(243,325)	($0.0006)	$	(243,325)
7	Rate PD- NSR Fixed	-	$0.0000	$	-	$0.0000	$	-
8	**Total kWh-Based Charges**	405,541,802		$	(243,325)		$	(243,325)
9								
10	**kW-based Rates**							
11	Rate PD	1,038,613	$ 7.01	$	7,280,676	$7.42	$	7,706,507
12	Rate PD- NSR Fixed	4,002	$ 2.16	$	8,644	$3.00	$	12,006
13	**Total Demand-Based Charges**	1,038,613		$	7,289,320		$	7,718,513
14								
15	**Total Distribution Charges**			$	7,045,995		$	7,475,188
16								
17	Energy Efficiency			$	-		$	-
18	Regulatory Initiative			$	-		$	-
19	Tax Reform			$	(523,440)		$	-
20	Rate Case Adjustment			$	136,805		$	-
21	Load Reduction			$	(97,485)		$	(103,423)
22	Annualization			$	-		$	-
23				$	(484,119)		$	(103,423)
24								
25	**Total Distribution Revenue**			$	8,178,120		$	8,988,063

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design- Rate Class Primary High Tension (HT)

Line			PRESENT RATES		PROPOSED RATES	
	Customer Charges	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	High Tension HT	31,932	299.62	$ 9,567,466	299.63	$ 9,567,785
2	Rate HT- NSR Fixed	12,912	11.39	$ 147,068	$11.39	$ 147,068
3	**Total Customer Charges**	31,932		$ 9,714,534		$ 9,714,853
4						
5	**kWh-Based rates**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
6	High Tension HT	14,887,392,197	($0.0006)	$ (8,932,435)	($0.0006)	$ (8,932,435)
7	Rate HT- NSR Fixed	-	$0.0000	$ -	$0.0000	$ -
8	**Total kWh-Based Charges**	14,887,392,197		$ (8,932,435)		$ (8,932,435)
9						
10	**kW-based Rates**					
11	High Tension HT	33,247,136	$ 4.77	$ 158,455,852	$5.23	$ 173,882,523
12	Rate HT- NSR Fixed	337,965	$ 2.01	$ 679,310	$2.27	$ 767,181
13	33KV	9,118,539	$ (0.15)	$ (1,367,781)	($0.15)	$ (1,367,781)
14	69KV	231,192	$ (0.48)	$ (110,972)	($1.29)	$ (298,238)
15	>69KV	2,432,864	$ (0.48)	$ (1,167,775)	($1.29)	$ (3,138,395)
16	**Total Demand-Based Charges**			$ 156,488,634		$ 169,845,291
17						
18	**Total Distribution Charges**			$ 147,556,199		$ 160,912,856
19						
20	Energy Efficiency			$ -		$ -
21	Regulatory Initiative			$ -		$ -
22	Tax Reform			$ (9,392,973)		$ -
23	Rate Case Adjustment			$ 2,454,931		$ -
24	Load Reduction			$ (3,578,657)		$ (3,902,594)
25	Annualization			$ -		$ -
26				$ (10,516,699)		$ (3,902,594)
27						
28	**Total Distribution Revenue**			$ 146,754,033		$ 166,725,114

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design- Rate Class Electric Propulsion (EP)

Line			PRESENT RATES		PROPOSED RATES	
	Customer Charges	**Bills**	**Rate**	**Revenue**	**Rate**	**Revenue**
1	Electric Propulsion	465	$ 1,292.35	$ 600,943	$1,292.35	$ 600,943
2	**Total Customer Charges**	465		$ 600,943		$ 600,943
3						
4	**kWh-Based rates**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
5	All kWh	625,634,756	($0.0006)	$ (375,381)	($0.0006)	$ (375,381)
6	**Total kWh-Based Charges**	625,634,756		$ (375,381)		$ (375,381)
7						
8	**KW-Based rates**					
9	All kW	1,685,572	$ 4.27	$ 7,199,079	$4.75	$ 8,006,468
10	>69KV-NSR	59,570	$ 2.01	$ 119,736	$2.27	$ 135,224
11	**Total Demand-Based Charges**			$ 7,318,814		$ 8,141,692
12						
13	**Total Distribution Charges**			$ 6,943,434		$ 7,766,311
14						
15	Energy Efficiency			$ -		$ -
16	Regulatory Initiative			$ -		$ -
17	Tax Reform			$ (458,007)		$ -
18	Rate Case Adjustment			$ 120,175		$ -
19	Load Reduction			$ -		$ -
20	Annualization			$ -		$ -
21				$ (337,832)		$ -
22						
23	**Total Distribution Revenue**			$ 7,206,544		$ 8,367,254

PECO Energy Company (Electric)
Rate Year Ended December 31, 2019
Rate Design - Rate Classes Lighting

Line			PRESENT RATES		PROPOSED RATES	
1	**Customer/Location Charges**	**Bills/Locations**	**Rate**	**Revenue**	**Rate**	**Revenue**
2	SL-E	2,119,152	$ 7.11	$ 15,067,169	$6.65	$ 14,092,359
3	TLCL	105,240	$ 3.62	$ 380,969	$3.70	$ 389,388
4	AL	179,940	$ 2.25	$ 404,865	$2.40	$ 431,856
5	**Total Customer Charges**	2,404,332		$ 15,853,003		$ 14,913,603
6						
7	**kWh-Based rates**	**kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**
8	SL-E	143,062,964	$0.00853	$ 1,220,327	$0.01652	$ 2,363,400
9	TLCL	49,199,914	$0.01477	$ 726,683	$0.01620	$ 797,039
10	**Total kWh-Based Charges**	192,262,878		$ 1,947,010		$ 3,160,439
11						
12	**Company Owned Lighting**					
13	SLS	-		$ 2,056,591		$ 2,108,006
14	POL	11,313,964		$ 1,045,370		$ 1,071,505
15	**Total Company Owned Lighting**	11,313,964		$ 3,101,962		$ 3,179,511
16						
17	**Total Distribution Charges**			$ 5,048,971		$ 6,339,949
18						
19	Energy Efficiency			$ -		$ -
20	Regulatory Initiative			$ -		$ -
21	Tax Reform			$ (1,070,748)		$ -
22	Rate Case Adjustment			$ 272,230		$ -
23	Load Reduction			$ (28,219)		$ (28,219)
24	Annualization			$ -		$ -
25				$ (826,737)		$ (28,219)
26						
27	**Total Distribution Revenue**			$ 20,075,238		$ 21,225,334

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-2018-3000164

DIRECT TESTIMONY

WITNESS: RICHARD A. SCHLESINGER

SUBJECT: RETURN OF TAX BENEFITS TO CUSTOMERS UNDER THE TAX CUTS AND JOBS ACT; PROPOSED CHANGES TO PECO ENERGY COMPANY – ELECTRIC DIVISION TARIFF; 2015 RATE CASE SETTLEMENT COMMITMENT REGARDING INTERCONNECTION OF CUSTOMER-OWNED GENERATION

DATED: MARCH 29, 2018

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DIRECT TESTIMONY
OF
RICHARD A. SCHLESINGER

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Richard A. Schlesinger. 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 Manager, Retail Rates. In that capacity, I am responsible for the management and oversight of PECO's electric and gas retail and supplier service tariffs, and oversee numerous filings with the Pennsylvania Public Utility Commission (the "Commission").

3. Q. Please describe your educational background.

A. I have a Bachelor of Science Degree in Engineering from Widener University. In addition, I have a Master's Degree in Business Administration from Saint Joseph's University.

4. Q. Please describe your professional experience.

A. I was hired in 1986 by PECO as a System Engineer in the Plant Operations group supporting the Limerick Nuclear Generating Station. From 1988 to 1991, I held several positions of increasing responsibility supporting plant operations, management, and quality assurance. In 1992, I transferred into the position of

Rate Engineer in the Rates and Regulatory Affairs Group. In 1997, I was appointed to the position of Project Manager, Customer Choice Implementation, and was responsible for many regulatory activities related to the phase-in of electric and gas retail choice for all of PECO's two million electric and gas distribution customers. In 2000, I transferred to the Company's Customer and Marketing Services Department and served as e-Commerce Manager and then as Project Manager, overseeing various Business/Information Technology system implementations. In 2004, I returned to the Regulatory and External Affairs Department, where I served as Principal Rate Administrator.

In 2009, I was promoted to my current position of Manager of Retail Rates. My responsibilities as Manager of Retail Rates include oversight of PECO's gas and electric tariffs as well as over one hundred filings annually with the Commission. In addition, I address regulatory issues involving distributed generation, including interconnection applications and associated reporting.

5. 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. 5 ("Tariff No. 5") that have been incorporated in the Company's proposed Tariff Electric-Pa. P.U.C. No. 6 ("Tariff No. 6") filed in this case. My testimony is divided into several parts. First, I will explain PECO's proposed Federal Tax Adjustment Credit ("FTAC"), which will refund to customers the amount of PECO's reduced tax expense in 2018 resulting from Tax Cuts and Jobs Act (the "TCJA"). The amount of the refund is projected to be $68 million under

PECO's existing rates. Second, I describe proposed changes to Tariff No. 5 consisting of revisions to: (1) terms and definitions; (2) tariff rules and regulations; (3) rate schedules; (4) riders; (5) existing 1307 surcharge mechanisms; and (6) various miscellaneous provisions. Finally, I will discuss the processing times for certificates of completion under the Company's terms and conditions for interconnection of customer-owned generation as revised in accordance with the settlement of PECO's 2015 base rate case.

6. Q. Mr. Schlesinger, have you submitted testimony previously before the Commission?

A. Yes. I submitted testimony in support of PECO's Phase I, Phase II and Phase III Energy Efficiency and Conservation ("EE&C") Plans (P-2008-2062740, M-2009-2093215, M-2015-2515691). In addition, I submitted testimony in support of the Company's Market Rate Transition Energy Efficiency Package (P-2008-2062740) and its Residential Real-Time Pricing Program (P-2008-2032333). I submitted direct and rebuttal testimony in PECO's 2015 base rate case at Docket No. R-2015-2468981.

7. Q. Are you sponsoring any exhibits in this case?

A. No. However, as explained by Mr. Kehl in PECO Statement No. 7, the various tariff changes that I am identifying and explaining are reflected in blacklining of the relevant pages of the Company's proposed Tariff No. 6 that Mr. Kehl is sponsoring as PECO Exhibit MK-2. Accordingly, I will refer to PECO Exhibit MK-2 in certain points in my testimony.

II. PECO'S PROPOSAL TO RETURN TAX BENEFITS UNDER THE TAX CUTS AND JOBS ACT TO CUSTOMERS

8. Q. How does PECO propose to respond to the TCJA, which became effective as of January 1, 2018, and reduced PECO's tax expense?

A. PECO is proposing a reconcilable surcharge mechanism – the FTAC – to expeditiously refund the amount of PECO's 2018 federal tax expense resulting from the TCJA to customers.

By way of background, the TCJA amended or repealed various provisions of the Tax Reform Act of 1986 and resulted in a reduction of the current corporate federal tax rate from 35% to 21%. By Secretarial Letter dated February 12, 2018 ("TCJA Secretarial Letter"), the Commission initiated a proceeding at Docket No. M-2018-2641242 to "determine the effects of the TCJA on the tax liabilities of the Commission-regulated public utilities for 2018 and future years and the feasibility of reflecting such impacts in the rates charged to Pennsylvania utility ratepayers."

After completing its initial review of comments submitted in response to the TCJA Secretarial Letter, the Commission entered an Order on March 15, 2018, pursuant to Section 1310 (d) of the Public Utility Code, directing PECO and other utilities to designate their existing rates and riders as temporary rates (the "Temporary Rate Order"). In compliance with the Temporary Rate Order, PECO filed a supplement to Tariff No. 5 establishing temporary rates on March 16, 2018.

Because the lower federal corporate income tax rate provided in the TCJA was effective January 1, 2018, PECO is proposing to return the associated 2018 tax benefits to customers through the FTAC. The Company's proposed methods to incorporate the effects of the TCJA into PECO's base rates from 2019 forward are described by Mr. Yin in PECO Statement No. 3.

9. Q. Please describe PECO's proposed FTAC.

A. The FTAC is a reconcilable Section 1307 adjustment clause that will function similarly to PECO's existing State Tax Adjustment Surcharge ("STAS"). The FTAC will be computed annually and will be available to address any future changes in the federal income tax rate.

For 2018, the FTAC will be based on the difference in total annual revenue requirement before and after implementing the TCJA, and the calculation will reflect the reduction in required revenues (estimated to be approximately $68 million). The reduction in required revenues will be divided by the estimated annual applicable base revenues to develop the FTAC that will be applied to customers' bills for service rendered during the applicable twelve-month period. The difference between the actual reduction in required revenue and the reduction in revenues produced by the FTAC as applied will be subject to refund or recovery in an annual revision to the FTAC. For consistency with other Commission-approved 1307 surcharge mechanisms, including PECO's Generation Supply Adjustment (GSA) and Transmission Service Charge (TSC), the interest rate on the over or under disbursement will be applied 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-disbursement or under-disbursement occurs, as reported in the Wall Street Journal. For any over/under credit balance that remains after the initial twelve-month refund period for the 2018 tax benefits, the Company may propose additional FTAC adjustments to ensure that the balance is eliminated.

An annual reconciliation statement will be submitted to the Commission each year, and a final reconciliation statement will be filed within 30 days after the final over/under balance has been eliminated. The FTAC revenues and reconciliation will be subject to audit by the Commission's Bureau of Audits. The FTAC has been included in the Company's proposed Tariff No. 6 (see Exhibit MK-2) and references to the application of the FTAC have been included in the rate schedules to which it is proposed to apply.

III. PROPOSED CHANGES TO EXISTING TERMS AND DEFINITIONS

10. Q. Please explain why PECO is proposing to add a definition for the term "Interest Index".

A. Rule 5.6 – Interest On Deposit – consists of two parts (A) and (B) that specify the interest the Company will pay on residential and commercial/industrial customer deposits, respectively. Part (B) of Tariff Rule 5.6 provides that interest will be paid "at the lower of the Interest Index or six percent" without defining the term "Interest Index." Therefore, PECO proposes to add the definition of "Interest Index," as follows: "An annual interest rate determined by the average of one-year Treasury Bills for September, October and November of the previous year." The Interest Index is calculated based on data obtained from the Daily Treasury Bill Rates page of the US Department of Treasury's website. The Company's proposed definition is consistent with the defined term used in the Company's Electric Generation Supplier Tariff (Electric Pa P.U.C. No S 1, Supp. 27, p. 6) and the Electric Generation Supplier Tariffs of other electric distribution companies ("EDCs").

11. Q. Please describe the revisions PECO is proposing to subsection (c) of the definition of "Standard Polyphase Secondary Service" regarding the availability of this service to customers.

The definition for service that is "nominally 120/208 volts, 3-phase, 4 wires" currently limits service capacity to 750 kVA for transformers located inside or outside the customer's building. The definition further provides that, for the capacity to exceed this limit, the only rate option available to the customer is High-Tension Service, or Rate HT. PECO is expanding this provision to align with its current business practices. Specifically, the definition is being revised to permit customers with demands up to 1,500 kVA from transformers located outside the building to request service at 277/480 volts, 3-phase, 4-wires as an alternative to Rate HT. For consistency, PECO is proposing the same change to the availability provision of General Service, or Rate GS, for service that is "nominally 120/208 volts, 3-phase, 4 wires."

IV. TARIFF RULES AND REGULATIONS

12. Q. Please describe revisions that PECO is proposing regarding the standard service that PECO provides to customer premises.

A. PECO's current definition of "Standard Polyphase Service" states that "[o]nly one service is available to a building." In describing single-point delivery, however, Rule 2.2 of the Company's Rules and Regulations implies that PECO can install one or more additional services at other points of consumption. Pursuant to Rule 2.2, PECO has granted customer requests to install additional services in this manner after reasonably determining that it is feasible to do so. Therefore, PECO is proposing the following three related tariff revisions to clarify its standard operating practice:

1. First, PECO is proposing to revise the definition of "standard polyphase secondary" service by adding that the Company will provide standard service to customer premises containing multiple buildings in accordance with Tariff Rule 2.2.
2. Second, PECO is proposing to revise Rule 2.2 of its Rules and Regulations to make clear that additional service installations may only be provided where PECO, in the exercise of its sole discretion, determines that is feasible to do so.
3. Third, PECO is proposing a related change to Rule 3.7, which describes nonstandard service, by adding the

following condition: “(5) Situations where extenuating circumstances exist in the Company’s sole judgment whereby the Company agrees to provide multiple services to one customer located on a premises.”

13. Q. Please describe the revision PECO is proposing to Rule 2.5 of its Rules and Regulations dealing with single-phase service up to 150 kVA.

A. This rule is being revised to reflect the fact that customers can have generation as well as “loads.” Accordingly, PECO proposes to revise Rule 2.5 to clarify that the rule applies to both demand and parallel-generation facilities. For consistency, PECO is also adding new references to “parallel generating capacity” in the definition of “Service” and Rate GS where references to “service capacity” currently exist.

14. Q. Please describe the revision PECO is proposing to Rule 4.2 of its Rules and Regulations.

Rule 4.2, which addresses service contracts, currently provides that an applicant for service “shall abide by these Rules and Regulations and the standard requirements of the Company.” PECO proposes to clarify Rule 4.2 by adding, after “standard requirements of the Company,” the following: “including but not limited to those in PECO’s Electric Service Requirements Manual (“Blue Book”), Builder’s Handbook, Interconnection Guidelines (“Yellow Book” and “Gray Book”), and other additional requirements that PECO will provide upon request.”

15. Q. Please describe the revision PECO is proposing to Rule 6.3 of its Rules and Regulations.

A. In PECO's last base rate case proceeding, PECO made changes to several rules, including Rule 6.3, to make sure that its tariff correctly described the allocation of responsibility for Company-owned facilities and customer-owned facilities.

Under PECO's Tariff Rule 6.4, PECO owns the meters and transformers. Those two Company facilities are sometimes installed on customer-owned facilities on the customer side of the point of delivery. Meters are always installed on the customer-owned meter board, and transformers are often installed on customer-owned facilities; for example, a customer may own a private pole line that extends private service some distance from the road, but because transformation equipment works more efficiently if it is located in close physical proximity to the customer load, PECO may install a Company-owned transformer on the last pole of that private pole line.

The purpose of the changes to Rule 6.3 is to make clear that, notwithstanding such an installation protocol, the customer remains responsible for the provision, ownership, inspection, and maintenance of the customer-owned facilities, even if PECO equipment is attached to those facilities.

16. Q. Please describe the revisions PECO is proposing to Rule 7.2 of its Rules and Regulations.

A. Rule 7.2 sets forth the terms and conditions on which the Company will construct line extensions. In particular, Rule 7.2 states the rules for determining when the customer will have to make a payment toward construction of a line extension – known as a contribution in aid of construction, or “CIAC.” Subparts (a) and (b) of the Rule state that, when a CIAC is required, “A Customer who is not a developer must pay the CIAC in full prior to the construction” of the Line Extension.

PECO proposes to add a clarification to Rule 7.2 to correspond to existing practice. Specifically, although Rule 7.2 states that a customer must pay their CIAC in full before PECO will begin work on the project, for projects requiring significant design work, PECO currently provides the customer with a preliminary cost estimate and then begins work on the detailed design documents upon payment by the customer of a non-refundable deposit equal to 10% of the preliminary cost estimate. When the detailed design work is completed, PECO prepares a final estimate, which is then used to calculate the total final CIAC. Any amounts paid for the detailed design work are subtracted from the remaining CIAC due from the customer.

This practice has several advantages. From the customers’ perspective, it allows them to make a small payment up front, withholding the remainder of the full CIAC payment until later in the process, which can improve customer cash flow. The process also allows the final cost estimate to be based on more precise and detailed design work, which benefits both PECO and the customer seeking a line extension. Finally, the process ensures that detailed design work is only done for those proposed line extensions for which the customer demonstrates serious intent to proceed by making an early payment to fund the design work, thus avoiding false starts and wasted design work.

17. Q. Please explain the revision PECO is proposing to Rule 10.2 of its Rules and Regulations.

A. Rule 10.2 specifies the customer's responsibility for safekeeping of the Company's property located on the customer's premises, including underground electrical conductors. Customers with privately owned or operated underground utility facilities on their premises, such as water, sewer, and gas lines, may have obligations as facility owners under the Pennsylvania Underground Utility Line Protection Law (Act 287) to participate in Pennsylvania One Call and provide approximate locations of such facilities with temporary markings in response to related One Call notifications. During the Company's repair or replacement work on its underground conductors, PECO has discovered that some customers are either unwilling or unable to comply with these obligations and locate these privately-owned facilities themselves in accordance with Rule 10.2. As a result, PECO incurs additional expense to locate and mark the privately owned or operated facilities to ensure safe excavation and complete the required underground conductor work. PECO is therefore proposing additions to Rule 10.2 that reinforce the Act 287 obligations and allow the Company to charge non-compliant customers for any incremental costs incurred. The additions also provide that the Company shall not be liable to customers or any other third parties for any damages to private utility facilities if: (1) the 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 Act 287 because the facility owner is not a member of the Pennsylvania One Call system.

18. Q. Please describe the change PECO is proposing with respect to Rule 14.10 of its Rules and Regulations.

A. Rule 14.10 is a provision that allows customers, under specified conditions, to request the installation of a smart meter ahead of the planned installation schedule for their property location and to pay the incremental cost associated with installing a smart meter outside of the planned schedule. PECO has now installed smart meters for all active residential accounts (other than approximately 20 accounts currently in litigation) and, therefore, this rule is unnecessary and is being eliminated. The existing Rule 14.11 will be renumbered as Rule 14.10 in Tariff No. 6.

19. Q. Please refer to Rule 15.3 of the Company's Rules and Regulations, which is titled "Power Factor Adjustment." Please explain "power factor" and why adjustments are made for "power factor."

A. A customer's power factor is a measure of how efficiently electricity is consumed and is the ratio of working power (kW) to apparent power (kVA). A high power factor (e.g., closer to 100%) indicates efficient utilization of electric power. PECO must increase the total power delivered (apparent power) to make up for the reactive power (kVARs) that is lost by customers with a low power factor. As a result, PECO adjusts customer billing demands based on the measured power factor in the manner set forth under Rule 15.3.

20. Q. Please describe the revisions PECO is proposing to Rule 15.3.

A. Rule 15.3 is being revised to clarify how power factor is measured and how PECO adjusts measured demand for power factor.

21. Q. Please describe the revision PECO is proposing to Rule 17.5 of its Rules and Regulations.

A. PECO proposes to revise Rule 17.5 to clarify that late fees apply to the unpaid balance of final bills that are not paid within a payment period. Thus, if a customer does not pay a final bill on time, the customer is liable for late fees that accrue on the final bill's unpaid balance. This clarification is consistent with PECO's current practice.

22. Q. Please describe the revisions PECO is proposing to Rules 22.1 (f) and 22.1 (g) of its Rules and Regulations.

PECO is proposing revisions to Rules 22.1(f) and 22.1(g) to explain how the proper default service procurement class is determined for a new customer. PECO is restating both rules so that Rule 22.1(f) will apply only to a new customer in a *new* facility and Rule 22.1(g) will apply only to a new customer in an *existing* facility.

V. RATE SCHEDULES

23. Q. Is PECO proposing revisions to Rate R – Residence Service?

A. Yes, PECO is proposing revisions to the "Availability" provisions of Rate R regarding detached garages and farms.

24. Q. Please describe the revisions PECO is proposing to that would apply to detached garages.

A. Detached garages are currently treated as appurtenances under Rate R. In light of recent customer communications on this issue, PECO is proposing revisions to clarify requirements of service to detached garages based on tariff provisions of other EDCs. Specifically, PECO will add tariff language clarifying that Rate R is available to detached garages where the following conditions are met:

(a) The detached garage is located on the same premises as the customer's dwelling unit.

(b) The detached garage is used solely for the domestic requirements of the dwelling unit, such as storage of a residential customer's vehicle.

(c) The detached garage is either served through the same meter as the dwelling unit, or it requires separate metering service because of wiring restrictions or legal requirements.

If a detached garage does not meet the above conditions, PECO will treat the garage as commercial property under Rate GS. Because PECO does not have data for all detached garages in its service territory, PECO will implement this change on a prospective basis after receipt of a customer request if a customer has a detached garage meeting the above conditions and is not currently served under Rate R.

25. Q. Please explain the availability provision of Rate R that currently classifies some farm buildings as residential service and the circumstances under which that classification is applied.

A. Rate R currently applies to customers with both dwellings and farms on their premises when single-phase service is adequate to serve their load and the farm is not operated for commercial purposes. Customers who meet these requirements can receive service at residential rates, which may be lower than rates under Rate GS.

As PECO continues to work with customers on interconnecting increasing amounts of distributed generation to its system, some Rate R customers with farms have expressed concerns that PECO's rate class designation prevents them from installing alternative energy systems with a nameplate capacity greater than 50 kW, in accordance with limitations in the Commission's Alternative Energy Portfolio Standard ("AEPS") regulations at 52 Pa. Code § 75.13(3) for residential service locations. By contrast, service under Rate GS would allow those customers to install alternative energy systems of up to 3 MW under the Commission's regulations at 52 Pa. Code § 75.13(4).

26. Q. How does PECO propose to revise the availability provision to address this customer issue?

A. PECO is proposing to remove all references to farms and farm purposes in Rate R except for the provision addressing single meter service for both farm and domestic farmhouse requirements. These revisions will allow customers with farms to choose Rate GS on a prospective basis and provide flexibility for those customers who may be interested in deploying larger alternative energy systems on their premises.

27. Q. Is PECO proposing changes to Rate GS to coordinate the availability provision of that rate with the revisions being proposed to Rate R?

A. Yes, PECO will add "farms" to the Rate GS availability provisions to align with the farm-related revisions that PECO is proposing to Rate R. No changes to Rate GS availability are necessary to accommodate PECO's changes to Rate R for detached garages.

28. Q. What is Rate RS-2 – Net Metering?

A. Rate RS-2 sets forth the eligibility, terms and conditions that apply to customers with customer-owned qualifying renewable generation that employ "net metering."

29. Q. Is PECO proposing to revise Rate RS-2?

A. Yes. PECO is proposing revisions to clarify Paragraph 3 within the "Billing Provisions" section of Rate RS-2, with specific reference to how PECO applies excess generation credits (in kWh) for customer-generators participating in virtual meter aggregation. In accordance with the Commission's regulations at 52 Pa. Code § 75.12, Paragraph 3 of PECO's RS-2 Billing Provisions provides that a credit is first applied to the meter through which the customer's generating facility supplies electricity to the distribution system (also known as the "host account") and then "equally" through the remaining meters for the customer-generator's account or "satellite" accounts. PECO is proposing revisions to clarify how excess credits are applied "equally" for customer-generators participating in virtual meter aggregation.

Under the current provision, PECO applies a "waterfall" methodology in which any net excess credits remaining after fully offsetting the host account's usage is divided equally between satellite accounts and applied in sequential order. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from the prior account divided equally among the remaining satellite accounts. If there is still excess generation after cascading through the waterfall of accounts, the energy is returned to the host account to offset future energy consumption. The revisions clarify but do not change this methodology.

30. Q. Please describe Rate BLI – Borderline Interchange Service.

A. In certain locations near the borders (edges) of an electric distribution company's service territory, it may be more practical and economical if a utility's customers receive service from the distribution facilities of a neighboring electric utility.

Historically, the Commission has approved rates for various electric distribution companies to permit this type of reciprocal arrangement. Rate BLI is a rate under which PECO may provide electric service under reciprocal agreements to neighboring electric utilities for resale by those utilities to customers in their service territories. Under this rate, PECO provides such service only at delivery points where, in its judgment, it has capacity to furnish service without compromising service to its own customers.

31. Q. Describe the revisions to Rate BLI that PECO is proposing.

A. PECO's current rate structure under Rate BLI consists of two charges, the Investment Charge and the Borderline Interchange Service Charge. The Investment Charge is an amount equal to 1% of the additional investment by PECO in facilities required to deliver and meter the service supplied to a neighboring utility under Rate BLI. The Borderline Interchange Service Charge is currently $0.1486 per kWh. Charges under certain adjustment clauses as specified in Rate BLI also apply.

PECO proposes to revise Rate BLI prospectively for new contracts entered after January 1, 2019. The revision provides that the amount a contracting utility must pay will be based on the applicable PECO retail service rate schedule for the borderline customer, as if the customer was served directly by PECO, rather than based on the Borderline Interchange Service Charge. This change will more accurately reflect the costs PECO incurs by aligning a customer's borderline service with the customer's rate class rather than applying a common service charge.

32. Q. What are Rates POL (Private Outdoor Lighting), SL-S (Street Lighting – Suburban Counties), and SL-E (Street Lighting – Customer Owned Facilities)?

A. All three rates are for lighting service. Rate POL applies to lighting service provided by PECO to residential and commercial customers for private outdoor lighting. Rate SL-S applies to street lighting service provided by PECO-owned lighting facilities to municipal customers outside the City of Philadelphia. Rate SL-E applies to street lighting service provided by lighting facilities owned by municipal customers, including the City of Philadelphia.

33. Q. Is PECO proposing revisions to Rate Schedules POL and SL-S?

A. PECO is proposing several changes to the POL and SL-S rate schedules to use more standardized terms and conditions across all three of these street lighting rate schedules. PECO will revise both schedules by adapting existing language from the SL-E rate schedule where appropriate and correcting inconsistencies between POL and SL-S with regard to form, layout, phrasing, and terminology. For example, PECO proposes to separate the SL-S "Lighting Installations" provision into distinct "Standard Installations" and "Non-Standard Installations" provisions, similar to the current provisions in Rate POL, as well as to modify the Energy Supply Charge language in Rate POL to match the Energy Supply Charge language currently in Rate SL-S.

34. Q. Please describe any additional revisions to Rate SL-S that PECO is proposing for purposes other than standardization.

A. PECO is proposing to apply the same revenue test to standard installations for both rates POL and SL-S. PECO's SL-S rate currently limits Company investment in standard installations "to the extent warranted by the revenue in prospect." This provision is less specific than the provision applied under PECO's POL rate, which limits Company investment "to that warranted by three times the prospective revenue recovered through the Tariff's Variable Distribution Charge." PECO is proposing to include this more specific revenue test provision in Rate SL-S. Both rates pertain to Company-owned lights, and PECO is unaware of any significant differences in standard installation practices between the two offerings that would require the Company to apply this test differently.

35. Q. Is PECO proposing any other tariff changes related to street lighting?

A. Yes. PECO is also proposing a new rate for customer-owned street lighting facilities with smart control technology and changes to Rate SL-E to reduce the Service Location Distribution Charge and increase the Variable Distribution Charge Rate. I will discuss these changes in more detail below. Additionally, PECO is proposing to remove the "Determination of Billing Demand" paragraph in Rate SL-E to remove language related to a billing practice that PECO discontinued as of January 1, 2011 of charging SL-E customers for capacity and is no longer applicable. The first sentence of this section, pertaining to the composition of wattage, will be moved to the "Determination of Energy Billed" paragraph. Finally, for consistency with the POL and SL-S changes above, PECO is proposing to renumber the "Service" paragraph under "Terms and Conditions" from Paragraph 6 to Paragraph 1.

36. Q. Why is PECO proposing a new Rate SL-C (Smart Lighting Control) for "smart" street lighting?

A. PECO has received input from municipalities seeking tariff changes to improve the economics of converting to light-emitting diode ("LED") lighting. Smart street lighting technology allows municipalities to dim their street lights at certain times and to alter the hours of operations in ways that further reduce the energy used by LED street lights. In order to give both municipalities and community associations the opportunity to realize the savings achievable from innovative use of smart street lighting technology, Rate SL-C builds flexibility into the determination of a customer's billed energy to recognize how a customer will actually operate its smart street lights.

37. Q. How will Rate SL-C differ from the existing Rate SL-E, which is available to street lighting customers that own their own facilities?

A. Rate SL-C will differ from Rate SL-E in three respects. First, Rate SL-C will be available only to customer-owned street lighting facilities with Company-approved smart control technology. Second, the Service Location Distribution Charge and the Variable Distribution Charge will differ from the comparable charges under Rate SL-E. Specifically, the Service Location Distribution Charge will be lower and the Variable Distribution Charge will be higher than the comparable charges in Rate SL-E. Third, Rate SL-C will provide customers the opportunity to alter how billed energy is determined in order to recognize the benefits of smart street lighting, which typically employs LED lamps.

38. Q. How will Rate SL-C allow customers to recognize additional savings from "smart" LED street lighting?

A. First, let me provide some context by explaining how billed energy (kWh) is determined under PECO's existing Rate SL-E. Street lights are not metered. The energy used by a street light and its associated components – for example, a photocell – can, however, be determined based on the "manufacturer's rating" in watts of the street light, its components, and its hours of operations. Multiplying the watts by the hours of operation yields the street light's energy use. The effective hours of use are based on street lighting that operates "on all-night, every-night schedules" such that lights are "turned on after sunset and off before sunrise," which results in approximately 4,100 annual operating hours (Rate SL-E, Terms and Conditions, Service). Accordingly, under Rate SL-E, 4,100 hours – or 341.11 average monthly hours – is employed to calculate the monthly amount of energy billed under the Variable Distribution Charge.

As I previously explained, "smart" street lighting can be controlled in ways that impact both the wattage and the effective hours of operation ("burning hours"). Wattage can be altered because smart street lighting provides the opportunity to dim a light's output during certain hours or on certain days. The effective hours of operation of smart street lights are also subject to control, which can alter the operating schedule based on local circumstances by, for example, choosing to turn lights on later and off sooner in certain locations.

A customer that wants to avail itself of this opportunity for savings will need to provide the Company its calculation of energy use based on the street lighting facilities it has installed. The required information must include the manufacturer-rated wattage, monthly burning hours, and dimming percentage or factor for each light. The Company will also require Global Positioning System coordinates for each light.

In addition, the Company reserves the right, at any time and without prior notice, to require that the customer provide PECO data showing the energy actually used by its street lights during a prior billing period in order to confirm customer adherence to the operating parameters used to establish its billed energy. If actual energy usage provided by the customer differs from the billing energy previously submitted by the customer and accepted by PECO, PECO will require the customer to submit updated information for use in revising how the energy usage of the customer will be calculated for prospective billing periods.

39. Q. Why is PECO proposing a Service Location Distribution Charge that is lower and a higher Variable Distribution Charge under Rate SL-C than under the comparable charges under Rate SL-E?

A. PECO is changing the relationship of the fixed (Service Location) and variable charges so that a larger proportion of a Rate SL-C customer's bill is based on a variable charge to provide an incentive for street lighting customers to migrate to

LED lamps. LED lighting uses less electricity to provide the same number of lumens as older lighting technology. However, converting to LED fixtures and lamps requires an up-front capital investment in order to realize the energy savings that LED lighting provides. The up-front capital costs can be a disincentive to converting to LED lighting. Increasing the variable charge relative to the fixed charge, as PECO proposes for Rate SL-C, increases the bill savings a customer can achieve from converting to more efficient LED lighting. Increasing the savings from converting to LED lighting will offset the disincentive created by the need for an up-front capital investment by shortening the pay-back period – the length of time required for the savings in the customer's electric bills to recoup the capital investment.

PECO believes the changes incorporated in Rate SL-C address the interests expressed by municipal lighting customers and are a reasonable means to achieve the energy savings that LED lighting will enable.

PECO is also proposing a revision to the Service Location Distribution Charge and Variable Distribution Charge for customers under Rate SL-E where a larger proportion of the customer's bill will be based on the variable charge.

VI. REVISIONS TO TARIFF RIDERS

40. Q. Is PECO proposing revisions to any existing tariff riders that you will address?

A. Yes. I will address proposed revisions to PECO's Construction Rider, Economic Development Rider, and Night Service GS Rider, Night Service HT Rider and

Night Service PD Rider ("NSRs"). PECO is also proposing revisions to its Pilot Capacity Reservation Rider ("Pilot CRR").

41. Q. Please describe PECO's proposed revisions to its Construction Rider.

A. PECO is proposing to revise its Construction Rider when applied in conjunction with its Pilot CRR for customers anticipating business growth and expansion. PECO's Construction Rider is designed to waive the following guarantees of revenue – power factor adjustment, minimum billing demand, and contract minimum – during or immediately following a customer's major construction or expansion period that will require an upward modification of that customer's contract limits or during a receding load period. However, the Construction Rider is not intended to waive the reservations for distribution capacity under the Pilot CRR because such reserved capacity does not necessarily represent actual demand.

To clarify the applicability of these riders for customers expecting to increase demand, PECO is proposing to add the following statement to the "Other Riders" section of the Construction Rider: "For customers taking service under PECO's Capacity Reservation Rider (CRR), the terms of the Construction Rider shall only apply to demand that is not covered by the CRR Level as defined within the terms and conditions of the CRR."

42. Q. What is PECO's Economic Development Rider ("EDR")?

A. The EDR provides for discounts in the Variable Distribution Service Charge of up to 15% to eligible customers served on Rates GS, PD or HT. Eligible customers must demonstrate employment and load growth or a competitive alternative to PECO electric service and a sustained increase in load and an increase in employment as detailed in the terms of the EDR.

43. Q. Please describe the revisions PECO is proposing to the EDR.

A. PECO is proposing to add additional tariff language to the EDR under Section "Competitive Alternative" Rule II.B.2. as follows: "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 purpose of this revision is to provide a mechanism allowing a customer more flexibility when negotiating agreement terms for new or expanded electric service (for example, by allowing customers to pay Contributions In Aid of Construction, or CIAC, over time).

Additionally, in PECO's last base rate case, the Company expanded the scope of the EDR to non-manufacturing customers even if those customers do not retrofit their buildings to Leadership in Energy and Environmental Design standards. In this proceeding, PECO is proposing under Rule II.B.1 to further clarify that the EDR is available to both manufacturing and non-manufacturing customers as long as the customers have a viable economic alternative to conducting their operations in the PECO service territory.

44. Q. Please describe the revisions PECO is proposing to its NSRs.

A. The nature and purpose of the NSRs are described in Mr. Kehl's testimony, and I will address only the specific tariff revisions. I explained earlier how PECO adjusts customer billing demands based on the measured power factor under Rule 15.3. However, PECO's tariff does not clearly address how power factor impacts the billing of customers served under the terms of the NSRs.

PECO is therefore proposing to add the following statement to the Rate Impact provisions within each NSR: "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." This clarification is consistent with PECO's current practice and provides an incentive to customers served under the NSRs to shift peak demands from on-peak hours to off-peak hours, which by extension may shift the customer's lowest power factor measurement into off-peak hours.

45. Q. What is the Pilot CRR?

A. The Pilot CRR is a rider setting forth the terms and conditions of service that apply to customers who operate their own generation in parallel with the Company's distribution system and, therefore, need to reserve capacity on PECO's distribution system to serve their load when their generators are off-line. The Pilot CRR also applies to customers who want to reserve capacity in excess of their present demand from the PECO distribution system for new business growth or expansion. The Pilot CRR currently set forth in the Company's tariff was the product of the settlement of the Company's 2015 base rate case.

46. Q. Is the Company proposing any changes to the Pilot CRR?

A. Yes, the Company is proposing some minor wording changes for clarification. However, at this time, the Company is not proposing substantive changes to the Pilot CRR, permanently instituting the pilot, or applying the CRR to generators that were online prior to January 1, 2016.

One of the key purposes of the Pilot CRR was to allow PECO the opportunity to apply the CRR rules to customers and collect data on the application of the CRR. However, by its terms the CRR was "grandfathered" so that it did not apply to customers whose generating facilities were online prior to January 1, 2016. PECO has had only eight customers whose generator came online after January 1, 2016 – and because those customers initially submitted requests to PECO to operate generation in parallel with the Company's distribution system in 2015 and thus had made all of their financial decisions regarding its generator prior to the grandfathering date, PECO extended the grandfathering clause to those customers. No additional generators have come online since that date. Consequently, at this time, PECO has no customers on the CRR.

At this time, PECO is aware of about ten customers who are actively considering the installation of parallel generation. Those customers will not be grandfathered, and will be subject to the CRR. PECO expects to gather data from that population of customers and present that data in its next base rate proceeding, along with any Pilot CRR changes that might be warranted by such data.

47. Q. Would you like to address any other issues related to the Pilot CRR?

A. Yes. In the Joint Petition for Settlement from PECO's last base rate case proceeding at Docket R-2015-2468981 ("2015 Settlement"), the Company agreed to collect data regarding the coincident peaks for customers with distributed generation deployed on its system. Specifically, PECO analyzed hourly data for a sample containing approximately 400 solar customers and 40 customers with larger generation (e.g., CHP systems) operating in parallel with the Company's distribution system. The data, which are broken down by combined heat and power ("CHP") customers, intermittent renewable commercial customers and intermittent renewable residential customers, was previously provided to the parties to the 2015 Settlement.

48. Q. Is PECO proposing any new Riders?

A. Yes, PECO is proposing a new Pilot Electric Vehicle Direct Current Fast Charger ("EV DCFC") Rider, or "Pilot EV-FC", to support transportation electrification by encouraging the buildout of publicly available (or workplace fleet) fast charging stations through reduced demand charges. PECO is proposing this five-year pilot, effective July 1, 2019, in order to better understand the potential benefits and challenges associated with offering and serving public EV DCFC installations. Since this will be a pilot, PECO is not speculating on the projected number of customers that might qualify for and enroll on the EV-FC Rider. As a result, PECO is not projecting related capital additions, associated revenues, or associated expenses in this proceeding.

49. Q. Please describe the terms and conditions of the Pilot EV-FC Rider.

A. PECO will apply a demand (kW) credit initially equal to 50% of a DCFC's nameplate capacity rating for customers installing a publicly available DCFC served under base rates GS, PD, or HT. The Company will determine whether an EV DCFC is considered to be eligible based on two factors: (1) Its location, and (2) the utilization of any proprietary charging network or technology that limits its compatibility to an exclusive subset of Electric Vehicles. (Exceptions will be made for DCFCs dedicated solely to workplace fleet charging.) The demand credit will be available for a 30-month term or until the pilot concludes, whichever comes first. 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. PECO will consider a DCFC to be exempt from the resale provisions outlined in Tariff Rule 13.1, pending issuance of a Final Order on Commission Docket # M-2017-2604382. The Pilot EV-FC rider has been included as a tariff page in the Company's proposed Tariff No. 6; see Exhibit MK-2.

VII. SECTION 1307 SURCHARGE MECHANISMS

50. 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 Commission.

51. Q. Is PECO proposing changes to any Section 1307 surcharge mechanisms?

A. Yes, the Company is proposing to revise its Universal Service Fund Charge ("USFC") and to eliminate its Smart Meter Cost Recovery Surcharge ("SMCRS"). The Company also proposes to clarify its billing practices under the Generation Supply Adjustment ("GSA").

52. Q. Please describe the change PECO is proposing to its USFC.

A. PECO is removing selected phase-out language from the C-Factor that was only applicable to 2017. PECO is also removing selected Correction Factor language from the F-Factor that was only applicable to 2016 and 2017. The other terms and conditions of the USFC are not changing.

53. Q. Why is PECO eliminating the SMCRS?

A. PECO rolled its smart meter costs into its base rates in its last base rate case but retained the SMCRS to refund or recoup any over or under collection balance on the effective date of the new base rates. That reconciliation has been completed and there is no need to retain the SMCRS in PECO's tariff.

54. Q. Please describe the change PECO is proposing to the GSA.

A. PECO is proposing to clarify that quarterly changes in the GSA rate are not prorated in calculating generation charges on a customer's bill under PECO's existing billing practices.

VIII. MISCELLANEOUS

55. Q. What are the miscellaneous revisions that are being proposed by PECO and reflected in Tariff No. 6?

A. The miscellaneous revisions fall into two categories. First, PECO proposes changes to align its electric tariff with changes it recently made to PECO's gas tariff. Second, PECO proposes to remove obsolete terms and correct typographical errors.

56. Q. Please describe the revisions in the first category you identified above.

A. PECO is proposing two related revisions, as follows:

Release of Information. Rule 21.2 of PECO's Gas Service Tariff describes the Company's solicitation practices associated with providing Low Volume Transportation gas customers the opportunity to authorize the release of their confidential information. PECO is proposing to add Rule 23.8 to its Electric Service Tariff to mirror Gas Service Tariff Rule 21.2 for electric customers with demands of up to 500 kW.

Billing Options. PECO modified Rule 16.2 in its Gas Service Tariff to clarify that the customer's natural gas supplier is responsible for communicating the billing options to the Company. PECO proposes to add similar language to Rule 17.2 of its Electric Service Tariff, clarifying that the EGS is responsible for communicating the customer's billing option to PECO.

57. Q. Please describe the revisions in the second category you identified above.

A. These are minor revisions that consist of the following:

(1) References in Tariff No. 6 to the Auxiliary Service Rider and the Off-Peak Rider will be removed because those Riders are no longer part of PECO's tariff.

(2) The sentence in the Night Service GS Rider that references "blocking of the energy charges contained in the Variable Distribution Charges CTC" will be removed because PECO no longer charges a Competitive Transition Charge or "CTC."

(3) The acronym "kVa" will be corrected to "kVA" throughout PECO's tariff for technical accuracy.

(4) The explanation of "Standard High-Tension" within the definition of "Service" will be updated to include nominal voltage information and modified from "3 wires" to "3 or 4 wires," consistent with PECO's current practices and consistent with the current explanation of "Standard Primary" service immediately preceding it.

(5) A citation of 52 Pa. Code § 57.81 will be added to Tariff Rule 7.3 to capture the relationship between PECO's terms

and conditions for underground service in new residential developments and Chapter 57 of the Commission's regulations.

(6) The reference to Procurement Class 3 will be removed from the Auction Revenue Rights paragraph on the GSA tariff page for Procurement Classes 1 and 2.

(7) The reference to Tariff Rule 22 will be removed from Paragraph (b) under "Determination of Demand" on the Rate GS General Service page.

(8) The phrase "(Purchased Generation Adj.)" will be added to the GSA tariff page for Procurement Class 3/4 in the "E-Factor" of the GSA formula to correspond to the name used to explain this term in the glossary of terms provided on the reverse side of the first page of a customer's bill for clarification based on the customer's feedback.

IX. INTERCONNECTION OF CUSTOMER-OWNED GENERATION

58. Q. In the Joint Petition for Settlement of Rate Investigation which the Commission approved in PECO's last base rate proceeding at Docket No. R-2015-2468981, the Company agreed to revise its terms and conditions for interconnection of customer-owned generation and committed to use best efforts to provide certificates of completion ("COCs") within specific time periods. Has the Company satisfied this commitment?

A. Yes. In 2016 and 2017, approximately 85% of the 1,452 COCs for which PECO has adequate data were returned within 10 business days of the date of either (1) a successful witness test or inspection; or (2) a waiver of the witness test/inspection requirement by the Company. I am not aware of any formal or informal complaints from customers during that period regarding the processing time for COCs.

As discussed by Mr. Innocenzo, PECO launched a distributed generation interconnection portal in November of 2017 that allows developers and customers to submit their applications online and track the progress and status of applications. In addition to streamlining the interconnection process, developers and customers can electronically sign and submit COCs to PECO for final approval. PECO confirms receipt of the signed COCs and tracks the COC final approval processing time for each application.

X. CONCLUSION

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

A. Yes, it does.